BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF A COMMISSION INVESTIGATION INTO XCEL ENERGY'S MONTICELLO LIFE CYCLE MANAGEMENT/EXTENDED POWER UPRATE PROJECT AND REQUEST FOR RECOVERY OF COST OVERRUNS

DOCKET NO. E002/CI-13-754
OAH DOCKET NO. 48-2500-31139

DIRECT TESTIMONY OF CHRISTOPHER J. SHAW

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE,
DIVISON OF ENERGY RESOURCES

JULY 2, 2014

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I. QUALIFICATIONS

Q. Please state your name, occupation, and business address.

A. My name is Christopher J. Shaw. I am a Public Utilities Rates Analyst with the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC). My business address is: 85 7th Place East, Suite 500, St. Paul, Minnesota 55101-2198.

Q. What is your educational and professional background?

A. My educational and professional background is summarized in DOC Exhibit No. ___ (CJS-1).

II. PURPOSE OF TESTIMONY

Q. What are your responsibilities in this proceeding?

A. Overall, the goal of this proceeding is set out on page 19 of the Commission's *Findings of Fact, Conclusions of Law and Order* in the prior general rate case of Northern States Power, d/b/a Xcel Energy (Xcel or the Company), which stated:

> The Commission will open a separate docket to investigate whether the Company's handling of the LCM/EPU project was prudent, and whether the Company's request for recovery of the Monticello LCM/EPU cost overruns is reasonable.

My responsibilities are to review the Strategist modeling performed by Xcel as described in the Direct Testimony of Xcel Witness Mr. James Alders. I also analyze the cost-effectiveness of the life-cycle management (LCM) project and the extended power uprate (EPU) project using updated capital costs for the LCM and EPU projects.

I note that Mr. Mark Crisp provides testimony on behalf of the Department that includes a review of Xcel management of the LCM and EPU projects and Dr. William Jacobs provides testimony regarding the appropriate allocation of capital investment between the LCM and EPU projects. Finally, DOC Witness Nancy Campbell provides accounting testimony regarding the LCM and EPU projects, including the Department's recommendation regarding the appropriate level of cost recovery for the LCM and EPU projects in rates.

Q. Please summarize your testimony.

A. The first portion of my testimony describes the previous Strategist modeling performed by Xcel and the Department during the Certificate of Need proceeding, MPUC Docket No. E002/CN-08-185, in which the Commission granted authority to Xcel to construct the Monticello EPU. I also briefly discuss the 2005 Certificate of Need proceeding in which the Commission granted authority to Xcel for an Independent Spent Fuel Storage Installation (ISFSI) at the Monticello Generating Plant and the 2011 Notice of Change Circumstance (2011 NOCC) subsequently filed by Xcel.

The second portion of my testimony is my review of the Strategist modeling conducted by Xcel in this proceeding, my updated modeling based on the DOC analysis in the 2008 CN updated to reflect the expected actual costs of the Monticello LCM and EPU, and my general discussion of various aspects of the Monticello resource as a component in Xcel's portfolio of resources.

III. BACKGROUND OF PRIOR PROCEEDINGS

Q. Please briefly describe the Department's analysis regarding costs in the 2005 ISFSI CN.

A. In 2005, Xcel filed an Application for a Certificate of Need for an Independent Spent Fuel Storage Installation at the Monticello Generating Plant[1] (ISFSI CN). As part of that proceeding, the Department reviewed the cost-effectiveness of extending the life of Monticello and concluded that the life extension was cost effective. At the time of the ISFSI CN, Xcel estimated the cost of the LCM at $135 million.[2] On October 23, 2006, the Commission issued its *Order Granting Certificate of Need for Independent Spent Fuel Storage Installation* in Docket No. E002/CN-05-123. I note that the ISFSI CN pertained only to the $55 million ISFSI and not to the $135 million LCM. Xcel stated that the ISFSI was needed irrespective of whether Monticello's operating license was extended or whether the capacity of the plant was increased.[3] The costs of the ISFSI are not at issue in this proceeding and have not been included in Xcel's Strategist modeling[4] as an issue to be analyzed in this proceeding or in the additional Strategist modeling that I conducted.

Q. Please briefly describe the 2008 EPU CN filed by Xcel.

A. As noted by Xcel Witness Mr. Alders, in Xcel's 2004 Integrated Resource Plan (IRP) the Commission ordered Xcel to file any required certificate of need for the

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[1] MPUC Docket No. E002/CN-05-123.
[2] DOC IR 94, Responses Attached as DOC Exhibit No. ___ (CJS-2).
[3] *Id.*
[4] *Id.*

Monticello plant no later than September 1, 2007.[5] At the Company's request, the Commission subsequently delayed the deadline until December 14, 2007[6] and again until January 2008.[7] On February 14, 2008, Xcel submitted a petition for a certificate of need for the Monticello EPU[8] (2008 EPU CN). Xcel estimated the cost of the EPU to be $133 million including $29 million to install a new steam dryer (that is, without the steam dryer, Xcel's estimated EPU cost was $104 million) in 2008 dollars.[9]

Under its base case assumptions, Xcel calculated that the Monticello EPU would result in a net present value of revenue requirements (PVRR) savings of $169 million in 2008 dollars, compared to the next best alternative.[10] When the $29 million cost of the new stream dryer was included, the projected PVRR savings was reduced to $128 million.[11] Xcel's baseline cost assumptions were the same assumptions used in the Company's 2007 IRP.[12] Those assumptions include a $20 per ton cost of CO_2 emissions starting in 2010, escalated at 2.5 percent per year, and a natural gas cost of $8.38 per MMBTU in 2008 dollars. Excerpts from Xcel's IRP describing additional assumptions are included as DOC Exhibit No. ___ (CJS-3).

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[5] ORDER AFTER RECONSIDERATION CLARIFYING FILING REQUIREMENTS, REQUIRING NOTICE TO ALTERNATIVE PROVIDERS, SETTING DEADLINES FOR BASELOAD PROPOSALS, AND ACCEPTING REPORTS, October 18, 2006, Docket No. E002/RP-04-1752.
[6] ORDER SUSPENDING CONTESTED CASE PROCEEDING, DELAYING FILING DATES, AND ADVANCING DATE FOR FILING NEXT RESOURCE PLAN, October 22, 2007, Docket Nos. E002/RP-04-1752, E002/M-07-2, E002/CN-06-1518.
[7] PROPOSED SCHEDULE FOR SUSPENDED PROCEEDINGS, December 14, 2007, Docket Nos. E002/RP-04-1752, E002/M-07-2, E002/CN-06-1518.
[8] Docket No. E002/CN-08-185.
[9] Docket No. E002/CN-08-185, Xcel Petition at 1-6.
[10] Docket No. E002/CN-08-185, Xcel Petition at 6-18.
[11] *Id.*
[12] Docket No. E002/RP-07-1572

Q. Please briefly describe the DOC's review of Xcel's 2008 EPU CN.

A. In the 2008 EPU CN proceeding, the DOC reviewed the cost-effectiveness of the proposed Monticello EPU by comparing the costs as presented by Xcel for the EPU ($133 million including the steam dryer) to other alternatives available to meet Xcel's capacity and energy needs. Like Xcel, the DOC used the Strategist capacity expansion model to compare the Monticello EPU to alternative capacity expansion options. The DOC relied on its preferred case as developed in the 2007 Xcel IRP proceeding. Those assumptions included a $17 per ton cost of CO_2, the midpoint of the Commission's range of $4 to $30 per ton, and the same gas costs relied upon by Xcel. Excerpts from the DOC's (formerly the Office of Energy Security, or OES) comments on Xcel's 2007 IRP regarding the DOC's preferred case and preferred case expansion plan are attached as DOC Exhibit No. ___ (CJS-4).

In the 2008 EPU CN proceeding, the DOC compared the proposed Monticello EPU to a biomass alternative, a wind alternative, a coal alternative, and an unconstrained alternative, which allowed the Strategist model to choose the most cost effective options to meet needs.[13] Under the unconstrained main case, the DOC concluded that the Monticello EPU would result in approximately $330 million in 2008 dollars in terms of net present value of social costs (PVSC) savings as compared to the next best alternative. Excerpts from Dr. Steve Rakow's Direct Testimony regarding the cost-effectiveness of the Monticello EPU in the 2008 EPU CN are included as DOC Exhibit No. ___ (CJS-5).

[13] Even though Department Witness Dr. Steve Rakow determined that a coal facility could not be built by the 2011 date proposed for the EPU, the Department included a coal alternative in its analysis to provide a broad range of cost information to the Commission.

Q. What is the difference between the PVSC and PVRR?

A. The PVSC incorporates the effects of externality costs set by the Commission for several power plant emissions. PVSC reflects the reduced emissions from a nuclear power plant such as Monticello and an alternative such as a natural-gas fired generation facility. The PVRR does not include the externality costs of emissions or any other factors.

Q. Did Xcel update its assumptions in the 2008 EPU CN based on the Department's Direct Testimony in the EPU CN and the DOC's 2007 IRP comments?

A. Yes. On September 29, 2009, Xcel submitted supplemental testimony which updated its modeling analysis by incorporating a new, lower forecast, increased demand-side management, changes to address the June 16, 2008 DOC comments in the 2007 IRP, changes related to the move from the Mid-Continent Area Power Pool (MAPP) reserve sharing group to the Midwest Reliability Organization (MRO) and other updates including updated fuel costs. A copy of Xcel's supplemental testimony is included as DOC Exhibit No.___ (CJS-6).

Q. Did Xcel's updated assumptions change the cost-effectiveness of the Monticello EPU?

A. Yes. Using its updated assumptions, Xcel concluded that the EPU would result in a net PVSC savings of $196 million as compared to an unconstrained alternative which allowed the Strategist model to choose the most cost effective options to meet needs.

Q. In granting the CN for the Monticello EPU, did the Commission rely on Xcel's modeling or the Department's modeling?

A. It appears that the Commission relied on both. The Commission accepted, adopted and incorporated the findings, conclusions, and recommendations of the ALJ.[14] The ALJ relied on the Strategist modeling performed by both the Department and Xcel and concluded that:

> 88. Xcel Energy and the OES have analyzed a comprehensive list of potential alternatives to this project. It would be neither reasonable nor prudent of Xcel Energy to choose any of them over the Monticello power uprate.[15]

Q. Did Xcel make any other noteworthy filing in the 2008 EPU CN docket?

A. Yes. On November 22, 2011, Xcel submitted a Notice of Changed Circumstances (NOCC) in the 2008 EPU CN docket. In the original CN petition, the 71 MW EPU was to be placed in-service in 2011. Xcel's NOCC indicated that the 71 MW EPU would not be in-service until 2013.

Based on this information, the Department repeated its Strategist analysis using Xcel's updated timing assumptions for the Monticello EPU. The Department again concluded that the Monticello EPU was cost-effective.[16] I note that Xcel did not update the costs for the EPU in the NOCC in the CN docket to reflect Xcel's significant cost increases of which Xcel was aware at that time; DOC Witness Ms. Nancy Campbell provides Direct Testimony on this issue.

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[14] ORDER GRANTING CERTIFICATE OF NEED AND ACCEPTING ENVIRONMENTAL ASSESSMENT, January 8, 2009, Docket No. E002/CN-08-185.
[15] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION, November 19, 2008, Docket No. E002/CN-08-185.
[16] DOC Comments, December 14, 2011, Docket No. E002/CN-08-185.

IV. STRATEGIST ANALYSIS

Q. Did Xcel conduct additional Strategist modeling in this proceeding?

A. Yes. As in the 2008 EPU CN and 2007 IRP proceedings, Xcel analyzed the cost-effectiveness of Monticello using the Strategist capacity expansion model. Mr. Alders provided a brief description of the Strategist model on pages 27-29 of his Direct Testimony. Xcel divided its analysis into four parts: 1) "Hindsight" analysis, 2) "Foresight" Analysis, 3) Implementation Analysis, and 4) Incremental Value of EPU. Below I address each analysis in turn.

1. "Hindsight" or 2008 EPU CN Analysis

Q. Please describe Xcel's "hindsight" or 2008 EPU CN analysis.

A. First, the word "hindsight" does not accurately reflect the purpose of this analysis. The word "hindsight" means to understand a past event *only after* it has occurred. The Commission is engaged in a prudency review, not a "hindsight" review. In the interest of clarity, I call this analysis the 2008 EPU CN analysis. Prudency asks whether Xcel has shown it acted in a reasonable manner, based on information it knew or reasonably should have known at the time and includes consideration of the information Xcel provided to the Commission in 2008, whether Xcel kept regulators reasonably informed about cost increases, and whether Xcel has shown that it managed its costs appropriately, among other considerations.

Xcel's 2008 EPU CN analysis compares continued operations at Monticello, including the EPU, to a scenario in which Monticello is shut down and replaced with a natural gas combined cycle plant. Xcel began its analysis by using the Company's

September 2008 IRP reply comments model, which Xcel also used in the 2008 EPU CN proceeding as discussed above. Xcel updated the model to include the $665 million in costs incurred for the Monticello LCM and EPU through 2013 as shown on Xcel Exhibit ___ (TJO-1), Schedule 7. In addition, Xcel updated the forecast of additional capital investments necessary at the plant from 2013-2030. For the replacement scenario, Xcel added a new 627 MW natural gas combined cycle plant based on the assumptions used in the 2008 EPU CN Strategist model.

Q. Did Xcel conclude that the Monticello LCM and EPU continues to be cost-effective even with the updated costs?

A. Yes. Xcel concluded that, compared to a complete shutdown of Monticello in 2011 and replacement of the entire facility with a natural gas fired combined cycle plant, the Monticello LCM and EPU resulted in net PVSC of $1,311 million.[17]

Q. Did you confirm Xcel's results?

A. I requested all of the necessary base files, macros, and spreadsheets from Xcel in order to replicate their modeling and results tables. I concluded that Xcel appropriately used its September 2008 IRP reply comments Strategist base file updated to reflect the $665 million cost for the Monticello LCM and EPU. However, I made one minor change to the capacity of the EPU. Xcel had included an interim addition of 12 MW of capacity for 2010-2013. While that interim addition was planned, it did not occur. I adjusted the capacity of the Monticello EPU down by 12 MW, to 600 MW, for the years 2010-2013. This change has a minor impact as

[17] Alders Direct, p. 34.

shown below. I also provide Table 5 of Mr. Alders' Direct Testimony below for comparison.

Table 1: Xcel 2008 EPU CN Analysis (Table 5 of Alders Direct)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommission (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$893
Monti Total	$4,266

Monticello Retirement and Replacement	PVSC Results $millions
Monti Decommissioning (2011)	$423
Replacement Capacity	$1,615
Replacement Energy	$2,954
Incremental Emissions	$585
Total Retirement Costs	$5,577
Net PVSC (Savings)/Costs	**($1,311)**

Table 2: DOC 2008 EPU CN Analysis (Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommission (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$889
Monti Total	$4,262

Monticello Retirement and Replacement	PVSC Results $millions
Monti Decommissioning (2011)	$423
Replacement Capacity	$1,613
Replacement Energy	$2,934
Incremental Emissions	$615
Total Retirement Costs	$5,585
Net PVSC (Savings)/Costs	**($1,323)**

Q. What do Tables 1 and 2 show?

A. Tables 1 and 2 above show that the 12 MW change in the capacity slightly decreases the operation and maintenance (O&M) cost for the EPU, but also slightly decreases the necessary replacement capacity and energy in the retirement scenario. The reduction in capacity also slightly decreases the incremental emissions in the retirement scenario; however the decrease was offset due to an error in Xcel's table in which the final two years of life extension scenario emissions costs were not included in the discounted cost stream. Thus, the net of these changes increases by $12 million the cost effectiveness of the total Monticello LCM and EPU as compared to the retirement and replacement scenario ($1,323M - $1.311M = $12M).

Q. Why is it appropriate to use models from 2008 to assess whether the Monticello LCM and EPU costs are cost-effective?

A. For this analysis, is it not reasonable to expect that Xcel would have perfect foresight of all assumptions used in the Strategist model. However, it is important for this prudency analysis to update the cost information since Xcel should have had better information about the costs of the project, as indicated in the testimony of Mr. Mark Crisp. Xcel should provide reasonably accurate cost estimates for the Commission to consider in CNs for projects the Company proposes to build.

Thus, this analysis looks at whether the same decision to proceed with the project would have been made in 2008 if the total costs of the Monticello LCM and EPU project had been used at that time. Other assumptions, such as fuel costs and energy and demand forecasts that have changed since 2008, were not updated. Rather, other than Monticello costs, all assumptions reflect the best estimates that were available in 2008.

Q. Why is it important for Xcel to provide reasonably accurate cost estimates in CNs for projects it proposes to build?

A. As the Department has stated in past proceedings,[18] cost estimates are used extensively in CN proceedings and relied upon by the Commission in comparing proposed projects to alternatives. Thus, this comparative analysis requires reasonable cost estimates to ensure that this cost comparison is valid. Since comparisons of proposed projects to alternatives based on relative costs is a critical part of any CN analysis, it is important for utilities to provide accurate estimates of project costs; not doing so adversely affects the integrity of the CN process and could harm ratepayers.

Further, approval of utility projects in CNs and similar proceedings is not a blank check for any utility to recover from ratepayers all costs that are incurred to construct a project. In rider filings for example, the Department has routinely recommended that cost recovery be capped in the rider rates at the level of costs approved in the CN to ensure that utilities have the appropriate incentives to provide reasonably accurate cost estimates of proposed projects in CNs and to minimize those costs in practice. The integrity of CN proceedings depends on utilities providing reasonably accurate information, such as cost estimates.

Even though rider recovery is typically limited to the cost estimates in a utility's CN, a utility is free to try to demonstrate to the Commission in its subsequent rate case, or in a proceeding such as this, that costs in excess of the CN-approved

[18] See *e.g.,* DOC Comments, p. 7-8, Docket No. E017/M-13-103; DOC Comment, p. 16, Docket No. E002/M-12-50. DOC Witness Ms. Campbell provides additional discussion of proceedings before the Commission in which costs have been capped.

levels are reasonable to charge to ratepayers; however, the burden is on the utility to make such a showing if it wants to recover cost overruns from ratepayers.

As the Commission stated in its April 22, 2010 Order Approving 2010 RES Rider, etc. regarding to cost caps in Xcel's RES rider (Docket No. E002/M-09-1083):

> Xcel will be allowed to seek recovery, on a prospective basis, of additional costs at the time of its next rate case, upon a showing that it is reasonable to require ratepayers to pay for any such additional costs. This approach allows Xcel to recover the majority of the costs for projects eligible for RES rider recovery promptly, while providing at least some incentive for Xcel to minimize costs and help protect ratepayers.[19]

Q. Why did you change by 12 MW the capacity of the Monticello EPU compared to what Xcel modeled?

A. I changed the capacity in order to reflect the actual timing of the capacity increase. For this analysis, the objective is to determine the present cost-effectiveness of the Monticello LCM and EPU projects assuming that both the estimate of costs and actual timing of the uprate were accurate in 2008.[20]

Q. Based on Table 2 above, do you agree with Xcel's conclusion that, compared to a complete shutdown of Monticello in 2011 and replacement with a natural gas fired combined cycle plant, the Monticello LCM/EPU resulted in net present value societal cost savings (PVSC) of $1,323 million (based on the 12 MW adjustment you discuss above)?

[19] Order, Docket E002/M-09-1083, April 22, 2010.

[20] I note that I have assumed the full 671 MW of capacity was available beginning in 2014. However, Monticello has not achieved that level of output and the appropriate cost-recovery in 2014 is a pending issue in Xcel's rate case in Docket No. E002/GR-13-868. My simplifying assumption, which gives a benefit to Xcel, does not indicate the Department's position on the appropriate in-service date for the EPU for determining cost recovery in 2014.

A. No. As discussed below I agree that the combined LCM/EPU is overwhelmingly cost-effective as a whole; further, I conclude that, with the change in capacity discussed above, Xcel has reasonably modeled the impacts of the Monticello LCM and EPU on Xcel's system using the Strategist model. However, I do not conclude that Tables 1 and 2 above accurately show the net PVSC savings. In my review of the Strategist outputs used to create Table 5 of Mr. Alders' Direct Testimony, I conclude that Xcel did not correctly discount the cost streams.

Specifically, Xcel discounted costs incurred after 2013 back to 2013 dollars, while simply summing costs incurred prior to 2013 rather than escalating those costs to 2013 dollars. Thus, Xcel's calculation mixes real and nominal cost values as costs incurred prior to 2013 were not escalated to 2013 dollars. Moreover, because the purpose of this analysis is to re-evaluate the decision made in 2008, costs should be discounted back to 2008 dollars. The result of this change is shown below:

Table 3: DOC 2008 EPU CN Analysis-2008 Base Year (Xcel Base Model)

Monticello Life Extension + EPU	**PVSC Results $millions**
Monti Decommission (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello Retirement and Replacement	**PVSC Results $millions**
Monti Decommissioning (2011)	$283
Replacement Capacity	$1,058
Replacement Energy	$1,925
Incremental Emissions	$400
Total Retirement Costs	$3,667
Net PVSC Savings	**($886)**

Q. What does your Table 3, incorporating corrections to Xcel's analysis, show?

A. My analysis shows that this change to a 2008 base year has a significant effect on the net PVSC savings. However, again, the results continue to show that, as compared to retirement and replacement, continuation of operation of Monticello, including the EPU, is overwhelmingly cost-effective.

Q. Beyond your corrections to Xcel's analysis, did you perform an additional analysis of the combined Monticello LCM and EPU?

A. Yes. In addition to the analysis discussed above, I used the DOC base Strategist files from the 2008 EPU CN and 2007 IRP, discussed earlier in my testimony, and updated those files to reflect the actual costs and capacity timing of the Monticello LCM and EPU. In other words, I performed the same analysis discussed above, but I used the DOC base file instead of the Xcel base file. To provide a complete apples-to-apples comparison, I present below the results of that analysis using Xcel's discounting method and the discounting method I recommend, using 2008 as the base year:

Table 4: DOC 2008 EPU CN Analysis – Xcel's Discount Method (DOC Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommissioning (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,939
Monti Fuel	$739
Monti Total	$4,093

Monticello Retirement and Replacement	PVSC Results $millions
Monti Decommissioning (2011)	$423
Replacement Capacity	$1,646
Replacement Energy	$2,770
Incremental Emissions	$643
Total Retirement Costs	$5,482
Net PVSC Savings	**($1,390)**

Table 5: DOC 2008 EPU CN Analysis-2008 Base Year (DOC Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommission (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,271
Monti Fuel	$484
Monti Total	$2,668

Monticello Retirement and Replacement	PVSC Results $millions
Monti Decommissioning (2011)	$283
Replacement Capacity	$1,080
Replacement Energy	$1,821
Incremental Emissions	$421
Total Retirement Costs	$3,605
Net PVSC Savings	**($937)**

Q. What do your Tables 4 and 5 show regarding the combined LCM and EPU projects as a whole, based on the DOC's base case from the 2008 CN?

A. These tables show that the DOC base model produces results that are similar to the Xcel base model, except that they show slightly higher benefits of the continued operation than Xcel's base case of Monticello, including the EPU. Thus, as compared to complete shut down and replacement, the continued operation of Monticello and the EPU is overwhelmingly cost-effective using either the DOC or Xcel base models.

2. "Foresight" Analysis

Q. Please describe Xcel's foresight analysis.

A. In Xcel's foresight analysis, the Company used the Strategist base model from the recent competitive resource acquisition docket.[21] Those assumptions were generally developed in 2013 and include the significantly lower gas prices and lower load forecast as compared to what was known in 2008. Mr. Alders further described the assumptions included in the base model from the competitive resource acquisition docket on pages 36-38 of his Direct Testimony.

Q. Did you review the modeling Xcel conducted in its foresight analysis?

A. No. My testimony is focused on the decision to proceed in 2008 if accurate estimates of the final costs and scheduling of the Monticello LCM and EPU were known at the time. Xcel states that it could not have anticipated the Great Recession of 2009 or the advent of hydraulic fracturing and horizontal drilling that dramatically lowered the cost of natural gas.[22] However, Xcel believes that the foresight analysis provides a useful data point for the Commission's consideration.[23]

I agree that Xcel could not have anticipated the significant changes due to the Great Recession and hydraulic fracturing. Moreover, the purpose of a prudence review is to assess whether the utility made the correct decisions based on information that was or should have been available at the time of that decision. The assumptions included in the base files used in the 2008 EPU CN represent the best

[21] Docket No. E002/CN-12-1240.
[22] Alders Direct at p. 35.
[23] *Id*.

estimates of load growth and fuel prices at the time of the Commission's CN approval.

Thus, while Xcel's foresight analysis may provide "a useful data point" for the Commission, it is not the appropriate method to use to determine the prudency of Xcel's 2008 decision to proceed with the EPU and whether it is likely the Commission would have approved the EPU CN if Xcel had provided cost estimates that reasonably would have reflected the project's likely actual costs.

Based on the pertinent prudency question focused on the decision to proceed in 2008 had accurate estimates of the final costs and scheduling of the Monticello LCM and EPU been used at the time, as I stated above, continued operation of Monticello, including the EPU, as compared to shut down and replacement is overwhelmingly cost-effective.

3. Implementation Analysis

Q. Please describe Xcel's implementation analysis.

A. Xcel performed an implementation analysis which evaluated cost-effectiveness and the prudency of Xcel's decisions in each year from 2008 to 2013 by comparing the costs of the combined Monticello LCM and EPU to a scenario in which Monticello was retired and replaced. Xcel called these costs the "cost to complete" or "costs to go" to complete the project. Xcel used the updated $665 million cost of Monticello with a different base file for each year, 2008-2013, as follows:

- 2009: September 2009 Black Dog Analysis model;
- 2010: July 2010 Resource Plan model;

- 2011: September 2011 Resource Plan Update model;
- 2012: September 2012 Prairie Island EPU re-evaluation proceeding model; and
- 2013: September 2013 Competitive Resource Acquisition model[24]

The Company ran the Strategist model using these base models updated for the $665 million Monticello LCM and EPU costs. The Company's analysis had two subcomponents: one included an adjustment for sunk costs up to the relevant year,[25] the second excluded such an adjustment for sunk costs.[26] In each case the Company concluded that continued operation of Monticello, including the costs of the EPU, was more cost-effective than shutdown and replacement.

Q. Did you review the modeling Xcel conducted in its Implementation Analysis?

A. No, for several reasons. First, while I would expect the Company to conduct ongoing internal analyses to assess whether it was prudent to continue with the project as the Company was aware of facts such as increased costs, this "cost to complete" approach assumes that Xcel knew at each year how much more costs the Company would incur.

Second, Xcel's implementation analysis would provide utilities with perverse incentives. If prudency is determined by excluding "sunk" costs and considering only "costs to complete," the incentive would be for utilities to spend as much capital as possible early on since spending as much money as possible upfront would ensure that any remaining capital to be spent could be shown to be cost-effective, regardless

[24] Alders Direct, p. 47.
[25] Alders Direct, Table 9.
[26] Alders Direct, Table 10.

of the total costs of the project. Thus, the utility would no longer have a strong incentive to minimize costs, nor to provide accurate estimates of total costs in CN proceedings.

Third, as discussed above, I conclude that the 2008 EPU CN analysis provides the appropriate review of the prudency of the combined Monticello LCM and EPU. Moreover, based on that analysis, I agree that continued operation of Monticello on a combined basis, including the costs of both the LCM and EPU, is more cost-effective than shutdown and replacement.

4. Incremental Value of EPU

Q. Did Xcel focus its analysis on the incremental cost of the EPU?

A. No. As Mr. Alders stated on page 53 of his Direct Testimony:

> Q. WHY DID YOU NOT FOCUS ON THE INCREMENTAL COST OF THE EPU IN YOUR ANALYSIS?
>
> A. The Company believes that the real value of Monticello is in its continued safe and reliable operation through 2030 and potentially beyond so that we can capture the fuel diversity, environmental benefits and relatively low-cost generation. While the EPU was an important initiative, it must be seen in the context of the overall strategy of maintaining long-term viable generation at the site.

As a result, most of Xcel's analysis is focused on the comparison between the combined Monticello LCM and EPU projects and the shutdown and replacement scenario. Mr. Alders states that the Company did not distinguish between the LCM and EPU in implementation of the overall project.[27]

Q. Why is it appropriate to analyze the incremental cost of the EPU?

A. There are several reasons. First, Xcel requested the CN for the EPU as independent from the LCM. The additional 71 MW was analyzed separately from the life extension of Monticello as acknowledge by Xcel.[28] Three years earlier, in Docket No. E002/CN-05-123, Xcel and the DOC conducted analysis of the cost-effectiveness of the LCM as I noted above. Second, it is clear that Xcel could implement the LCM without also implementing the EPU project.[29] Finally, DOC Witness Dr. Jacobs provides testimony which identifies projects and related costs that were needed only for the LCM and those that were needed only for the EPU.

Q. Please describe Xcel's incremental value of EPU analysis.

A. The incremental value of EPU analysis evaluates the cost-effectiveness of the incremental 71 MW obtained due to the investment in the EPU project as compared to the LCM-only scenario, under which the life of Monticello is extended without the 71 MW uprate. This analysis uses the same Strategist base files used in the hindsight analysis discussed above. In order to perform this analysis, total project costs must be split between the LCM and EPU. DOC Witness Dr. William Jacobs provides testimony regarding the appropriate split of costs between the LCM and EPU.

[27] Alders Direct, p. 52.
[28] *Id.*
[29] Prairie Island EPU CON, Order Terminating Certificate of Need Prospectively at 4, Docket No. E002/CN-08-509 (February 27, 2013).

Q. What cost splits between the LCM and EPU did Xcel analyze?

A. Based on Xcel Witness Mr. O'Connor's testimony, Xcel performed an analysis by allocating 22 percent of total project costs to the EPU and 78 percent to the LCM.[30] Based on the cost split used in the 2008 EPU CN analysis, Xcel also performed an analysis by allocating 42 percent of total project costs to the EPU and 58 percent to the LCM.[31]

Q. What did Xcel conclude based on its analysis?

A. When allocating only 22 percent of project costs to the EPU, Xcel concluded that the EPU was cost-effective. However, when 42 percent of costs were allocated to the EPU, Xcel concluded that the EPU project would not be cost-effective since the net PVSC of the combined EPU/LCM project was $36 million higher than the LCM-only project, as shown in Tables 6-7, below:

Table 6: Xcel Witness Mr. Alders' Direct Table 12 – 22 percent EPU

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$893
Monti Total	$4,266

Monticello LCM Only (w/o EPU) 78%	PVSC Results $millions
Monti Retirement (2031)	$148
LCM+On-Going Capital	$1,057
Monti O&M	$1,954
Monti Fuel	$812
Replacement Energy	$295
Replacement Capacity	$81
Incremental Emissions	$69
Total Retirement Costs	$4,417
Net PVSC Savings	**($151)**

[30] Alders Direct, p. 52-53.
[31] Alders Direct, p. 53.

Table 7: Xcel Witness Mr. Alders' Direct Table 13 – 42 percent EPU

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$893
Monti Total	$4,266

Monticello LCM Only (w/o EPU) 58%	PVSC Results $millions
Monti Retirement (2031)	$148
EPU/LCM+On-Going Capital	$870
Monti O&M	$1,954
Monti Fuel	$812
Replacement Energy	$295
Replacement Capacity	$81
Incremental Emissions	$69
Total Retirement Costs	$4,230
Net PVSC Savings	**$36**

Q. Did you assess Xcel's results?

A. Yes. As I described above in my review of Xcel's hindsight analysis, I requested all of the necessary base files, macros, and spreadsheets from Xcel in order to replicate the modeling and results tables used to create Tables 6 and 7 above. As in the 2008 EPU CN analysis, Xcel appropriately used its September 2008 IRP reply comments Strategist base file updated to reflect the $665 million cost that Xcel estimates for the Monticello LCM/EPU. I made the same change to the capacity of the EPU as discussed above by adjusting the capacity of the Monticello EPU down by 12 MW, to 600 MW, for the years 2010-2013.

I also corrected two errors in the data from which Table 5 and 6 were derived. First, in each table, I corrected an error in the way the replacement capacity costs were calculated, so that O&M costs for Monticello were correctly excluded. Second, for Table 6 (Xcel's Table 13) the revenue requirement for the Monticello LCM-only scenario was different from Xcel's results by $2 million dollars. This difference was due to a mistake in the way Xcel input AFUDC costs in this scenario. I confirmed with

Xcel that each of these changes should be made. The net of these adjustments is shown below:

Table 8: 22 Percent EPU (Corrected Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$889
Monti Total	$4,262

Monticello LCM 78%	PVSC Results $millions
Monti Retirement (2031)	$148
LCM + Ongoing Capital	$1,057
Monti O&M	$1,954
Monti Fuel	$812
Replacement Capacity	$93
Replacement Energy	$295
Incremental Emissions	$69
Total Costs	$4,429
Net PVSC (Benefits)/Cost	**($166)**

Table 9: 42 Percent EPU(Corrected Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$889
Monti Total	$4,262

Monticello LCM 58%	PVSC Results $millions
Monti Retirement (2031)	$148
LCM + Ongoing Capital	$872
Monti O&M	$1,954
Monti Fuel	$812
Replacement Capacity	$92
Replacement Energy	$295
Incremental Emissions	$69
Total Costs	$4,243
Net PVSC (Benefits)/Cost	**$20**

Q. What do Tables 8 and 9 indicate?

A. Table 8 indicates that, when only 22 percent of total project costs are allocate to the EPU, the result is significant PVSC savings. However, Table 9 shows that, when 42 percent of total project costs are allocated to the EPU, the addition of the EPU results in net PVSC costs (more costs than benefits).

Because the assumption regarding the appropriate split between the LCM and EPU is critical in determining the cost-effectiveness of the EPU, I performed additional analyses to show the effect of net PVSC when 60 percent and 80 percent of total project costs are allocated to the EPU. Those results are shown below, showing higher levels of non-cost-effectiveness as more costs are assigned to the EPU component:

Table 10: 60 Percent EPU Hindsight (Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$889
Monti Total	$4,262

Monticello LCM 40%	PVSC Results $millions
Monti Retirement (2031)	$148
LCM + Ongoing Capital	$700
Monti O&M	$1,954
Monti Fuel	$812
Replacement Capacity	$93
Replacement Energy	$295
Incremental Emissions	$69
Total Costs	$4,071
Net PVSC (Benefits)/Cost	**$191**

Table 11: 80 Percent EPU Hindsight (Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$148
EPU/LCM+On-Going Capital	$1,266
Monti O&M	$1,959
Monti Fuel	$889
Monti Total	$4,262

Monticello LCM 20%	PVSC Results $millions
Monti Retirement (2031)	$148
LCM + Ongoing Capital	$511
Monti O&M	$1,954
Monti Fuel	$812
Replacement Capacity	$92
Replacement Energy	$295
Incremental Emissions	$69
Total Costs	$3,881
Net PVSC (Benefits)/Cost	**$381**

Q. Do Tables 7-10 accurately show the net PVSC impact of the EPU?

A. No, additional changes are need. As I discussed above in the hindsight analysis when comparing the combined LCM and EPU to the shutdown and replacement scenario, in my review of the Strategist outputs used to create Tables 12 and 13 of Mr. Alders' Direct Testimony, I concluded that Xcel did not correctly discount the cost streams. As noted above, for costs incurred after 2013, Xcel discounted those costs back to 2013 while simply summing costs incurred prior to 2013, rather than escalating those amounts to 2013 dollars. Thus, Xcel's calculation mixed real and nominal costs as costs incurred prior to 2013 were not escalated to 2013 dollars. Moreover, because the purpose of this analysis is to re-evaluate the decision made in 2008, costs should be discounted back to 2008 dollars. Correcting for these errors results in higher levels of cost-effectiveness for the Monticello EPU than the amounts Xcel calculated, as shown in the corrected tables below:

Table 12: 22 Percent EPU-2008 Base Year (Corrected Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello LCM 78%	PVSC Results $millions
Monti Retirement (2031)	$96
LCM + Ongoing Capital	$683
Monti O&M	$1,283
Monti Fuel	$662
Replacement Capacity	$74
Replacement Energy	$237
Incremental Emissions	56
Total Costs	$3,089
Net PVSC (Benefits)/Cost	**($309)**

Table 13: 42 Percent EPU-2008 Base Year (Corrected Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello LCM 58%	PVSC Results $millions
Monti Retirement (2031)	$96
LCM + Ongoing Capital	$563
Monti O&M	$1,286
Monti Fuel	$582
Replacement Capacity	$74
Replacement Energy	$237
Incremental Emissions	56
Total Costs	$2,893
Net PVSC (Benefits)/Cost	**($112)**

Table 14: 60 Percent EPU-2008 Base Year (Corrected Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommission (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello LCM 40%	PVSC Results $millions
Monti Decommissioning (2031)	$96
LCM + Ongoing Capital	$452
Monti O&M	$1,283
Monti Fuel	$662
Replacement Capacity	$74
Replacement Energy	$237
Incremental Emissions	56
Total Costs	$2,859
Net PVSC (Benefits)/Cost	**($78)**

Table 15: 80 Percent EPU-2008 Base Year (Corrected Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Decommission (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello LCM 20%	PVSC Results $millions
Monti Decommissioning (2031)	$96
LCM + Ongoing Capital	$330
Monti O&M	$1,283
Monti Fuel	$662
Replacement Capacity	$74
Replacement Energy	$237
Incremental Emissions	56
Total Costs	$2,737
Net PVSC (Benefits)/Cost	**$44**

Q. Did you again perform an analysis using the DOC base files to review the incremental addition of the Monticello EPU?

A. Yes. As I did in my analysis comparing the combined EPU and LCM projects to the shutdown and replacement scenario, I used the base Strategist files from the 2008 EPU CN and 2007 IRP, discussed earlier in my testimony, and updated the Department's files to reflect the actual costs and capacity timing of the Monticello LCM and EPU. In other words, I performed the same analysis used for Tables 8-15 above, but I used the DOC base file instead of the Xcel base file. The results of that analysis using Xcel's discounting methodology and discounting to the 2008 base year are summarized below:

Table 16: EPU Split Summary-DOC Base Model – Xcel's Discount Method)

Cost Split		Net PVSC Cost (Benefit) $Millions
LCM	EPU	
20%	80%	$455
40%	60%	$267
58%	42%	$94
78%	22%	($91)

Table 17: EPU Hindsight-2008 Base Year (DOC Base Model – Correct Discount Method)

Cost Split		Net PVSC Cost (Benefit) $Millions
LCM	EPU	
20%	80%	$73
40%	60%	($49)
58%	42%	($160)
78%	22%	($280)

Q. What do you conclude from Tables 16 and 17, compared to Tables 8-15, regarding the cost-effectiveness of the EPU?

A. I conclude that, while the DOC model produces results that show the EPU to be somewhat less cost-effective, generally, than Xcel's model from the 2008 CN proceeding, the modelling results are consistent and show a similar break-even point for the cost-effectiveness of the EPU.

Q. Which base model should the Commission rely on if the model is used as a basis for an adjustment to the amount of costs Xcel is allowed to recover from ratepayers for the Monticello EPU?

A. I conclude that the Commission should rely on Xcel's base model as reflected in Tables 12-15 above. As I stated above, the Commission relied on both base models in granting the 2008 EPU CN. However, Xcel's model contained updated information, and therefore contained the most recent data in the record at the time of the 2008 CN decision

Q. Did you determine that a portion of Xcel's investment in the EPU was not cost-effective?

A. Yes. DOC Witness Dr. William Jacobs provides testimony supporting an allocation of 85.7 percent of costs to the EPU. Thus, to determine what portion of the capital investment for the EPU is above the cost-effective level, I calculated the break-even point at which the allocation of cost to the EPU provides costs and benefits that are approximately equal, as shown in Tables 18 and 19, below:

Table 18: 72 Percent EPU-2008 Base Year (Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello LCM 28%	PVSC Results $millions
Monti Retirement (2031)	$96
LCM + Ongoing Capital	$379
Monti O&M	$1,283
Monti Fuel	$662
Replacement Capacity	$74
Replacement Energy	$237
Incremental Emissions	56
Total Costs	$2,785
Net PVSC (Benefits)/Cost	**($5)**

Table 19: 73 Percent EPU-2008 Base Year (Xcel Base Model)

Monticello Life Extension + EPU	PVSC Results $millions
Monti Retirement (2031)	$96
EPU/LCM+On-Going Capital	$818
Monti O&M	$1,286
Monti Fuel	$582
Monti Total	$2,781

Monticello LCM 27%	PVSC Results $millions
Monti Retirement (2031)	$96
LCM + Ongoing Capital	$373
Monti O&M	$1,283
Monti Fuel	$662
Replacement Capacity	$74
Replacement Energy	$237
Incremental Emissions	56
Total Costs	$2,779
Net PVSC (Benefits)/Cost	**$1**

Q. What does the information in Tables 18 and 19 indicate?

A. Tables 18 and 19 indicate that an allocation of 73 percent of costs to the EPU is the first whole number percentage that results in a net PVSC cost for the Monticello EPU. Thus, the portion of the EPU that is not cost-effective is the difference between 73 percent and the 85.7 percent of total cost attributable to the EPU as supported by

DOC Witness Dr. Jacobs. Table 20 shows the calculation of the portion of the EPU investment that is above the cost-effective level.

Table 20 : Difference between 73 Percent and 85.7 Percent Assignment of Costs to the EPU(Amount Not Cost-Effective)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Total EPU/LCM Costs	100%	$796	$14	$6,987	$15,705	$73,560	$118,709	$76,079	$173,887	$47,041	$152,140	$664,918
EPU Cost-Effective Amount	73%	$581	$10	$5,101	$11,465	$53,699	$86,658	$55,538	$126,938	$34,340	$111,062	$485,390
Percent EPU	85.7%	$682	$12	$5,988	$13,459	$63,041	$101,734	$65,200	$149,021	$40,314	$130,384	$569,836
Not Cost-Effective EPU		**$101**	**$2**	**$887**	**$1,995**	**$9,342**	**$15,076**	**$9,662**	**$22,084**	**$5,974**	**$19,322**	**$84,445**

Q. Do your conclusions mean that if the actual costs of the EPU were accurately estimated at the time of the 2008 EPU CN, the Department would have recommended that the CN for the EPU not be granted?

A. Yes. If the actual costs and timing of the EPU had been known, other alternatives would have been more cost-effective. Attached as DOC Exhibit No.___ (CJS-7) is a comparison of expansion plans, with and without the addition of the EPU.

Q. Do you recommend that the portion of EPU cost above the cost-effective level, as shown in Table 19, be disallowed?

A. Nancy Campbell provides the DOC recommendation on cost recovery. Mr. Campbell provides an analysis of the impacts of the proposed adjustment on Xcel's Minnesota Jurisdiction, the allowance for funds used during construction (AFUDC), and impact on the revenue requirement, as well as a review of past Commission actions regarding costs that exceed CN estimates.

Q. Did Xcel also perform an implementation analysis of the incremental 71 MW EPU addition?

A. Yes. Similar to the implementation analysis discussed above, when Xcel compared continued operations at Monticello to shut down and replacement, Xcel analyzed the cost-effectiveness of proceeding with the EPU in each year 2008-2012. However, in this case, Xcel only included an analysis which incorporated sunk costs. Using allocations of total cost to the EPU of 22 percent and 42 percent, Xcel concluded that continuation of the project was cost-effective in each year as shown in Table 16 of Xcel Witness Mr. Alders' testimony.

Q. Do you agree that Xcel's analysis provides a reasonable basis to determine the prudency of the Monticello EPU?

A. No. First, I note that I did not review the individual Strategist files used the support Table 16 of Mr. Alders testimony, because I do not agree that this analysis provides a basis for determining prudency. Xcel's analysis only relies on the remaining "to-go" amount of capital. Thus, capital spent prior to the year of analysis is removed from the cost of Monticello. As I have previously discussed, prudency should be determined based on the assumptions relied on at the time of the 2008 Monticello EPU CN updated for the actual costs and timing of the Monticello LCM and EPU. As I concluded above, it is important that Xcel provide accurate estimates of project costs for projects it proposes in CN proceedings. Xcel implementation analysis, whether applied to the EPU or the combined EPU and LCM projects, would provide utilities with perverse incentives. If prudency is determined by excluding sunk costs, the incentive is for utilities to spend as much capital as possible upfront. This would ensure that any remaining capital to be spent would be cost-effective regardless of the total costs of the project. Thus, the utility would no longer have a strong incentive to provide accurate cost estimates of the total project costs in the CN. As comparison to alternatives based on relative costs in a critical part of any CN analysis, this loss of incentive to provide accurate estimates of project costs would adversely affect the integrity of the CN process.

V. CONCLUSION

Q. Please summarize your conclusions.

A. Based on my analysis, I conclude that:

- To determine prudency, the appropriate analysis should be based on assumptions relied on at the time of the 2008 Monticello EPU CN, updated to reflect the actual costs and timing of the Monticello LCM and EPU.
- The Commission relied on both DOC modeling and Xcel modeling in granting the 2008 EPU CN. Both models produced similar results, indicating that the 2008 EPU CN was cost-effective in 2008. Xcel's model contained updated information, and therefore contained the most recent data in the record at the time of the 2008 CN decision.
- Xcel's base model updated in its September 2008 IRP reply comments in the EPU CN proceeding for the cost and timing of the Monticello LCM and EPU should be relied on to determine prudency.

- When 73 percent of total costs are allocated to the EPU, the costs and benefits are approximately equal. Therefore, costs over that amount represent investment that was not cost-effective.
- The difference between the 73 percent and the 85.7 percent responsibility of the EPU for costs is $84,445 million on a total Company basis.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF A COMMISSION INVESTIGATION INTO XCEL ENERGY'S MONTICELLO LIFE CYCLE MANAGEMENT AND EXTENDED POWER UPRATE PROJECT AND REQUEST FOR RECOVERY OF COST OVERRUNS	MPUC Docket No. E002/CI-13-754 OAH Docket No. 48-2500-31139

DIRECT ATTACHMENTS OF CHRISTOPHER J. SHAW

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

JULY 2, 2014

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- Xcel Wind Acquisition, Docket Nos. E002/M-13-603, E002/M-13-716
- Xcel Energy Competitive Resource Acquisition Process, Docket No. E002/CN-12-1240
- Xcel Energy Power Purchase Agreement (PPA), Docket No. E002/M-11-713
- Interstate Power and Light Rate Case – Wind Resource Costs, Docket No. E001/GR-10-276
- Xcel's Notice of Changed Circumstances regarding an Extended Power Uprate at the Prairie Island Nuclear Generating Plant, Docket No. E002/CN-08-509
- Xcel Energy Transmission Cost Recovery Riders, Docket Nos. E002/M-13-1179, E002/M-12-50 and E002/M-10-1064
- Otter Tail Power Company Transmission Cost Recovery Rider, Docket No. E017/M-10-1061
- Xcel Energy Merricourt and Nobles Wind Farm Projects, Docket No. E002/M-08-1437
- Missouri River Energy Services – Integrated Resource Plan, Docket No. ET10/RP-10-735
- CapX Transmission Lines – Certificate of Need, Docket ET2,E002/CN-06-1115

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☒ **Public Document**

Xcel Energy			
Docket No.:	E002/CI-13-754		
Response To:	Department of Commerce	Information Request No.	94
Requestor:	Nancy Campbell, Chris Shaw		
Date Received:	April 25, 2014		

<u>Question:</u>

Reference: Docket Nos. E002/CN-05-123 and E002/CN-08-185

Based on DOC's review of the two above referenced certificate of need (CN) dockets, the Department considers the below numbers (including pages references to CN's) to be the breakout of costs for Monticello for CN purposes.

a) Please confirm if Xcel agrees with the numbers below, or if not please explain the Company's disagreement with the numbers.
b) Are the ISFSI costs included in the Company's final cost for the Monticello LCM/EPU of $664,918,471 (Scott Weatherby's Schedule 3, Appendix A-1) as of August 2013, excluding AFUDC and removal costs?
c) Are the ISFSI costs included in the Company's filing for the Monticello Cost Overrun (E002/CI-13-754)? If no, should these costs be included? Please explain your response.

Monticello Life Cycle Management (LCM)	$135 million
Monticello Extended Power Uprate (EPU)	$133 million
Independent Spent Fuel Storage Installation (ISFSI)	$ 55 million

1. Xcel's Petition, dated February 14, 2008, in Docket No. E002/CN-08-185 (Monticello EPU), page 1-6:

   The total project cost for the power uprate will be approximately $104 million. The final cost will depend upon whether a new steam dryer is required.[2] If required, the new steam dryer will add $29 million to the project for a total project cost of $133 million.

[2] Equipment has been installed to assess the need for the new steam dryer. The decision will be made after analyzing data obtained following startup after the 2009 uprate modifications are complete.

2. Xcel's Petition, dated January 18, 2005, in Docket No. E002/CN-05-123 (Monticello LCM), states at page 1-12:

   Based on the plant assessment and industry experience in the relicensing process, Monticello identified and included approximately $135 million in investments above normal annual investments that may occur in the future as part of the cost benefit analysis associated with license renewal.

3. Xcel's Petition, dated January 18, 2005, in Docket No. E002/CN-05-123 (Monticello LCM), states at page 1-12:

   The estimated installed cost of the ISFSI in 2004 dollars is $55 million. The estimate includes the following component costs:

Regulatory Process	$2.0 M
Engineering and Design	$12.0 M
Plant Upgrades	$4.0 M
ISFSI construction	$3.5 M
30 canisters and storage	$26.0 M
Canister Loading Campaigns	$7.5 M

<u>Response</u>:

a) We agree that these are numbers that were presented in those two separate Certificate of Need proceedings.

   However, we note that the ISFSI Certificate of Need pertained to the on-site fuel storage facility itself, not life-cycle management activities that would be needed if Monticello's operating license was extended. In the 2005 ISFSI Certificate of Need filing, we requested authority to install the on-site fuel storage facility whether or not Monticello's operating license was extended because we identified a need for on-site storage even if Monticello were to have been shut down at the end of its initial operating license in 2010. The LCM activities described in the ISFSI Certificate of Need filing were representative of the types of activities we anticipated would be needed if the NRC extended our operating license and we anticipated the potential for additional items as new information became available. (*See* ISFSI CON Application, p. 5-13.)

We also note that in the 2008 EPU Certificate of Need filing, the Company provided economic inputs to the cost benefit analysis for the EPU project, that included an updated estimate of LCM capital spending (above normal annual investments) of approximately $170 million (including the addition of the Steam Dryer) along with the $133 million for the uprate. The remainder of the initial $320-346 million modeled in that docket was built through escalation of the costs over time. Those amounts were based on additional project design and scoping in 2007.

In the Company's 2011 test year rate case (E002/GR-10-971), we updated costs for the total LCM/EPU Project of about $361 million, including both uprate and life-cycle management costs, through 2011. (Koehl Direct, p. 31.) In rebuttal testimony, we further updated the estimate at $399.1 Million for the jointly-managed and implemented LCM/EPU Program. (Koehl Rebuttal, p. 15.) In November 2011, our prior Chief Nuclear Officer, Mr. Koehl, testified at hearing that the final cost of the Project was expected to be approximately $550-600 million. In our 2012 rate case (Docket E002/GR-12-961) the Company further updated the estimated cost to $587 million. The Company had spent approximately $494 million on the project as of August 31, 2012. (O'Connor Direct p. 17.) We further updated that estimate in our response to Information Request DOC-160, in the rate case to approximately $640 million. In the current rate case, we provided our latest estimate of the overall LCM/EPU Project costs as $655 million.

b) No. The direct ISFSI costs (for additional dry cask storage of spent nuclear fuel) has never been part of either the estimated or actual Monticello LCM/EPU Project costs, from the inception of the Project. The ISFSI work was its own separate project based on the Commission's granting of the Certificate of Need in Docket E002/CN-05-123. ISFSI additional dry cask storage of spent nuclear fuel construction work has always been planned, managed, and constructed separately from LCM/EPU Project work. The Company separately considered and approved the ISFSI work as part of the decision to seek an extended operating license. In addition, on page 5-15 of the ISFSI Certificate of Need Application, we note that $55 million for the ISFSI project is included as a cost in the Strategist Model that was constructed to compare the cost of Monticello to other alternatives. In addition, as a separate item, on pages 5-12 and 5-13 of the ISFSI Certificate of Need Application we also included $135 million for LCM upgrades as a separate amount.

c) No. While the ISFSI costs are referenced in the 2005 certificate of need, they have not been treated as part of either the LCM or EPU activities at the plant. The ISFSI was needed irrespective of whether Monticello's operating license was extended or whether the Company had increased the capacity of the plant. As noted on page 1-10 of the ISFSI Certificate of Need Application: "The need for dry on site storage is not eliminated if the plant does not operate beyond 2010. If a Certificate of Need were not granted, the Monticello plant would shut down by the end of 2010. In order to decommission the plant, spent fuel would have to be removed from the reactor and spent fuel pool. A dry storage facility utilizing 40 storage containers would be needed in order to decommission the plant." Thus, the ISFSI has never been considered a cost of continued operations. The costs of potential LCM upgrades necessary to support an extended operating license were treated separately from the costs of the ISFSI itself.

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4. Modeling and Preferred Plan

- *The Company proposes a Preferred Plan that meets the projected need, maintains fuel diversity, addresses the state's environmental leadership and provides reasonable costs to consumers. Our Preferred Plan relies on increased wind and DSM, expanded output from our existing nuclear and coal-fired plants, purchases from Manitoba Hydro, and new peaking and intermediate resources to meet our customers' growing needs.*
- *Scenario analysis demonstrates that the Preferred Plan is robust under various assumptions and forecast uncertainties.*

Strategist Resource Planning Model

This chapter introduces the Strategist resource planning software, evaluates the resources available for capacity expansion, and presents the details of the Company's preferred Plan. Xcel Energy has used the "Strategist" model in our Resource Plans since 2000. Strategist is used to estimate the cost of resource expansion plans and to evaluate specific capacity alternatives. In prior Resource Plans, Strategist played a central role in helping identify and refine resource options. In this Plan, Strategist's role continues to be important; however, major resource decisions in this Plan result from only the RES, the conservation/DSM goals, the new limits on greenhouse gas emissions -- and Xcel Energy's commitment to implement these bold initiatives. For example, given the likelihood of future carbon regulation, we have only modeled a future coal-based resource option that includes carbon capture and storage.

The Strategist Model is also used to test the reasonableness and the robustness of this resource plan. We work to carefully and accurately characterize our current system and to develop assumptions that best reflect our expert opinion of likely future conditions. Strategist, in turn, helps with the analysis of the myriad of options and "what if" scenarios that must be a part of a robust planning regime.

The model consists of four primary components.

- *Load Module* that contains Xcel Energy's load forecast, load management, and conservation programs. This module produces long-range estimates of the Company's net energy requirements and peak capacity requirement.
- *Generation Module* that contains the operating costs and performance characteristics for our thermal units, renewable resources, and transactions. This module uses an hourly dispatch simulation to estimate how demand will be met and what the associated costs and emissions will be.
- *Capital Project Module* that estimates the revenue requirement for capital projects such as new generating resources. This module keeps track of rate base, depreciation, taxes, and rate of return for existing and future capital projects.
- *Expansion Planning Module* that uses a dynamic programming algorithm to derive the least cost expansion plan possible. This module calculates the customer and societal costs for thousands of different resource combinations to arrive at the least cost plan.

For each expansion plan, Strategist calculates fuel consumption, fuel costs, O&M costs, emission rates, capital costs, and total revenue requirement. The total system costs are reported as the net present value of revenue requirements or "PVRR." This value is the sum of all operating, depreciation, return on rate base, and tax costs, less any revenues from sales discounted back to 2008 using the Company's most recently authorized weighted after tax cost of capital of 7.42%.

By using Strategist, we can demonstrate to the Commission, Department and other stakeholders, that our Plan will meet customer needs under a variety of conditions at a reasonable cost. Strategist tests our Plan under a number of possible futures and allows us to select a robust Plan that reflects our vision and meets all of our current and expected future legal and regulatory requirements.

Baseline Assumptions

Although the planning period in this report covers 2008-2022, Strategist analysis covers 2008-2047 and our reported PVRR values correspond to this time period. The longer time interval allows us to better estimate the costs and benefits of the long-lived resources proposed in this plan. Other important assumptions include:

Forecast

- We plan to meet the 90% probability level of forecasted peak demand, and the 50% probability level of forecasted energy requirements. The forecast has been offset by our DSM goal of 1.1% energy savings.

Existing Fleet

- Cost and performance assumptions are consistent with historical data.
- Costs are escalated based on corporate estimates of expected inflation rates.
- Continued operation of our Sherco and King generating stations throughout the study period.
- Retirement of our Prairie Island nuclear generating station at the end of its proposed license renewal (2034, 2035), and retirement of Monticello at the end of its current license (2030).
- Retirement of other facilities at their current expected end of life if within the resource planning period, unless we have specifically included costs of life extension.
- Continuation of our existing power purchase contracts until their contractual termination dates.
- Continued operation of Xcel Energy's hydroelectric resources based on historical performance.

Renewable Energy

- Addition of renewable energy resources capable of generating at least 11,500 GWh of eligible energy by 2020 in order to meet our requirement to generate at least 30% of our energy from renewables by that date.
- Accreditation of wind resources in accordance with MAPP rules and based on historical performance (12.5% average), and capacity factors based on hourly wind speed data from the 2006 Minnesota Wind Integration Study.
- Extension of the Federal Production Tax Credit through 2015.
- Additional ancillary service charges for wind based on the 2006 Minnesota Wind Integration Study.

Emissions

- Emission rates for existing and planned resources consistent with historical and expected performance.
- Cap and trade permit systems for SO_2, NOx, and Mercury, consistent with the Clean Air Intersate Rule ("CAIR") and CAIRM
- \$20/ton charge for CO_2 starting in 2010 and escalating at 2.5% per annum with alternative scenarios showing a \$9/ton value and a \$40/ton scenario
- Externality scenario analysis uses the Commission's updated high and low externality value. In these scenarios, our \$20/ton value for CO_2 replaces the Commission's value but the Commission's value for NOx is not used in favor of the forecasted value of NOx permits under CAIR.

Strategist uses generically defined resources to meet future demand when existing resources fall short. The Company used the following generic resources as model inputs for this Resource Plan:

- 160 MW gas-fired Combustion Turbine peaking unit (CT)
- 600 MW gas-fired Combined Cycle intermediate unit (CC)

- 500 MW Super Critical Pulverized Coal base load unit with partial carbon sequestration (SCPCwSEQ)
- 100 MW Wind project (Wind)

The CTs become available for inclusion in the expansion plan starting in 2012, CCs 2013, SCPC 2015, and Wind 2009. Cost and performance data for these units are based on a consultant's estimates and internal company data.

Reference Case

To develop the Company's preferred resource expansion plan, we first construct a Reference Case to provide a basis for comparison. The Reference Case uses our baseline assumptions, including the wind that will be needed to meet the RES. It does not include upgrades at the Sherco and Nuclear Plants or the extension of the Manitoba Hydro Contract. The Reference Case , however, does assume that Prairie Island is extended through 2033 and 2034. Although we will be asking for specific approval in this plan and later filings to extend the licenses at Prairie Island, we have assumed life extension for the reference case because the impact of removing Prairie Island from the system dwarfs the effect of all other resources we are considering for inclusion in the preferred plan combined. In Chapter 8 of this plan, we will analyze the effect of Prairie Island shutdown and demonstrate that life extension is in the public interest.

The expansion plan resulting from the Reference Case includes no new base load plants, 3,800 MW of gas fired units, and 2,400 MW of generic wind additions. Higher capital costs and high penetrations of wind energy combine to make base load alternatives, such as coal, economically unattractive. Gas units are the only other generic options available to the model because wind additions are "hard coded" into Strategist to ensure all expansion plans comply with the RES. The RES requires us to maintain a wind penetration of 25% of retail energy, which is the highest penetration of wind energy required in the country and the limits of what was studied in the Minnesota Wind Integration

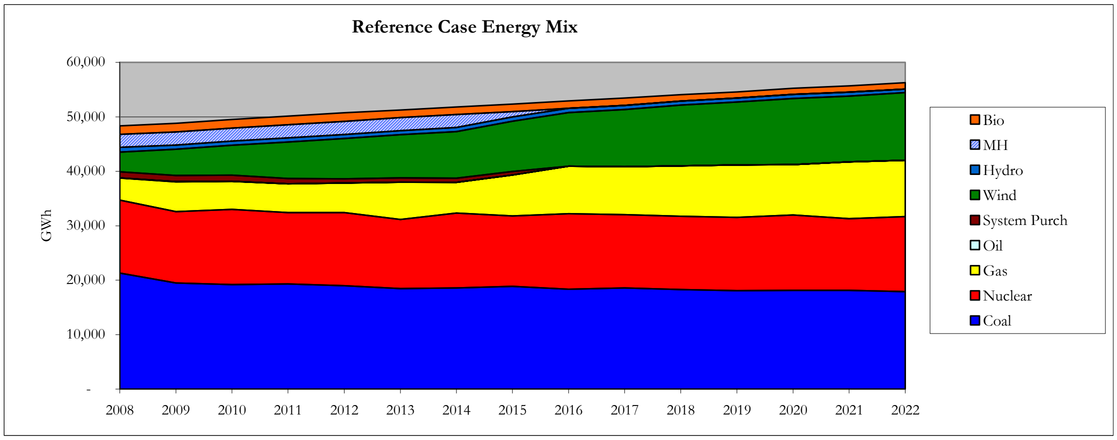
Study. Because we are still unsure about the operational impacts of this amount of wind on our system, we did not permit the reference model to select any more wind above the RES requirements. Table 4-1 summarizes the reference case. Figures 4-1 and 4-2 show the reference case energy mix and CO_2 emissions respectively.

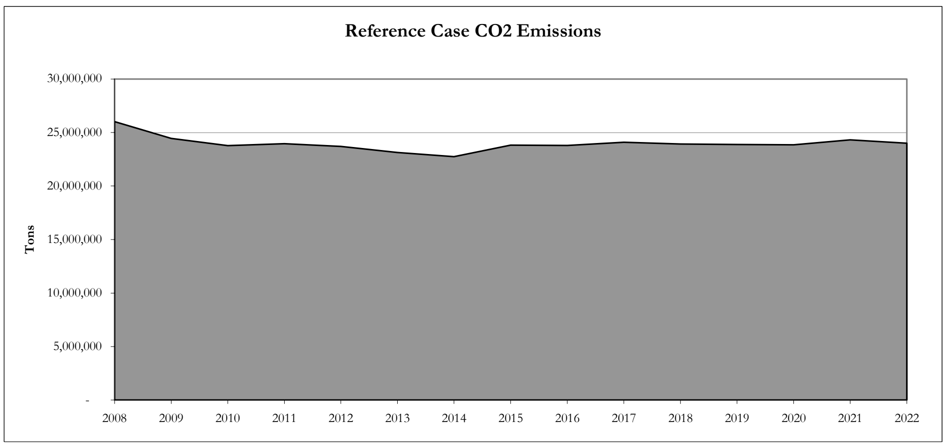
Table 4-1

Reference Case **PVRR** **$62,679,487** **($000)**

	Planned Additions	Combined Cycle	Combustion Turbine	Pulverized Coal With CO2 Sequestraition	Wind Additions
2008		High Bridge CC 624MW			
2009	Rahr 12MW	Riverside CC 508MW			100MW CBED 209MW Grand Meadows 100MW
2010					200 MW
2011			160 MW		200MW CBED 200MW
2012			640 MW		200 MW
2013			160 MW		200 MW
2014		600 MW			200 MW
2015		600 MW			200 MW
2016		600 MW			200 MW
2017					200 MW
2018		600 MW			200 MW
2019					200 MW
2020					200 MW
2021					
2022		600 MW			100 MW

Figures 4-1 and 4-2





Sensitivity Analysis

To determine how changes in our assumptions impact the costs or characteristics of different resource plans, we examine our plans under a number of scenarios. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we may propose an expansion plan that is less sensitive to assumption changes, but slightly more costly in the baseline scenario. For this Resource Plan, we tested the following scenarios.

- *Load.* The base forecast (unadjusted for DSM) has an average energy growth rate of 1.14%. The energy growth rate was adjusted down to average 1% and was also adjusted up to average 1.3%.

- *Fuel Cost*. The cost of natural gas, coal, and nuclear fuel were all independently adjusted up and down by 20%.
- *Externalities*. The Commission's low and high externality values were added to test the societal impacts of each expansion plan. However in place of the Commission's values for NOx the forecasted CAIR permit price was used and the Company's baseline CO_2 hedge value of $20/ton was used in place of the Commission's CO_2 value.
- *CO_2 Values*. The CO_2 hedge values were varied down to $9/ton and up to $40/ton.
- *MISO*. Due to the unpredictability of future market conditions, Xcel Energy models itself as a stand-alone system without additional purchases and sales from the MISO day two market. In our sensitivity analysis, Strategist's Network Economy Interchange ("NEI") submodule was activated to simulate how the system might interact with the rest of MISO. However, this sensitivity requires highly speculative assumptions about supply and demand conditions in the rest of the market. The Company recommends that these results should be viewed as an estimate of one possible outcome, but not a precise prediction of what will occur in the future.
- Capital Cost Escalation – The base assumption in Strategist is that the cost of capital projects will increase at 1.88%. 3% and 5% cost escalation scenarios were also run to evaluate expansion plan sensitivity to escalation assumptions.

Strategist does have some limitations. Although it uses hourly information, it is not a chronological model. Hourly patterns for energy demand are rearranged into load duration curves and thermal dispatch simulations are based on these curves. This allows us to quickly simulate several years of operation on our system, but the model loses the ability to capture some operational detail, such as the ramp rates on our generating units. This makes it difficult for us to use the model to evaluate the benefits of quick start combustion turbines. Also, Strategist uses a simplified approach to modeling load and wind patterns.

Instead of using an hourly pattern that covers every hour in an entire month, we model a typical week in that month that the model repeats several times to simulate the entire month.

Additional Expansion Plan Alternatives

In developing our preferred plan, we have identified a number of resources in addition to our generic resources that could be added to our system to meet future resource needs. Many of these resources, such as our Sherco and Nuclear upgrades and the Manitoba Hydro contract, were discussed in our 2004 Resource Plan. Others, such as Black Dog repowering, are new to this plan.

Life Extension Projects

The Company has the opportunity to extend the life of some of its peaking facilities by making relatively modest capital investments. Key City, Granite City, Blue Lake, Wheaton 5&6, and French Island 3&4 are all candidates for life extension. This option will reduce the need for new gas fired generation by 556 MW during the planning period and will cost approximately $166 million or $299/kW, as opposed to $578/kW for a new combustion turbine.

Sherco Upgrades

Various options for increasing capacity and improving efficiency at the Sherburne County coal plant have been identified. The preferred option will add approximately 80 MW and cost $238 million.

Monticello Upgrade

An opportunity to increase capacity is also available at the Monticello nuclear facility. This option will add 68 MW and cost $82 million.

Prairie Island Upgrades

The upgrade option at Prairie Island will add 170 MW and cost $291 million.

Manitoba Hydro

While our Resource Plan no longer indicates a need for additional base load resources beyond investments in our existing fleet, it does indicate substantial need for peaking and intermediate resources. Our analysis confirms that a purchase from Manitoba Hydro is a cost-effective resource and fills an important need for intermediate resources during the planning period. Because the underlying nature of the identified need has substantially changed from the 2004 Resource Plan, we propose to close the on-going proceeding and initiate a new proceeding pursuant to the two-track resource acquisition process approved by the Commission in conjunction with our prior Plan. We believe this new process would be more efficient were we to complete contract negotiations and initiate the new proceeding with the filing of a proposed purchased power agreement. We expect to make such a filing by Fall 2008. We present in greater detail our proposal for addressing the ongoing proceeding under separate cover, as required by the Commission's Order in Docket Nos. E-002/RP-04-1752, E-002/M-07-2, and E-002/CN-06-1581.

Black Dog Repowering

With Black Dog units 3 and 4 nearing the end of their book lives, we have identified a possible opportunity to retire those units and replace them with natural-gas fired generation, similar to our MERP conversions at High Bridge and Riverside. This could be done in the 2013-2015 time frame. Further studies are needed to identify the exact costs and configurations of such a proposal, which is currently modeled based on our estimate of generic costs.

LMS 100

The generic combustion turbine modeled in Strategist is based on a GE F type unit. These are reliable low cost units that are currently used in Xcel Energy's system and will continue to play an important role. However, these units do not have quick start capability and are only able to be run on natural gas unless additional investments are made to permit them to run on fuel oil. The

Company believes that the addition of one or more LMS 100s (or similar units) would significantly improve system reliability. These units' ability to start quickly is expected to become increasingly valuable as wind resources are added to our system. In addition to natural gas, LMS 100s can be run on fuel oil or bio-diesel. However, these units are more costly than F type machines, and it is difficult to quantify their economic value to system operation until we gain more experience with the operation of large amounts of wind energy on our system.

Demand-Side Management

We assumed, as our baseline, that we would achieve a 1.1% reduction in retail sales due to DSM programs. An alternative 1.3% scenario that will reduce peak demand by 323 MW by the end of the planning period and would increase revenue requirements by $799 million or an equivalent capacity cost of $2,476/kW.

Alternatives Analysis

To evaluate the cost effectiveness of these alternatives, each was added separately to the reference case in the year that the resource is proposed. Strategist then calculated a least-cost expansion plan for each alternative. Finally, each expansion plan was evaluated using scenario analysis.

Table 4-2

Reference Case PVRRs and Alternative PVRR Differences ($millions)

	Base Assumptions	Low Load	High Load	Coal + 20%	Gas +20%	Nuclear+20%	Coal-20%	Gas-20%	Nuclear-20%	Externalities High	Externalities Low	CO_2 \$9	CO_2 \$40	MISO ON	Capital Cost ecsl 3%	Capital Cost escl 5%
Reference Case	61,843	60,604	63,374	62,772	64,580	62,183	60,901	59,898	61,572	61,985	62,049	57,351	70,011	61,695	63,273	66,604
Ref. Case plus Peakers	(353)	(348)	(353)	(350)	(375)	(349)	(350)	(327)	(349)	(350)	(350)	(348)	(379)	(341)	(334)	(295)
Ref. Case plus Sherco Upgrades	(86)	(74)	(100)	(73)	(170)	(86)	(99)	(20)	(86)	(85)	(85)	(114)	(53)	(45)	(87)	(157)
Ref. Case plusMonticello Upgrade	(197)	(179)	(216)	(202)	(272)	(185)	(193)	(140)	(208)	(198)	(199)	(158)	(295)	(167)	(199)	(201)
Ref. Case plus Prairie Island Upgrades	(523)	(496)	(546)	(528)	(647)	(503)	(508)	(406)	(533)	(521)	(522)	(433)	(698)	(478)	(510)	(488)
Ref. Case plus Manitoba Hydro	(170)	(157)	(178)	(169)	(273)	(166)	(162)	(73)	(166)	(168)	(168)	(118)	(269)	(133)	(160)	(142)
Ref. Case plus Black Dog	(263)	(295)	(209)	(315)	(38)	(259)	(188)	(447)	(259)	(274)	(280)	(159)	(480)	(342)	(290)	(357)
Ref. Case plus LMS 100	107	108	107	107	100	107	107	116	107	107	107	109	90	115	104	96
Ref. Case plus DSM 1.3%	(642)	(644)	(634)	(647)	(811)	(642)	(635)	(541)	(642)	(643)	(644)	(556)	(782)	(630)	(669)	(726)

Our analysis shows that nearly all of the resources we evaluated have lower PVRRs than the reference case under most scenarios analyzed. The scenario where PVRR differences are the narrowest is the one where we assumed that gas prices would be 20% lower than our forecast; we do not consider this a likely scenario in the future.

The only alternative that does not result in a lower PVRR generally is the LMS 100. Because of the higher capital costs, we predicted that the LMS 100 would appear slightly more expensive than the GE F type CT in Strategist. This is because Strategist is not a chronological model and cannot capture the quick start benefits of the LMS 100. Also, Strategist cannot effectively model the benefits of the LMS 100s dual fuel capability, because it assumes that gas is always available. In reality, natural gas used for electric generation is sometimes curtailed in favor of residential and industrial use. In such situations, an LMS 100 would still be able to provide peaking capacity to the system and provide a significant improvement to reliability in the winter months.

Preferred Plan

Our Preferred Plan assumes that we extend the lives of our peaking facilities, complete the Sherco and Nuclear Uprates and extend our contract with Manitoba Hydro. We have also included the possibility of repowering Black Dog in our preferred plan, although further study will be needed to determine the actual costs and benefits of this proposal and whether it is the appropriate course of action. The Preferred Plan reduces the Reference Case PVRR by $1,788 million. The Plan also reduces carbon emissions by more than 20% from our 2005 levels and maintains the Company's fuel diversity.

Table 4-3

Preferred Plan **PVRR** **$60,054,763** **($000)**

	Planned Additions	Combined Cycle	Combustion Turbine	Pulverized Coal With CO2 Sequestraition	Wind Additions
2008		High Bridge CC 624MW			
2009	Rahr 12MW	Riverside CC 508MW			100MW CBED 209MW Grand Meadows 100MW
2010					200 MW
2011	Monticello 68MW		160MW		200MW CBED 200MW
2012	Sherco 2 30MW Sherco 3 10MW		320 MW		200 MW
2013	Sherco 1 44MW PI 1 83MW	Black Dog 300MW			200 MW
2014					200 MW
2015	Manitoba Hydro 375MW Manitoba Hydro DIV 350 PI 2 87MW	600 MW			200 MW
2016					200 MW
2017					200 MW
2018		600 MW			200 MW
2019					200 MW
2020					200 MW
2021	Manitoba Hydro 125MW				
2022		600 MW			100 MW

Appendix B
Strategist Modeling Assumptions

The assumptions used in Strategist were the most up to date available in October & November 2007 and were intended to provide accurate measure of Xcel Energy's generation fleet and associated costs.

Existing and Generic Thermal Units
Xcel Energy has about 50 existing thermal units in South Dakota, Minnesota, and Wisconsin. In Strategist the maximum capacity input is the maximum energy a unit can produce in one hour. The value used was selected to reflect the Company's best estimate of each unit's maximum dependable capability. The retirement dates in the table are based on our Preferred Plan, which assumes life extensions of our peaking facilities. For the generic units added in the Preferred Plan the maximum capacity and accredited capacity data is based on a proprietary study done for the Company. The July and January accredited capacity is based on Uniform Rating of Generating Equipment (URGE) testing done by the Company.

Unit	Maximum Capacity	July Accredited Capacity	January Accedited Capacity	Retirement Date	In-service Date/First Yr Available
***COAL**					
AS King 1	558	580	553	2047	
BlackDog 3	86	107	107	2011	
BlackDog 4	165	175	175	2011	
Rivside 7	142	145	150	2008	
Rivside 8	217	231	235	2008	
Sherco 1	697	701	701	2100	
Sherco 2	682	706	706	2100	
Sherco 3	504	522	522	2100	
***NUCLEAR**					
Monti 1	594	568	594	2029	
P Island 1	549	524	549	2033	
P Island 2	546	520	546	2034	
***BIOMASS**					
Bayfront 4	20	21	19	2023	
Bayfront 5	20	24	17	2023	
Bayfront 6	27	28	28	2020	

Fch Isld 12	16	28	28	2023	
Redwing 12	17	21	22	2012	
Wilmarth 12	17	19	20	2012	
***GAS CTs**					
Anson 2	128	107	128	2021	
Anson 3	128	108	128	2021	
Anson 4	180	159	180	2035	
Bluelake 7	186	159	186	2035	
Bluelake 8	183	158	183	2035	
Flambeau 1	17	15	20	2012	
Granite 1	17	15	19	2018	
Granite 2	17	15	20	2018	
Granite 3	18	16	20	2018	
Granite 4	17	14	18	2018	
Inverhil 1	68	60	71	2050	
Inverhil 2	65	57	71	2050	
Inverhil 3	66	59	71	2050	
Inverhil 4	67	61	71	2050	
Inverhil 5	65	58	69	2050	
Inverhil 6	68	60	71	2050	
Key City 1	17	15	20	2013	
Key City 2	17	15	20	2013	
Key City 3	17	16	20	2013	
Key City 4	17	16	20	2013	
Wheaton 1	66	56	69	2050	
Wheaton 2	75	65	80	2050	
Wheaton 3	66	57	70	2050	
Wheaton 4	68	56	68	2050	

Unit	Maximum Capacity	July Accredited Capacity	January Accedited Capacity	Retirement Date	In-service Date/First Yr Available
***GAS CCs**					
BlkDg CC 52	290	257	306	2032	
HB_CC 1	312	262	0	2047	
HB_CC 2	312	262	0	2047	
RS_CC 1	254	0	0	2047	
RS_CC 2	254	0	0	2047	
BLKDG CC 67	300	252	300	2100	2013
***OIL**					
Bluelake 1	51	41	54	2030	
Bluelake 2	51	42	54	2030	
Bluelake 3	51	40	53	2030	
Bluelake 4	61	50	64	2030	
Fch Isld 3	82	69	86	2023	
Fch Isld 4	82	70	88	2023	
Wheaton 5	74	62	75	2035	
Wheaton 6	75	60	75	2035	
InvrD78 78	4	3	4	2047	
Diesels 1	10	6	8	2047	
***PURCHAS 1**					
St. Paul 1	25	25	25	2023	
VirgHibb 1	35	35	35	2026	
Fibromin 1	50	50	50	2028	
Invenerg 1	357	301	0	2025	
2011CT 1	160	143	168	2047	2011
LSCotGrv 1	262	244	275	2027	
CalpMnkt 1	365	311	361	2025	
***GENERICS**					
100_LMS 1	96	82	96	2047	2012
160_CT 1	160	136	160	2047	2012
627_CC 1	627	564	627	2047	2015
500_PC 1	500	475	500	2047	
600_IGCC 1	600	510	600	2047	2015
1000_Nuc 1	1000	960	1000	2047	
IGCCwSEQ 1	600	600	600	2047	
SCPCwSEQ 1	420	399	420	2047	2015

Transactions/PPAs

	Maximum Capacity (MW)	Accredited Capacity (MW)	Annual Energy (Gwh)	In-Service Date	Retirement Date
ShortTrm	644	644	1.421952	2008	2100
Barron	0.265	0	0.1314	2000	2100
FlyngCld	4.6	4.6	0.4010002	2000	2019
HERC	33.7	33.7	221.412	2000	2017
MNMethan	3.1	3.1	20.63799	2000	2014
PineBend	12	12	68.327	2000	2026
RARH	12	0	29.86556	2008	2028
***HYDRO**					
Byllesby	2.36	2.596	14.469	2000	2100
CrownHyd	0	0	0	2100	2027
EauGalle	0.3	0.3	1.448001	2000	2026
FordMoCo	18	18	100.724	2000	2009
Hastings	3.3	3.3	20.23559	2000	2033
LacCourt	3.1	3.1	8.146792	2000	2021
Neshonoc	0.4	0.4	2.452799	2000	2020
Rapidan	2.8	2.8	17.16699	2000	2017
SAF Hydr	0	0	0	2100	2022
St.Cloud	7.9	6.6992	44.18498	2000	2021
***MANITOBA**					
MH500	500	500	2091.428	2000	5015
Div150In	150	150	132.48	2000	2015
Div200In	200	200	176.64	2000	2015
Dv150out	150	0	0.651599	2000	2015
Dv200out	200	0	0.8688014	2000	2015
***WIND**					
SmalWind	184.06	21.70067	554.7561	2000	2099
WoodStck	10.2	1.31784	32.93192	2000	2034
Lakota	11.25	1.4535	36.32197	2000	2034
Shaokata	11.88	1.534896	38.356	2000	2034
Velva	11.88	1.481436	37.34566	2000	2026
NorthWnd	14	0	10.21559	2008	2028
NorthCom	16	0	11.67496	2008	2028
Kenyon	18.9	0	14.71679	2008	2028
Ewington	19.95	2.35011	60.10678	2007	2027
GrantCo	0	0	0	2009	2028
Herman	0	0	0	2009	2028
WestStev	0	0	0	2009	2028
WindPowr	25	3.23	80.71548	2000	2018

Jeffers	50	5.89	150.6436	2007	2027
Moraine	51	6.5892	164.6596	2003	2018
Chanaram	85.5	11.0466	276.047	2003	2023
FPL Mowr	98.9	10.71087	279.9105	2006	2026
LkBnton1	107.25	13.8567	346.2695	2000	2023
LkBnton2	103.5	13.3722	334.1622	2000	2030
MNDakota	150	20.46	504.6496	2007	2022
Fenton	200	25.84	645.7239	2007	2032
GrandMed	100	13.6	334.9539	2009	2033
CBED1	100	11.8	300.5987	2008	2033
CBED2	200	23.6	601.1974	2010	2035

Hydro Units

	Annual Energy (Gwh)	Accredited Capacity (MW)
AppleRiv 1	11.555	3
BigFalls 1	26.313	8
CedarFls 1	26.60249	7
Chippewa 1	44.609	24
Cornell 1	57.217	33
EauClare 1	30.067	8
Hayward 1	1.405857	1
HennIsld 1	57.151	11
Holcombe 1	64.369	36
JimFalls 1	80.58202	57
Ladysmth 1	8.097047	3
Menomoni 1	19.102	6
Riverdal 1	2.251	2
SaxonFls 1	9.877274	2
St.Croix 1	98.021	24
Superior 1	10.906	2
Thornapl 1	7.057001	2
Trego 1	6.083	2
WhiteRiv 1	3.995	2
Wissota 1	92.15601	36

Generic Wind

Maximum Capacity (MW)[1]	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
O Wind12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100
O Wind13	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100
O Wind 6	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100
O Wind 8	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100
O Wind 3	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100
O Wind14	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100
O Wind 5	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100
O Wind14	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100
O Wind12	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100
O Wind13	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100
O Wind11	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100
O Wind14	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100
O Wind13	0	0	0	0	0	0	0	100	100	100	100	100	100	100	100
O Wind 5	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100
O Wind 2	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100
O Wind12	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100
O Wind 8	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100
O Wind 5	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100
O Wind 4	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100
O Wind14	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
O Wind 3	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100
O Wind13	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100
O Wind 3	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100
O Wind13	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Total Generic Wind	**0**	**100**	**300**	**500**	**700**	**900**	**1100**	**1300**	**1500**	**1700**	**1900**	**2100**	**2300**	**2300**	**2400**

1 The Capacity Factor for wind is 12.5%

Fuel

Spot & Delivery	2008	2009	2010	2011	2012	2013	2014	2015
Coal[1]	1.825	1.894	1.926	2.069	2.052	2.059	2.059	2.070
Nuke	0.519	0.517	0.726	0.776	0.990	1.037	1.119	1.139
Bio	1.219	1.242	1.267	1.293	1.319	1.347	1.375	1.404
RDF	0.194	0.198	0.202	0.206	0.210	0.215	0.219	0.224
NatGas[2]	8.384	8.785	8.655	8.426	8.214	6.990	7.083	7.452
Oil	16.240	15.677	14.846	14.071	13.466	11.757	11.885	12.453

Spot & Delivery	2016	2017	2018	2019	2020	2021	2022
Coal[1]	2.104	2.148	2.182	2.227	2.272	2.307	2.353
Nuke	1.131	1.128	1.093	1.083	1.092	1.089	1.112
Bio	1.431	1.457	1.485	1.513	1.541	1.570	1.600
RDF	0.228	0.233	0.237	0.241	0.246	0.251	0.255
NatGas[2]	7.728	7.834	7.745	8.001	8.327	8.558	8.879
Oil	13.015	13.400	13.383	13.882	14.495	14.903	15.455

1 This price is representative of the WY and MT coal that we burn at our coal fired plants. The price is a combination of spot and rail/delivery costs.

2 Natural gas prices through 2012 are taken directly from the reference day's (in this case October 26, 2007) closing prices for the NYMEX Natural Gas forward contracts. Pricing from 2013 - 2022 is developed by taking the simple average of the forward estimates from various third party and govenmental entities. Gas prices in all years includes an demand cost adder.

Financial

Composite Tax Rate (%)	41.37
Customer Discount Rate (%)	8.18
Debt Service Reserve Percent (%)	0
Federal Income Tax Rate (%)	35
Inflation Rate (%)	1.99
Real Discount Rate (%)	5.44
Reserve and Contingency Reserve (%)	0
Utility Discount Rate (%)	7.42

Weighted Cost of Capital (%)	7.42		
AFUDC Offset Percent (%)	0		
AFUDC Rate (%)	8.36		
Capitalized Interest Debt Rate (%)	7.08		
Debt Portion of AFUDC (%)	0		
Debt Structure for Book (%)	48.33		
Debt Structure for Tax (%)	48.33		
Desired Return on Rate Base (%)	7.42		
Insurance Rate (%)	0.04		
ITC Rate (%)	0		
Long Term Debt Interest Rate (%)	7.08		
Nuclear Waste Disposal Rate ($/MWH)	$0.00		
Other Tax Rate (%)	0		
Property Tax Rate (%)	1.67		
Revenue Tax Factor (%)	0		
			%
ESCALATION RATE SCHEDULE	Labor		3.34
	NonLabor		1.17
	Capital		1.88
	Weighted		1.99
	L25C75		1.71
	L50C50		2.26
	L75C25		2.8
	4 Prct		4
	3 Prct		3
	2 Prct		2
	5 Prct		5
	6 Prct		6
	7 Prct		7
	1Prct		1
	L40C60		1.99

As can be seen, the differences between the OES 1.1 percent energy savings scenario expansion plan and the 1.3 percent OES energy savings scenario expansion plan are minimal through 2021. The main difference is the delay in the procurement of two combined cycle power plants by one year (one plant delayed from 2015 to 2016 and another plant delayed from 2018 to 2019).

The differences between the OES 1.1 percent energy savings scenario expansion plan and the 1.5 percent OES energy savings scenario expansion plan are more significant up through 2021. The OES 1.5 percent expansion plan would result in the delay of a peaking plant from 2012 to 2020 and the elimination of an intermediate plant in 2018.

The OES conducted this exercise to determine whether requiring Xcel to adopt higher energy savings goals than proposed could result in reliability problems in the event that Xcel does not meet higher energy and demand savings goals. The expansion plan resulting from implementation of the 1.3 percent energy savings scenario does not result in a major change in the next ten years. Further, updated modeling and costs of supply-side and demand-side alternatives will be available before a final decision needs to be made as to whether to delay the procurement of an intermediate plant. However, the expansion plan resulting from implementation of the 1.5 percent scenario results in the seven-year deferral of the procurement of a peaking scheduled to be online in 2012. Updated analysis for Xcel's next resource plan will not be available in time to change the procurement of that 2012 resource. If the Commission approved the 1.5 percent energy savings scenario and Xcel were not able to obtain the energy and demand savings assumed, Xcel would have to procure expensive peaking capacity from the market.

Both Xcel and OES's modeling of energy savings scenarios assume that energy-savings goals are met in 2010. A more realistic scenario would include Xcel ramping up to the energy-savings goals. While meeting the 1.3 percent energy savings scenario in 2010 will be difficult, meeting the 1.5 percent Energy Savings scenario (especially if it includes changes to the energy code, EUIC investments, and appliance standard changes) will be even more difficult. For this reason, the OES recommends that the Commission approve the energy- and demand-savings goals constituted by the 1.3 percent energy savings scenario.

D. OES REVIEW OF XCEL'S MODELING AND ADDITIONAL OES MODELING

1. Introduction

The OES used Strategist to review Xcel's modeling efforts. The general process followed by the OES when reviewing Strategist modeling is as follows:

1. obtain from the applicant a base case file, a preferred case file, and the commands necessary to re-create the various scenarios explored by the Company;
2. re-run the applicant's base case file and preferred case file to make sure the outputs match and that the OES is working with the correct file;
3. review the base case's inputs and outputs for reasonableness;
4. create a new base case which includes any changes deemed necessary to the applicant's base case;

5. run scenarios of interest on the new base case to explore various risks and alternative futures;
6. assess the results of the scenarios and establish a new preferred case; and
7. run scenarios of interest on the new preferred case to test the robustness of the preferred case.

Below the OES explains the results of the analysis process as applied to Xcel's resource plan modeling.

2. Establishing a Base Case

The OES obtained from Xcel the Company's base case,[9] preferred case,[10] and the commands necessary to re-create the various scenarios[11] explored by the Company. In addition, the OES obtained from Xcel the commands necessary to use the Company's 50th percentile forecast in Strategist;[12] see the forecasting section of these comments for further discussion of the 50th and 90th percentile forecasts. Finally, the OES obtained from Xcel the commands necessary to use the Company's Maximum Dependable Capacity (MDC) ratings.[13]

The OES ran Xcel's base case and preferred case and found that the total costs from the OES's modeling results did not match the Company's results. The OES tracked the issue to a difference in the mercury (Hg) emissions for the AS King and Sherco plants in the various files used by Xcel to create the Petition and those sent to the OES in response to Information Requests. The OES asked Xcel about this discrepancy and the Company explained that the issue is a result of how Strategist translated the mercury (Hg) emissions between the various files used by Xcel in the Petition and those sent by Xcel to the OES. In essence, the Hg emissions are so small that, in translating the files, Strategist improperly rounded certain entries to zero. The OES obtained from Xcel the data necessary to address this issue. The OES then re-ran Xcel's base case and preferred case with the fix provided by the Company and determined that the results matched.

Having established that the OES was working with the correct file, the OES reviewed the inputs and outputs of Xcel's base case and Xcel's preferred case. The OES's review revealed the following issues.

First, the OES noted that the general inflation rate, real discount rate, and nominal discount rate could not be calculated from each other using a standard formula. However, considering the large number of inflation rates used by the Company and the small size of the differences, the OES did not pursue this issue further.

Second, the OES noted that Xcel's base case did not include the Commission's externality costs. Rather, the Company tested those values as a contingency scenario. While this is not necessarily incorrect under Commission Orders, the OES prefers that the base case include some level of

[9] See Xcel's response to OES Information Request No. 1.
[10] See Xcel's response to OES Information Request No. 3.
[11] See Xcel's response to OES Information Request Nos. 2, 8, and 9.
[12] See Xcel's response to OES Information Request No. 11.
[13] See Xcel's response to OES Information Request No. 12.

externality values so that the external costs (for example, costs for PM_{10} emissions) are treated similarly to the internal costs (such as the cost of SO_2 allowances). Therefore, the OES used the Commission's high externality values as the standard in all analysis and ran the low externality values as a contingency scenario.

Third, Xcel used \$20 per ton as the standard cost for CO_2 emissions; \$20 per ton is not unreasonable. However, the OES used the mid-point of the Commission's \$4 per ton to \$30 per ton as the standard cost for CO_2 emissions, or \$17 per ton. Given the limits of any single number, a sensitivity analysis should be done. Therefore, for each contingency included scenarios using the Commission's \$4 and \$30 values. Note that all CO_2 values were inflated into the future using a 2.5 percent inflator.

Fourth, the OES noted that Xcel omitted certain information regarding the emissions of mercury (Hg) at the Black Dog facility. The OES discussed this omission with Xcel and determined that the omission should be corrected. Therefore, the OES included the missing information regarding Hg emissions.

Fifth, the OES noted that Xcel omitted certain information regarding effluents with an internalized cost (CO_2, SO_2, NO_x, and Hg). The OES discussed this omission with Xcel and determined that the omission should be corrected. Therefore, the OES included the missing information regarding CO_2, SO_2, NO_x, and Hg costs.

Sixth, the OES noted that Xcel included a zero cost for emergency energy in the last few years of the resource plan.[14] The OES corrected this omission by extending the Company's cost of emergency energy for the last few years of the planning period.

The OES did not test these changes separately. However, the OES expects that these six issues, when combined with the issues created in translating files for use by the OES, would have minimal impact on the least cost plan selected by Strategist.

The OES made two further changes which should have a significant impact on the least-cost plan selected by Strategist. First, the OES used Xcel's median (50th percentile) forecast. This change reduces the Company's demand forecast but does not change the Company's energy forecast. Thus, the OES's forecast change creates a system with a higher load factor than under Xcel's forecast. The OES's preferred forecast method is discussed elsewhere in these comments and in the May 14, 2004 *Direct Testimony of Hwikwon Ham* in Docket No. E002/CN-04-76.

Second, the OES used the maximum dependable capacity (MDC) ratings for all generators. The MDC ratings are more representative of what these units can be relied upon to produce at peak times than the URGE (Uniform Rating of Generating Equipment) approach. For further discussion see the May 14, 2004 *Direct Testimony of Steve Rakow* in Docket No. E002/CN-04-76.

[14] The Company did not enter a value and, therefore, Strategist would treat the cost as zero.

The last two changes appear to be consistent with the likely direction of changes regarding forecast and unit ratings being developed for reliability purposes by the Mid-continent Area Power Pool's Planning Reserve Sharing Group (MAPP PRSG) and the Midwest Reliability Organization (MRO). See pages 4-19 and 4-20 of the Petition.

The OES notes that Xcel used a 40-year planning period (2008 through 2047), rather than the standard 15-year planning period.[15] Xcel also used an infinite end-effects period. The resulting study period (the planning period plus the end effects period equals the study period) is the longest possible when using Strategist. Considering that the instant resource plan must evaluate the question of whether to shut down or pursue a 20-year life extension of the Prairie Island nuclear generating facility, the OES concludes that Xcel's study period is reasonable.

3. New Base Case

The OES ran Xcel's reference case with the changes outlined above. As discussed in Xcel's *Petition*, the expansion units available in Xcel's model are:

1. peaking—represented by a 160 MW natural gas-fired combustion turbine (CT) unit;
2. intermediate—represented by a 600 MW natural gas-fired combined cycle (CC) unit; and
3. baseload—represented by 500 MW coal-fired with carbon sequestration (CWSQ) unit.[16]

The resulting expansion plan is shown in Table 8 and as a comparison to the Company's Base Case.[17]

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[15] The planning period is the duration for which Strategist selects a least-cost expansion plan.

[16] Wind units were not treated as an option by the Company. Instead the Company assumed compliance with the REO/RES of Minn. Stat. §216B.1691. This is a reasonable approach and was also followed by the OES in establishing a base case. Note that the OES did experiment with optional wind units but, due to technical concerns regarding limits to the number of options that can be made available to Strategist, the tests determined that it was not feasible to use optional wind units over the full, 40-year planning period. However, the OES's scenario analysis tested the cost-effectiveness of the REO/RES in a different manner; see below for further details.

[17] Note that the information for Xcel's Base Case expansion plan (to which the OES's base case is compared in Table A) was taken from the Strategist files provided in response to OES Information Request No. 1. According to the files provided by Xcel no peaking unit is added in 2011, which is different from the information provided in Table 4.1 of the Petition.

Table 8: OES Base Case Expansion Plan and Comparison to Xcel Base Case (Number of Units)

Year	OES Preferred Case				Difference from Xcel			
	Wind 100 MW	Peaking 160 MW	Intermediate 600 MW	Baseload 500 MW	Wind 100 MW	Peaking 160 MW	Intermediate 600 MW	Baseload 500 MW
2008	-	-	-	-	-	-	-	-
2009	1	-	-	-	-	-	-	-
2010	2	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-
2012	2	2	-	-	-	(2)	-	-
2013	2	-	1	-	-	(1)	1	-
2014	2	-	-	-	-	-	(1)	-
2015	2	-	1	-	-	-	-	-
2016	2	-	1	-	-	-	1	-
2017	2	-	1	-	-	-	1	-
2018	2	-	-	-	-	-	(1)	-
2019	2	-	-	-	-	-	1	-
2020	2	-	-	-	-	-	-	-
2021	-	-	1	-	-	-	-	-
2022	1	-	-	-	-	-	(1)	-
Total	24	2	5	-	-	(3)	1	-

Table 8 demonstrates that the OES's base case, as compared to Xcel's, eliminates three peaking units in 2012-2013, accelerates the addition of three intermediate units by one year, and adds one intermediate plant.

4. Scenario Analysis

Upon completion of a new base case, the OES proceeded to analyze the impact of various alternatives upon the new base case. The OES analyzed the following scenarios:

1. reduced wind:
   i. no additional wind;
   ii. average 50 MW of wind added annually (add 1 unit at 100 MW every other year);
   iii. average 100 MW of wind added annually (add 1 unit at 100 MW each year);
   iv. average 150 MW of wind added annually (add 3 units at 100 MW during each 2 year period);[18]

[18] Note that if the OES had determined that Xcel's proposed level of wind had a lower cost than scenarios with less wind in most circumstances, then the OES would have experimented with additional wind in order to determine the least-cost level of wind.

2. reduced short-term purchases:
    i. no short-term purchases allowed after 2011;
    ii. allow 500 MW of short-term purchases annually after 2012;
3. the following scenarios:
    i. Black Dog MERP;
    ii. Energy Savings at 1.3 percent;
    iii. extend life of Xcel CTs;
    iv. renew Manitoba Hydro contract;
    v. Monticello EPU;
    vi. Prairie Island EPU;
    vii. Prairie Island shut down; and
    viii. Sherco upgrades.
4. additional miscellaneous scenarios of interest to the OES:
    i. 14.2 percent required reserve ratio; and
    ii. DSM at 1.5 percent.

Thus there are a total of 16 different scenarios. For each scenario the OES ran 13 different contingencies:

1. vary natural gas prices ± 20 percent;
2. vary coal prices ± 20 percent;
3. vary nuclear fuel prices ± 20 percent;
4. escalate capital costs 3 and 5 percent;
5. price CO_2 at $4 and $30 per ton;
6. higher energy sales;
7. lower energy sales; and
8. low externalities.

Regarding the Sherco Upgrades scenario, two additional contingencies were run. First, the OES ran a contingency where Sherco was not upgraded and units were shut down on the following schedule:

- unit 1, retire in 2025;
- unit 2, retire in 2033; and
- unit 3, retire in 2041.

Then the OES ran a contingency where Sherco was upgraded and the units were shut down on the same schedule. The purpose of this analysis was to determine if the upgrades were still cost effective if the units had to shut down in reaction to caps on greenhouse gases, green house gas pricing, or some other event.

Attachment 4 contains selected data from the fuel inputs for the scenarios. Attachment 5 provides selected summary data from the outputs for the 16 scenarios and the new base case. The OES reviewed the information in Attachments A and B in moving to the next stage of the analysis.

5. Revised Scenario Analysis

Based upon the information obtained from the first round of analysis, the OES decided to establish a revised base case and perform further scenario analysis on limited issues using the revised base case. The following scenarios were determined to be preferred and included in the revised base case:

- Black Dog MERP;
- Extend Life of Xcel combustion turbines (CTs);
- Renew Manitoba Hydro contract;
- Monticello EPU;
- Prairie Island EPU;
- Sherco Upgrades; and
- Allow 500 MW of short term purchases annually after 2012.[19]

The above changes were added to the changes in the original OES base case to establish the revised base case. The resulting expansion plan is shown in Table 9 as a comparison to the Company's Base Case.[20]

[19]The OES made this change to reduce Xcel's dependency upon the wholesale market. Although this change will mean that Xcel will have to procure more resources than if higher amounts of short-term purchases were allowed, the change will increase Xcel's reliability and reduce the risk of not being able to obtain economic short-term power.
[20] Note that the information for Xcel's Base Case expansion plan (to which the OES's base case is compared in Table B) was taken from the Strategist files provided in response to OES Information Request No. 1. According to the files provided by Xcel no peaking unit is added in 2011, which is different from the information provided in Table 4.1 of the Petition.

Table 9: OES Revised Base Case Expansion Plan and Comparison to Xcel Base Case (Number of Units)

Year	OES Preferred Case				Difference from Xcel			
	Wind 100 MW	Peaking 160 MW	Intermediate 600 MW	Baseload 500 MW	Wind 100 MW	Peaking 160 MW	Intermediate 600 MW	Baseload 500 MW
2008	-	-	-	-	-	-	-	-
2009	1	-	-	-	-	-	-	-
2010	2	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-
2012	2	2	-	-	-	-	-	-
2013	2	-	-	-	-	-	-	-
2014	2	-	-	-	-	-	-	-
2015	2	-	-	-	-	-	(1)	-
2016	2	-	1	-	-	-	1	-
2017	2	-	-	-	-	-	-	-
2018	2	-	-	-	-	-	(1)	-
2019	2	-	1	-	-	-	1	-
2020	2	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-
2022	1	-	-	-	-	-	(1)	-
Total	24	2	2	-	-	-	(1)	-

These results indicate that the OES's preferred case under the scenario noted above would delay two intermediate units by one year each, and eliminate an intermediate unit in 2022. The OES then ran the revised base case and following scenarios, limited to obtaining further information regarding the economic impact of wind and DSM on Xcel's system:

1. reduced wind:
   i. no additional wind;
   ii. average 50 MW of wind added annually (add 1 unit at 100 MW every other year);
   iii. average 100 MW of wind added annually (add 1 unit at 100 MW each year);
   iv. average 150 MW of wind added annually (add 3 units at 100 MW during each 2 year period); and
   v. delayed addition of early wind units (remove 1 unit per year 2010-2013, add one more unit per year 2015, 2016, 2019, 2020).[21]
2. Increased DSM:
   v. Energy savings at 1.3 percent; and
   vi. Energy savings at 1.5 percent.

[21] The purpose of this scenario was to maintain compliance with the renewable energy objectives of Minnesota Statute §216B.1691, removing some of the over compliance in the early years to reduce compliance costs, yet still maintain an achievable schedule of wind additions.

Thus, the second round of analysis looked at eight scenarios limited to two general issues. When initial tests on some of the above scenarios were run, the Strategist model reported that the scenario failed in 2009 (the model was unable to meet all of the constraints). The OES determined that scenarios were failing due to having reserve margins greater than the maximum allowed as specified by Xcel. To solve this issue, the OES decreased the capacity of the unit representing short term purchases to 500 MW for the years 2008 to 2012.[22] With this fix, Strategist was able to successfully run the scenarios.

The OES notes that, as explained in greater detail in the DSM section of these comments, Xcel modeled its energy savings scenarios using an infinite life for the measures. The OES's initial round of modeling followed a similar approach. However, at this stage the OES modeled the energy savings scenarios with a finite, average 14-year lifetime assumption rather than an infinite life assumption.

Finally, the OES notes that an additional contingency was added during this round of analysis. The OES re-ran the wind scenarios but instead used current market prices for CO_2 allowances in the European Union. The forward prices are available for 2008 to 2014. The current prices are equal to about \$40 for 2008, rising to about \$48 by 2014. The OES used the current prices for 2008 to 2014 and then inflated the 2014 price by 2.5 percent annually to arrive at values for years further into the future.

Attachment 6 provides selected summary data from the outputs for the eight scenarios and the revised base case. Attachment 7 provides the language from Minn. Stat. §216B.1691, subd. 2b, which provides the criteria for the Commission to consider when delaying the RES, as all scenarios except the revised base case do. The OES reviewed the information in Attachments C and D in determining the quantity of DSM and wind energy to include in the preferred case.

6. *Preferred Case*

Based upon the information obtained from the second round of analysis, the OES established a preferred case and performed scenario analysis using the preferred case. The following scenarios were included in the preferred case under the assumption noted above:

- base case wind,[23] and
- 1.3 percent DSM.

The above changes were added to the changes in the OES's revised base case to establish the preferred case. The resulting expansion plan is shown in Table 10 as a comparison to the Company's Preferred Case.

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[22] Note that the capacity of the short term purchases unit was already reduced to 500 MW for the period 2013-2047 as discussed above.
[23] The base case adds 200 MW of wind annually for most of the 15 years of the resource plan time horizon. This strategy maintains compliance with the renewable energy objectives of Minn. Stat. §216B.1691.

Table 10: OES Preferred Case Expansion Plan and Comparison to Xcel's Preferred Case (Number of Units)

	OES Preferred Case				Difference from Xcel			
Year	Wind 100 MW	Peaking 160 MW	Intermediate 600 MW	Baseload 500 MW	Wind 100 MW	Peaking 160 MW	Intermediate 600 MW	Baseload 500 MW
2008	-	-	-	-	-	-	-	-
2009	1	-	-	-	-	-	-	-
2010	2	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-
2012	2	2	-	-	-	-	-	-
2013	2	-	-	-	-	-	-	-
2014	2	-	-	-	-	-	-	-
2015	2	-	-	-	-	-	(1)	-
2016	2	-	1	-	-	-	1	-
2017	2	-	-	-	-	-	-	-
2018	2	-	-	-	-	-	(1)	-
2019	2	-	1	-	-	-	1	-
2020	2	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-
2022	1	-	-	-	-	-	(1)	-
Total	24	2	2	-	-	-	(1)	-

These results, like the results of the previous analysis, would delay intermediate units by one year (from 2015 to 1026 and from 2018 to 2019), and eliminate an intermediate plant in 2022.

The OES selected the 1.3 percent energy savings scenario for the reasons discussed in the DSM section of these comments. The OES selected the base case level of wind for two reasons. First, the estimates of CO_2 prices are particularly uncertain because there is no historical data; in fact CO_2 prices do not even exist at this time. Also, the higher that CO_2 prices go, the better the base case level of wind (about 200 MW annually) performs relative to a scenario with 100 MW of wind added annually. At current European CO_2 market prices, compliance with the RES is the least-cost scenario. Second, the OES was unable to determine that implementation of the RES would cause significant rate impact per Minn. Stat. §216B.1691, subd. 2b. To analyze this requirement, the OES created an estimate of the annual rate impact by calculating the difference, on a real dollar basis, in the annual total cost between the revised base case (200 MW of wind) and the scenario changing the revised base case by adding no more than 100 MW of wind for each year of the 40-year analysis period. The OES acknowledges that this analysis overly simplifies how costs are turned into rates. However, the OES concluded that this level of analysis is sufficient for the purposes at hand.

The annual difference during the 40-year analysis period of procuring Xcel's proposed amount and timing of wind compared to constrained wind, in real dollars, varied between negative \$0.00060 per kWh (i.e., a benefit or cost decrease) and \$0.00132 per kWh (i.e., a cost increase). The average annual real cost increase of implementing Xcel's proposed amount of wind compared to optimized wind amounts during the 40-year analysis period equaled \$0.00046 per kWh or \$4.57 annually for a typical residential customer assuming use of 10,000 kWh per year.[24]

[24] The estimated annual costs for other customer classes could be derived by multiplying the average annual real cost per kWh by the appropriate annual kWh amount.

During the first five years of the plan (2008-2012), the average annual real cost increase equaled \$0.00005 per kWh or \$0.51 annually for a typical residential customer assuming use of 10,000 kWh per year. This analysis indicates that initially the impact of implementing the RES is small, but the cumulative impact builds during the 40-year Strategist analysis period. A case could be made that the cumulative impact is significant, particularly for large customers. However, new resource plans will be filed and the Commission will be able to modify or delay implementation of the RES if the cumulative impact reaches the threshold of significant rate impact as determined by the Commission. However, given the enormous changes in the costs of all supply-side resource materials and fuels, it is difficult to predict at this time whether implementing the RES would cost more in the long term as compared to a plan that included less wind and other renewables. However, this issue clearly needs to be monitored.

7. *Testing the Preferred Case*

For the preferred case OES ran 15 different contingencies:

1. vary natural gas prices ± 20 percent;
2. vary coal prices ± 20 percent;
3. vary nuclear fuel prices ± 20 percent;
4. escalate capital costs 3 and 5 percent;
5. price CO_2 at \$4, \$30, and European allowance cost per ton;
6. 14.2 percent required reserve ratio (to recognize Xcel's withdrawal from MAPP);
7. higher energy sales;
8. lower energy sales; and
9. low externalities.

The OES's preferred case was the least-cost expansion plan for the following 11 scenarios:

- \$4/ton CO_2;
- \$30/ton CO_2;
- European Union CO_2 prices;
- vary coal prices plus 20 percent;
- vary coal prices minus 20 percent;
- escalate capital costs 3 percent;
- low externalities;
- vary natural gas prices plus 20 percent;
- vary natural gas prices minus 20 percent;

- vary nuclear fuel prices plus 20 percent; and
- vary nuclear fuel prices minus 20 percent.

For the four remaining alternative scenarios in which the OES preferred plan was not cost-effective, changes to the least-cost plan can be summarized as follows:

- 14.2 percent required reserve ratio:
    - defer 1 CT (2012) 3 years;
    - add 1 CT (2019); and
    - defer 1 CC (2019) 3 years;
- low load:
    - add 1 CT (2019); and
    - defer 1 CC (2019) 3 years;
- high load:
    - accelerate 1 CC (2016) 1 year;
- escalate capital costs 5 percent:
    - eliminate 1 CC (2019); and
    - add 3 CTs (2019, 2020, 2022).

Based upon this information OES concludes that our preferred expansion plan is robust in that it does not change under any variation in the price of coal, natural gas, nuclear fuel, or carbon pricing. It also does not change for modest increases in capital costs. Table 11 below shows the OES Preferred Plan, including planned additions other than the generic units modeled by Xcel and the OES and DSM.

Table 11: OES Preferred Xcel Expansion Plan

	Planned Additions	Intermediate	Peaking	Wind	DSM
2008		High Bridge CC 624 MW			91 MW
2009	Rahr 12 MW	Riverside CC 508 MW		100 MW CBED 209 MW Grand Meadows 100 MW	93 MW
2010				200 MW	132 MW
2011	Monticello 68 MW			200 MW CBED 200 MW	138 MW
2012	Sherco 2 30 MW Sherco 3 10 MW		320 MW	200 MW	138 MW
2013	Sherco 1 44 MW PI 83 MW	Black Dog 300 MW		200 MW	139 MW
2014				200 MW	133 MW
2015	Manitoba Hydro 375MW Manitoba Hydro DIV 350 PI 2 87 MW			200 MW	121 MW
2016		600 MW		200 MW	132 MW
2017				200 MW	134 MW
2018				200 MW	138 MW
2019		600 MW		200 MW	141 MW
2020				200 MW	157 MW
2021	Manitoba Hydro 125 MW				159 MW
2022				100 MW	161 MW

8. *Summary of Modeling Review*

OES recommends that the Commission approve OES' Preferred Plan, as provided in Table 11 above. Further, given the importance of the OES's ability to review Xcel's modeling, cooperate with Xcel's modelers in addressing issues discovered in our review, and conducting our own capacity expansion modeling, the OES recommends that the Commission strongly encourage Xcel to use Strategist in the Company's next resource plan.

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE MONTICELLO NUCLEAR GENERATING PLANT EXTENDED POWER UPRATE	Docket No. E002/CN-08-185

DIRECT TESTIMONY AND EXHIBITS OF DR. STEVE RAKOW

ON BEHALF

OF THE MINNESOTA OFFICE OF ENERGY SECURITY

September 3, 2008

DIRECT TESTIMONY OF DR. STEVE RAKOW
IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE MONTICELLO NUCLEAR GENERATING PLANT EXTENDED POWER UPRATE

DOCKET NO.E002/CN-08-185

TABLE OF CONTENTS

I. INTRODUCTION

Q. What is your name, business address, and occupation?

A. My name is Dr. Steve Rakow. My business address is 85 Seventh Place East, Suite 500, St. Paul, Minnesota 55101-2198. I am employed as a Public Utilities Rates Analyst with the Minnesota Office of Energy Security (OES).

Q. What is your educational and professional background?

A. A summary of these items is included as OES Exhibit No. ___ (SRR-1). In addition, I note that all information requests and responses referred to in this text are available in OES Exhibit No. ___ (SRR-2).

Q. What are your responsibilities in this proceeding?

A. I am submitting testimony on behalf of the OES that:

- summarizes Northern States Power Company, a Minnesota Corporation's (NSP, Xcel or the Company) *Petition to the Minnesota Public Utilities Commission for Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate* (Petition);
- presents the criteria established by Minnesota Statutes and Minnesota Rules that the Minnesota Public Utilities Commission (Commission) will use to decide whether to approve the Petition;
- introduces the other witnesses sponsored by the OES in this proceeding;
- provides the OES's analysis of alternatives and policy; and
- summarizes the OES's overall conclusions and recommendations at this time.

II. SUMMARY OF CERTIFICATE OF NEED

A. THE APPLICANT'S CASE

Q. Who is the applicant for the certificate of need in this proceeding?

A. Xcel requests a certificate of need (CN) for a modified generating facility. Thus, Xcel is the Applicant for the CN.

Q. Please summarize Xcel's Petition.

A. As described in the Petition, Xcel requests a CN for a 71 MW increase in the generating capability of the Monticello Nuclear Generating Plant (MNGP). The increase is proposed to occur in two steps, a 15 MW increase during the 2009 refueling outage and a 56 MW increase during the 2011 refueling outage.

The Petition indicates that the increase would result in a total of approximately 230 additional fuel assemblies being used over the remaining operating life of the facility. As a result three additional storage containers may be necessary to support operation of MNGP through 2030. However, the additional storage containers do not become needed until about 2025. The Petition states that no additional storage containers are requested at this time because the federal government may begin removing spent fuel prior to 2025.[1]

The project is estimated to cost $104 million to $133 million, depending upon whether or not a new steam dryer is needed. Thus, the installed cost is expected to be between $1,465 per kW and $1,873 per kW. Finally, the footprint of the existing site will not be expanded due to the uprate project.[2]

[1] See page 3-19 of the Petition.
[2] See page 3-20 of the Petition.

Regarding the alternatives, the Petition states at pages 1-12 and 1-13 that facilities providing an equivalent amount of capacity but burning natural gas, coal, or biomass would result in an incremental cost of between $169 million and $514 million on a present value of the revenue requirements (PVRR) basis and result in CO_2 emissions of between 6.4 and 25.1 million tons, whereas the project would produce no CO_2 emissions.

Q. Is a CN required for the proposed facility?

A. Yes, for the following reasons. First, Minnesota Statutes §216B.2421, subd. 2 (1) defines a large energy facility (LEF) as "any electric power generating plant or combination of plants at a single site with a combined capacity of 50,000 kilowatts or more..." The proposed changes to the generating facility have a capacity of above 50 MW and thus qualify as a LEF.

Second, Minnesota Statutes §216B.243, subd. 2 states that "no large energy facility shall be sited or constructed in Minnesota without the issuance of a certificate of need by the Commission…" Therefore, a CN is required to be approved by the Commission before the proposed LEF could be sited or constructed.

Q. When must the Commission make a decision regarding the Petition?

A. Minnesota Statutes §216B.243, subd. 5 states "Within 12 months of the submission of an application, the Commission shall approve or deny a certificate of need for the facility." Therefore, under the CN process the due date for a Commission decision regarding the Petition is 12 months from the date of the Applicant's submission of all of the required data. On April 7, 2008, the Applicant filed its *Petition to the Minnesota Public Utilities*

Commission for Certificate of Need for the Monticello Nuclear Generating Plant for Extended Power Uprate, Supplemental Filing (Supplement) which provided the data required by Minnesota Rules.

The Commission's April 18, 2008 *Order Accepting Application as Substantially Complete and Notice and Order for Hearing* states that the Commission "finds that the application as supplemented is substantially complete." Thus the due date for a Commission decision is April 7, 2009.

Q. How does the Applicant justify the need for the proposed LEF?

A. On page 1-1 of the Petition Xcel summarizes the Company's claim that the proposed LEF is needed because the proposed LEF:

- is the most cost-effective option to meet growing energy and capacity needs;
- is a non-carbon emitting resource; and
- is a hedge against future exposure to fossil-fuel prices and environmental regulation.

B. THE OES'S CASE

Q. Please introduce the witnesses sponsored by the OES in this proceeding.

A. In addition to myself, the OES is sponsoring three other witnesses in this proceeding:

- Mr. Christopher T. Davis;
- Mr. Hwikwon Ham; and
- Ms. Susan Peirce.

Mr. Davis addresses issues regarding demand-side management (DSM). Mr. Ham addresses issues regarding forecasting. Ms. Pierce addresses issues regarding compliance with the renewable energy objective. I address issues related to alternatives and policy.

Q. Please summarize the criteria to be considered by the Commission during this proceeding and explain generally how the OES addresses the criteria.

A. There are several factors to be considered by the Commission in making a determination in CN proceedings. In a general manner, these factors are located in different sections of Minnesota Statutes. Some of the statutory criteria are reflected in a more specific way in Minnesota Rules part 7849.0120. However, some statutory criteria do not appear to be reflected in rules (for example, the 'innovative energy project' language of §216B.1694, subd. 2). To clarify this situation, a comprehensive list of the criteria and how they are addressed by the OES's witnesses is provided in OES Exhibit No. ___ (SRR-3). I note that in OES Exhibit No. ___ (SRR-3) several of the rule criteria have been moved from their location in the rule; this was done to better focus the testimony of the OES's witnesses on their areas of expertise and enable the OES to present a more coherent overall analysis and recommendation.

III. RENEWABLE ALTERNATIVES TO THE PROPOSED FACILITY

A. OVERVIEW

Q. What are the criteria regarding the renewable alternatives established by Minnesota Statutes that the Commission must consider when determining whether

a more reasonable and prudent renewable alternative to the proposed facility has been demonstrated to the Commission's satisfaction?

A. Minnesota Statutes §216B.243, subd. 3a, states that:

> The Commission may not issue a certificate of need under this section for a large energy facility that generates electric power by means of a nonrenewable energy source, or that transmits electric power generated by means of a nonrenewable energy source, unless the applicant for the certificate has demonstrated to the Commission's satisfaction that it has explored the possibility of generating power by means of renewable energy sources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source.

In addition, Minnesota Statutes §216B.2422, subdivision 4, states that "The Commission shall not approve a new or refurbished nonrenewable energy facility in … a certificate of need, pursuant to section 216B.243, … unless the utility has demonstrated that a renewable energy facility is not in the public interest."

Q. What energy sources are considered renewable?

A. For purposes of Minnesota Statutes §216B.243, subdivision 3a "renewable energy source" includes:

- hydro;
- wind;
- solar;
- geothermal energy; and
- the use of trees or other vegetation as fuel.

B. SCREENING ANALYSIS OF RENEWABLES

Q. What criteria did Xcel use in the Company's screening analysis?

A. On pages 6-1 and 6-2 of the Petition Xcel lists and explains the following screening criteria:

- cost;
- environmental impacts;
- reliability; and
- appropriateness.

If an alternative passes each of the above criteria, a cost analysis of that alternative should be provided. However, if an alternative does not meet all of the above criteria then a cost analysis is unnecessary.

Q. Are Xcel's screening criteria reasonable?

A. Yes, they are reasonable. The criteria used by Xcel in the Petition are similar to the screening criteria used in similar certificate of need dockets in the recent past. For example, see OES Exhibit No. ___ (SRR-4) for a list of the screening criteria I used in the MNGP relicensing proceeding (Docket No. E002/CN-05-123).

Q. Do any of the resources considered as renewable by Minnesota Statutes §216B.243, subdivision 3a pass Xcel's four screening criteria?

A. In general, all the renewables fail one of the screening tests. Briefly:

- hydro—is not available at all, or not available in a timely manner;
- wind—is of the wrong type, as it is not a baseload technology;

- solar—is of the wrong type, as it is not a baseload technology;
- geothermal energy—is not available at all; and
- the use of trees or other vegetation as fuel—is costly and potentially has emission and availability issues.

While it is not necessary to do so since biomass and wind failed the screening tests, below I provide an economic analyses of biomass and wind alternatives.

C. COSTING RENEWABLES

Q. Did Xcel provide a cost analysis of a renewable alternative?

A. Yes, Xcel used the Strategist model to compare the MNGP EPU to a 71 MW biomass plant. Xcel ran a series of scenarios with the MNGP EPU and a series of scenarios with the 71 MW biomass alternative. Specifically, the Company ran a base case and 16 different contingencies for the proposed MNGP EPU and the biomass alternative. The results are summarized in Table 6-7 (page 6-18) of the Petition, which shows that the biomass alternative has a higher cost, between $362 and $790 million dollars PVRR.

Q. Please explain how you performed a cost analysis of renewables.

A. I started with the OES's preferred case from Xcel's most recent resource plan (Docket No. E002/RP-07-1572). Selected pages from the OES's June 16, 2006 comments on Xcel's resource plan, discussing OES's preferred case, are provided OES Exhibit No. ___ (SRR-5). I removed the MNGP EPU from this base case and added the MNGP EPU but with added costs for steam dryer replacement.[3] The information for the MNGP with

[3] Note that steam dryer replacement may or may not be necessary and, therefore, the assumption that a steam dryer is needed increases costs and thus biases the analysis against the Company's proposal.

steam dryer replacement was provided by Xcel in response to OES Information Request No. 1.

Second, I modeled both a biomass option and a 'wind plus system back-up' option as renewable alternatives.[4] Therefore, in OES Information Request No. 1, I obtained the commands necessary to model the biomass alternative. I already had the necessary information for the 'wind plus system back-up' option.

Third, I forced Strategist to add a 71 MW biomass facility to the base case. I then ran the resulting scenario and 13 different contingencies. By subtracting the cost of the biomass alternative case from the base case I determined the incremental cost of the biomass alternative. Fourth, I forced Strategist to add two additional 100 MW wind facilities. I then ran the resulting scenario and 13 different contingencies. By subtracting the cost of the wind plus system back-up alternative case from the base case I determined the incremental cost of the wind plus system back-up alternative.

Q. What were the results of your cost analysis of renewables?

A. The results of my cost analysis are summarized below in Table 1.

[4] I make no judgment on whether a 'wind plus system back-up' option is actually a renewable alternative since, as explained below, it fails an economic comparison.

Table 1: MNGP EPU and the Renewable Alternatives (PVSC $,000)

Scenario	MNGP EPU with Steam Dryer	Biomass Alternative	Wind Alternative
Main Case	$ -	$321,208	$396,440
$4 CO2	$ -	$136,356	$415,416
$30 CO2	$ -	$461,552	$384,216
Coal – 20%	$ -	$320,720	$398,976
Coal + 20%	$ -	$321,688	$393,872
Capacity + 3%	$ -	$320,712	$407,984
Capacity + 5%	$ -	$319,520	$440,152
Low Externalities	$ -	$320,800	$396,568
Gas – 20%	$ -	$319,272	$404,520
Gas + 20%	$ -	$322,888	$400,384
High Load	$ -	$333,376	$351,976
Low Load	$ -	$320,704	$430,792
Nuke – 20%	$ -	$332,016	$407,248
Nuke + 20%	$ -	$308,880	$384,112

Q. Please explain, generally, what these numbers represent.

A. The numbers in the "Biomass Alternative" column show the incremental cost of the biomass alternatives compared to the MNGP EPU with Steam Dryer, under all of the scenarios listed. Positive numbers indicate that the alternative is more expensive than the MNGP EPU with Steam Dryer. Likewise, for the "Wind Alternative" figures in all of the scenarios. I note that the column of MNGP EPU with Steam Dryer shows "$-" since this is the base case against which the alternatives are compared.

Q. Do you conclude that the alternative selected (the MNGP EPU) is less expensive (including environmental costs) than power generated by a renewable energy source?

A. Yes. Using the criteria and conclusions above, the renewable alternatives are either not feasible or are more expensive (including environmental costs) than power generated by the proposed MNGP EPU.

Q. What about the environmental costs of nuclear power?

A. Attached to this testimony are Pages 42 to 51 from my direct testimony in Docket No. E002/CN-05-123, the certificate of need proceeding for an independent spent fuel storage installation at MNGP, regarding a discussion of nuclear externality values [OES Exhibit No. __ (SRR-6)]. Based upon this discussion there are two categories of nuclear externality values to consider. First is the cost of a severe accident at MNGP. The Petition states at page 4-13 that "this change will not increase the probability of operator error or equipment malfunction that would result in an uncontrolled radioactive release." Therefore, I conclude that there is no incremental impact on the cost of a severe accident at MNGP due to the EPU.

The second category of nuclear externality values to consider is the cost related to on-going operations. As shown in OES Exhibit No. __ (SRR-6) there are five potential impact areas for radioactive emissions from on-going operations. The five potential impact areas for radioactive emissions from on-going operations and my conclusion regarding them are as follows:

- off-site exposure cost—based upon the response to OES Information Request No. 5, routine operations will not have a significant incremental impact on off-site exposure cost ($0 is appropriate);

- off-site economic cost—based upon OES Exhibit No. ___ (SRR-6) routine operations will not have a significant incremental impact on the local or regional economy ($0 is appropriate);
- on-site exposure cost—based upon OES Exhibit No. ___ (SRR-6) externality costs due to on-site exposure from routine operations, if any, are likely to be minimal and internal costs are likely covered by health insurance ($0 is appropriate);
- on-site cleanup cost—the costs of decommissioning already include the costs associated with on-site cleanup due to routine operations ($0 is appropriate); and
- replacement power—the costs of replacement power during routine operations is already included within Strategist ($0 is appropriate).

In summary, the nuclear externality value associated with the impact of the MNGP EPU on routine operations is zero or is already included within Strategist.

IV. NON-RENEWABLE ALTERNATIVES TO THE PROPOSED FACILITY

A. OVERVIEW

Q. What are the criteria established by Minnesota Rules that the Commission must consider when determining if a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence?

A. Under Minnesota Rules 7855.0120 B, the Commission must consider the following criteria:

- the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
- the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;
- the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and
- the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives

Q. What alternatives should the Commission consider in making its determination?

A. Minnesota Rules 7849.0110 states "The Commission shall consider only those alternatives proposed before the close of the public hearing and for which there exists substantial evidence on the record with respect to each of the criteria listed in part 7849.0120."

Q. What non-renewable, non-IGCC alternatives do you consider?

A. I considered the following alternatives:

- a coal-fired facility;
- a natural gas-fired combined cycle (CC) facility;
- a combustion turbine (CT) facility;
- transmission; and
- purchased power.

I note that OES Witness Mr. Davis discusses issues related to DSM.

B. SCREENING OF NON-RENEWABLE ALTERNATIVES

1. Size

Q. Please discuss the appropriateness of the size of the proposed facility compared to that of reasonable alternatives.

A. If approved, the EPU would allow MNGP to provide about 71 MW of additional capacity and the associated energy of a unit capable of operating at about a 90 percent capacity factor for Xcel's system beginning with the refueling outage in 2011 (with 15 MW of the capacity and energy available after the 2009 refueling outage).

In a general way, nearly all of the alternatives can meet the proposed project's size requirement since Xcel has facilities of 71 MW or larger of each alternatives. Thus, there is no reason to conclude that such alternatives could not provide 71 MW of capacity and energy. The only question would revolve around purchased power. In general, purchased power contracts can be structured so as to provide various amounts of energy and capacity desired. Therefore, in general purchased power would meet the size criterion. However, the specific sizes in which purchased power can be made available would vary depending upon the conditions prevailing in energy markets at any one time.

Additionally, I should note that transmission facilities by themselves do not provide energy or capacity. In this context a transmission alternative would provide Xcel access to generation sources that otherwise would not be available. Furthermore, all of the alternatives likely involve construction of at least a minor transmission line. Thus, to distinguish the transmission alternative from the other alternatives, the transmission alternative should be thought of as a lengthy transmission line accessing generation otherwise not accessible.

2. Type

Q. Please compare the appropriateness of the type of the proposed facility to that of reasonable alternatives.

A. Xcel is proposing the facility as a means of increasing baseload capacity – generating units that are efficient at providing energy on a year-round basis. Such a unit must be able to operate as many hours a year as possible. Since baseload units are used as much as possible, energy costs should be minimized. Thus, in order to meet the type criterion an alternative would have to be able to operate, both in an economic and engineering sense, in baseload mode.

<u>Coal-fired facilities</u>: Simply put, a coal-fired facility burns coal to heat water and uses the resulting steam to produce electricity. Such a configuration is most economic when in continuous operation for an extended duration. Therefore, a coal-fired alternative meets the type criterion.

<u>Natural-gas-fired (CC)</u>: A CC alternative has, as part of its operation both a CT and a steam turbine. A steam turbine could allow such a facility to operate as a baseload unit. Further, a CC configuration can be highly efficient in terms of the Btus of fuel required to produce a Btu of electricity. However, given the prices of natural gas prevailing today, it is unlikely that a CC alternative would be economical under baseload operations. Therefore, a CC alternative does not meet the type criterion.

<u>CT facility</u>: CTs are typically employed in peaking duty. CTs can be started up and shut down on relatively short notice and have relatively low capital costs. However, the trade-off is that the energy produced by a CT is relatively expensive. Therefore, the CT alternative fails the type criterion.

Transmission facilities: Transmission facilities do not by themselves provide electric energy or capacity. They move electricity from one location to another. A transmission line could be sited such that it moves electricity from a new or currently existing (but not accessible) baseload unit to Xcel's load center. Therefore, a transmission alternative meets the type criterion to the extent that the access extends to a baseload facility that is able to provide economical power. I assume that such access is possible.

Purchased power: Generally speaking purchased power contracts can be tailored to the need at hand. Purchased power contracts can be structured to provide baseload energy or peaking capacity and can be long term or short term. That flexibility is only limited by the availability in the market of sources of the appropriate type. The specific types available in the market at any one time would depend upon market conditions prevailing at that time. Therefore, in general the purchased power alternative meets the type criterion.

3. Timing

Q. Please compare the appropriateness of the timing of the proposed facility to reasonable alternatives.

A. Coal-fired facility: In order to meet the timing criterion an alternative would have to be able to provide significant capacity and energy by 2011. A coal-fired alternative could not meet such a schedule.

Natural-gas-fired CC facility: A CC alternative would not take as long to bring on-line as a coal alternative. For example, the certificate of need application for Xcel's

Black Dog repowering project was filed in late 1999 and I understand that the repowering project was completed by 2002. While a non-repowering project might take somewhat longer to complete, the duration still should be such that a CC alternative would be available when needed. Therefore, the CC alternative meets the timing criterion.

CT facility: A CT alternative could be constructed in a year or less. In addition, the permitting process for a CT alternative would require about a year. Therefore, a CT meets the timing criterion.

Transmission facilities: Depending on the length of the facilities involved and other factors, transmission facilities can be constructed within a relatively short lead time. However, a transmission line of significant length, which is the focus of this alternative, would likely require an extensive construction period and certainly would require a lengthy permitting process. This length of time would occur not only because the transmission line in question would have to be built, but it is possible that significant other transmission infrastructure would also be required. For example, see Xcel's transmission improvements in the Buffalo Ridge region of Minnesota (Docket No. E002/CN-01-1958). Furthermore, if a year is allowed for development, based upon the likely duration of the construction and permitting processes, the transmission alternative fails the timing criterion.

Purchased power: Generally speaking, purchased power contracts can be tailored to the need at hand. That flexibility is only limited by the availability of generation and transmission sources with the appropriate timing. The specific timing of purchased power available at any one time would depend upon market conditions. Therefore, in general the purchased power alternative meets the timing criterion.

4. Summary

Q. Please summarize your screening of the alternatives based upon the appropriateness of the size, type and timing.

A. Table 2 below summarizes the size, type, and timing screening.

Table 2: Summary of Screening Analysis

Alternative	Size	Type	Timing
Coal	Yes	Yes	No
Combined Cycle	Yes	No	Yes
Combustion Turbine	Yes	No	Yes
Transmission	Yes	Yes	No
Purchased Power	Yes	Yes	Yes

Coal, CT, CC and Transmission: Table 2 shows that the CT, CC, and transmission alternatives all fail to meet at least one of the screening criteria. Therefore, they are dropped from further consideration. While the coal facility in isolation fails the timing criterion, I include a coal alternative in the cost analysis to demonstrate the impact of a new 71 MW coal unit.

Purchased Power: Purchased power passes all of the screening criteria. However, a separate cost analysis cannot be provided. To the extent a hypothetical purchased power alternative is based upon a new unit, the feasible alternatives are already analyzed. To the extent a hypothetical purchased power alternative is based upon an existing unit, a cost analysis is not possible without access to data regarding the unit in question. Finally, any developer that wishes to offer a purchased power alternative can participate in this process. Therefore, a separate purchased power unit is not included in my cost analysis below. However, if a developer were to provide a specific purchased power alternative in a timely manner, it may be possible to assess such a proposal in this proceeding.

Q. What about a no-build alternative?

A. The no-build alternative would be covered by the unconstrained alternative, discussed below. If the no-build alternative were feasible and least cost, Strategist would choose to add no additional units and the result would be cheaper than the MNGP EPU with steam dryer replacement scenario.

C. ECONOMIC COST OF ALTERNATIVES

Q. Please explain how you performed a cost analysis of non-renewable alternatives.

A. I followed the same process as for renewable alternatives. I started with the same base case (MNGP EPU with steam dryer replacement). Based upon the screening analysis, I modeled both a coal option and an unconstrained option. The coal option is a 71 MW coal unit which Strategist is forced to accept. Therefore, in OES Information Request No. 1, I obtained the commands necessary to model the coal alternative. The unconstrained option does not have the MNGP EPU or any other additional resources which Strategist is forced to accept; note that combustion turbine, combined cycle, and coal with carbon sequestration alternatives were available to be chosen by Strategist. I already had the necessary information for the unconstrained option.

Third, I forced Strategist to add a 71 MW coal facility to the base case. I then ran the resulting scenario and 13 different contingencies. By subtracting the cost of the coal alternative case from the base case I determined the incremental cost of the coal alternative. Fourth, I allowed Strategist to add any facilities that it chose. I then ran the resulting scenario and 13 different contingencies. By subtracting the cost of the unconstrained alternative case from the base case I determined the incremental cost of the unconstrained alternative.

Q. What were the results of your cost analysis of non-renewables?

A. The results of my cost analysis are summarized below in Table 3.

Table 3 : MNGP EPU and the Non-Renewable Alternatives (PVSC $,000)

	MNGP EPU with Steam Dryer	Coal Alternative	Unconstrained Alternative
Main Case	$ -	$375,464	$329,184
$4 CO2	$ -	$284,892	$283,116
$30 CO2	$ -	$446,136	$357,432
Coal – 20%	$ -	$375,448	$324,168
Coal + 20%	$ -	$375,464	$334,160
Capacity + 3%	$ -	$374,960	$328,224
Capacity + 5%	$ -	$373,216	$326,264
Low Externalities	$ -	$375,208	$328,800
Gas – 20%	$ -	$377,584	$293,432
Gas + 20%	$ -	$373,120	$364,712
High Load	$ -	$386,920	$374,424
Low Load	$ -	$375,680	$294,920
Nuke – 20%	$ -	$386,272	$339,984
Nuke + 20%	$ -	$363,136	$316,856

Q. What do you conclude from this information?

A. I conclude that the MNGP EPU is the least cost alternative even if steam dryer replacement is necessary.

D. SOCIAL COST OF ALTERNATIVES

Q. Please explain how you performed a social cost analysis of non-renewable alternatives.

A. I used the Commission's high externality values as the standard in all analysis and ran the low externality values as a contingency scenario. In addition, I used the mid-point of the Commission's \$4 per ton to \$30 per ton cost of carbon as the standard cost for CO_2 emissions; this mid-point is \$17 per ton. Given the limits of any single number, a sensitivity analysis should be done. Therefore, for each scenario I included contingency scenarios using the Commission's \$4 and \$30 values. Therefore, the costs reported above in Tables 1 and 3 already include social costs. I also note that the Commission's value for NO_x was not used by Xcel in the Company's resource plan, which is the source for the Strategist data. Instead Xcel used a forecasted value of nitrous oxides (NO_x) permits under the Environmental Protection Agency's Clean Air Interstate Rule (CAIR). I used the same values for NO_x as Xcel. Finally, I note that the Strategist data included costs for sulfur dioxide (SO_2) and Mercury.

E. SUMMARY OF COST ANALYSIS

Q. What is your conclusion based upon this analysis?

A. Based upon the above data and analysis, I recommend that the Commission find that Xcel's Petition has met the criteria in Minnesota Rules 7855.0120B 1 to 3.

Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

September 29, 2008

The Honorable Steve M. Mihalchick
Office of Administrative Hearings
P. O. Box 64620
St. Paul, Minnesota 55164-0620

—VIA ELECTRONIC FILING—

Re: PETITION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION
FOR A CERTIFICATE OF NEED FOR THE
MONTICELLO NUCLEAR GENERATING PLANT FOR
EXTENDED POWER UPRATE
REBUTTAL TESTIMONY AND SUPPLEMENTAL DIRECT TESTIMONY
DOCKET NO. E002/CN-08-185

Dear Judge Mihalchick:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), respectfully submits the attached Rebuttal and Supplemental Direct Testimony of the following witness in the above-referenced proceeding:

- Steven W. Wishart – *Need and Alternative Evaluation*

In this filing, we acknowledge that we do not have any Rebuttal Testimony in response to the Direct Testimony submitted on September 3, 2008 by the Department of Commerce, Office of Energy Security ("OES") on behalf of its four witnesses in this case: Dr. Steve Rakow, Susan L. Peirce, Hwikwan Ham and Christopher T. Davis. However, we would like to supplement the record with additional Testimony by Mr. Wishart, in which he explains the effect of updating a number of Strategist inputs.

The updated analysis involve changes in Strategist model input assumptions used in both our December 14, 2007 Resource Plan filing (Docket No. E002/RP-07-1572) and our February 14, 2008 Certificate of Need ("CON") filing for the proposed extended power uprate at the Monticello Nuclear Generating Plant. These changes include a revised demand growth forecast and the incorporation of a number of other modifications requested by the OES in the Resource Plan proceeding. The analysis of the forecast and other modifications as outlined in the attached Testimony leave us assured that the

Monticello power uprate project is the most economically and environmentally beneficial project for meeting our projected resource needs.

A copy of this filing is also being served via e-mail or postal mail upon the persons on the attached service list. A courtesy copy is being provided to you via U. S. Mail. Please contact me at (612) 330-5641 or Brian.R.Zelenak@xcelenergy.com if you have any questions regarding this submission.

Sincerely,

/s/

BRIAN R. ZELENAK
MANAGER, REGULATORY ADMINISTRATION

Enclosures

cc: Service list

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company,
a Minnesota Corporation ("Xcel Energy"),
Authorizing an Extended Power Uprate
at the Monticello Nuclear Generating Plant

MPUC Docket No. E002/CN-08-185
OAH Docket No. 12-2500-19613-2

Exhibit___

SUPPLEMENTAL TESTIMONY OF STEVEN W. WISHART ON BEHALF OF XCEL ENERGY IN LIEU OF REBUTTAL

September 29, 2008

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven W. Wishart. My business address is 414 Nicollet Mall (MP7), Minneapolis, Minnesota 55401-1993.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. I have filed Direct Testimony in this proceeding on behalf of Northern States Power Company ("Xcel Energy" or "the Company"), a Minnesota corporation.

II. SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Supplemental Testimony is two fold. First, I would like to confirm Xcel Energy does not have any Rebuttal Testimony in response to the Direct Testimony of the four witnesses of the Office of Energy Security ("OES"): Dr. Steve Rakow, Susan L. Peirce, Hwikwan Ham and Christopher T. Davis.

Second, I would like to supplement the record and discuss the September 5, 2008 Reply Comments filed by Xcel Energy in regards to our proposed 2007 Resource Plan (Docket No. E002/RP-07-1572). In those Reply Comments, the Company presented an updated analysis of our Preferred Plan.

Q. WHY WAS A NEW ANALYSIS PERFORMED AND THE PREFERRED PLAN UPDATED?

A. While updating a number of items in our analysis that were pointed out by the OES, we also decided that it was appropriate to update the analysis with the new forecast now available. The new forecast incorporates the downturn in economic conditions as well as our increased commitment to demand-side management ("DSM"). These two variables affect the amount of renewable energy required to meet the Minnesota Renewable Energy Standard ("RES"). The combined effect of the lower forecast, increased DSM and lower renewable requirements could have an effect on what type of generation is needed and when it is needed. The analysis included a number of changes in certain input assumptions used in Strategist. I will describe these revisions in greater detail in the following sections of my testimony.

Q. WHAT IS THE RELEVANCE OF THE CHANGES IN THE INPUT ASSUMPTIONS USED IN THE STRATEGIST ANALYSIS TO THIS PROCEEDING?

A. The inputs used in the Strategist analyses performed in this Certificate of Need ("CON") proceeding are the same as those used in our initial December 2007 Resource Plan filing. Those inputs and analyses are the basis for the OES' June 16, 2008 comments to the Minnesota Public Utilities Commission ("Commission") on our Resource Plan and submitted by OES witness Hwikwan Ham (Exhibit____(HKH-3)) in this proceeding. Thus, any changes to the Strategist inputs are applicable to both the 2007 Resource Plan and our CON filing.

On September 5, 2008, we submitted Reply Comments in the Resource Plan docket that revisited our load forecast, increased our commitment to DSM and incorprated a number of other changes to our Strategist modeling so as to follow the OES' June 16, 2008 recommendations to our 2007 Resource Plan.

To be consistent, we are taking this opportunity to provide the same updated information in this proceeding as it applies to our Certificate of Need request and to reaffirm our conclusion that the proposed extended power uprate at the Monticello plant performs best both economically and environmentally over other alternatives considered.

Q. DO THE STRATEGIST INPUTS THAT WERE CHANGED AND THE UPDATED ANALYSIS AFFECT YOUR REQUEST FOR A CERTIFICATE OF NEED IN THIS PROCEEDING?

A. No. The changes made do not have a significant impact on our analysis. The updated analysis still indicates that the Monticello Extended Power Uprate project is the best option available to meet the need – from both a financial and an environmental perspective.

III. STRATEGIST MODIFICATIONS AND UPDATES

Q. WHAT TYPES OF CHANGES WERE MADE IN STRATEGIST AND WHY?

A. The changes made can be separated into four categories.

1. A new forecast that reflects the downturn in the economy and thus electric sales including updated loss factors;
2. A commitment to increase demand-side management savings from 1.1 percent to 1.3 percent over the next few years;
3. Incorporation of the June 16, 2008 comments of the Office of Energy Security in our 2007 Resource Plan; and
4. Other Strategist modifications.

Q. PLEASE EXPLAIN EACH TYPE OF CHANGE IN MORE DETAIL.

A. 1. *Forecast*: Since we filed our Resource Plan in December of 2007, we have seen a drop in our current sales, with further reductions projected in our demand and energy forecasts.

We have also re-estimated the energy loss factors used to calculate the losses associated with the sales forecast. The new loss factors are based on the five-year historical average loss factors for the time period 2003-2007. These new loss factors are lower than the factors previously used, resulting in a lower forecast of losses and, therefore, a lower forecast of total energy sales. The updating of the loss factors accounts for one-fourth to one-third of the overall change in the forecast of total energy.

Our September 2008 forecast reflects both the updated economic assumptions and energy loss factors. The latest energy forecast is 2,347 GWh lower in 2012 and 3,888 GWh lower in 2023 than the energy forecast developed for our December 2007 filing. The peak demand forecast is 374 megawatts ("MW") lower in 2012 and 613 MW lower in 2023 than the previous forecast.

2. *DSM*: Our updated DSM proposal starts at 1.15 percent savings in 2010 and grows to 1.3 percent annual savings by 2012. This results in a 1,880 MW (15 percent) reduction in peak load in 2022 and an energy reduction of 5,740 GWh.

3. *OES Comments*: On June 16, 2008, the OES issued comments on our 2007 Resource Plan. Those comments are included in this record as Exhibit____(HKH-3) to OES Witness Hwikwan Ham's Direct Testimony. In

its comments, the OES identified eight issues (page 19) that should be included in the Strategist base case. They were:

- Calculation of the real discount rate;
- Use of the Commission's externalities costs in the base cases versus via a sensitivity analysis;
- Use of the Commission's $/ton for CO_2 emissions;
- Mercury emission rates at the Black Dog coal and gas-fired generating plant;
- Dispatch cost for CO_2, SO_2, NO_x and Hg;
- Emergency energy costs in 2042-2047;
- Use of 50/50 demand forecast instead of 90/10 demand forecast;
- Use of maximum dependable capacity ("MDC") rating instead of uniform rating of generation equipment ("URGE") rating.

These eight issues were addressed and modeled as recommended by the OES in our updated analysis.

4. *<u>Other Strategist Modifications</u>*: Since the filing of the Certificate of Need on February 14, 2008, the Company has moved from the Mid-Continent Area Power Pool ("MAPP") reserve-sharing group to the Midwest/Midwest Independent Transmission System Operator ("MISO") group. This move changed our reserve planning standards, and thus, we have refined our evaluation of reserve margins and our strategy for compliance. We made some small modifications to our estimates of accredited capacity and revised our strategy for short-term capacity purchases.

We have also updated Strategist to include revised in-service dates for some wind projects and a slightly reduced total wind expansion plan. The lower load forecasts resulting from changed economic conditions and increased DSM savings have reduced the amount of wind necessary to meet the RES. Our December 2007 Resource Plan filing and our February 14, 2008 Monticello CON filing included approximately 2,900 MW of wind additions. Our revised plan includes 2,600 MW.

We also took the opportunity to update Strategist to reflect the higher construction and fuel costs we are seeing in the market now as compared to when the CON was prepared and filed earlier this year under the different economic conditions.

Finally, the Company used the OES' suggested $17/ton for CO_2 and performed a sensitivity analysis using $4/ton and $30/ton to comply with the Commission's December 21, 2007 Order establishing estimates of the future cost of CO_2 regulations (Docket No. E999/CI-07-1199).

Q. SHOULD THERE BE ANY CONCERNS OVER THE INTRODUCTION OF A NEW FORECAST AFTER THE OES HAS EVALUATED AND PROVIDED COMMENTS ON A DIFFERENT, HIGHER FORECAST?

A. No. After incorporating the new forecast and all the other modifications mentioned above, the updated Strategist results still indicate that the power uprate project is the most cost-effective alternative and will significantly reduce the Company's CO_2 emissions. The sensitivity analysis presented in Table 6-7 of the February 2008 Certificate of Need demonstrated that the Monticello power uprate was the lowest-cost alternative under numerous input assumptions. Exhibit____(SWW-1), Schedule 2 replicates Table 6-7 using the Strategist model with updated assumptions including the new lower forecast. Once again, the Monticello power uprate project is shown to be the lowest-cost option available under the base set of assumptions and under multiple sensitivities. The reason that the project is so robust to changes in the underlying assumptions is that it provides low cost CO_2 free energy that provides a hedge to fluctuations in gas and coal markets. The power uprate is an ideal addition to the Company's generation portfolio, and it does not rely on significant load growth to justify its benefit. The additional energy form Monticello will replace more expensive and CO_2 intensive energy elsewhere in the Xcel Energy system, and the load growth only increased its value by increasing the demand for clean base load energy.

IV. UPDATED ANALYSIS

Q. WHAT ARE THE AGGREGATE EFFECTS ON THE ANALYSIS OF THE CHANGES MADE AND DISCUSSED ABOVE?

A. The overall present value revenue requirement ("PVRR") for the Monticello power uprate is slightly lower than originally stated in the CON, as indicated in Table 1.1

Table 1.1: PVRR Comparison

	Original Filing PVRR ($000)	Updated Filing PVRR ($000)
Monticello Power Uprate	$61,674	$59,456
Unconstrained (Natural Gas Combustion Turbine)	+169	+196

Coal Purchased Power Agreement (PPA)	+273	+240
Biomass Plant	+514	+432

As illustrated in Table 1.1, in comparing the PVRRs of the analysis contained in our original filing to the updated analysis, while the overall PVRR for the power uprate is slightly lower, and the PVRR for the coal purchased power agreement ("PPA") and Biomass facilities actually decreased, all three of the alternatives continue to have significantly higher PVRRs than the power uprate.

Q. WHAT WERE THE MAIN DRIVERS FOR THE DECREASED PVRRS?

A. As we explained in the Resource Plan Reply Comments, overall PVRRs went down due to lower load forecast (includes increased DSM savings and loss factors) and lower CO_2 cost assumptions (from $20 to $17).

The PVRR difference between the Monticello power uprate and the unconstrained (gas CT) scenario is a little larger, because this scenario relies on mostly gas energy to replace the energy from Monticello, and our natural gas price assumption went up about $1.

The PVRR difference between the coal PPA and the Biomass option went down a little. This is primarily caused by lower CO_2 cost assumptions (and to a lesser extent, other emissions).

Q. HOW WERE THE ENVIRONMENTAL IMPACTS AFFECTED BY THE STRATEGIST CHANGES?

A. As demonstrated by Table 1.2, the net effect was a slight reduction in carbon emissions for each of the three alternatives as compared to the proposed power uprate project. However, even with the slight reduction in CO_2 of each of the alternatives, this reduction is immaterial when comparing to the power uprate project - which does not emit any carbon.

Table 1.2: CO_2 Comparison

Increase in CO_2 (Tons)	**Original Filing PVRR ($000)**	**Updated Analysis PVRR ($000)**
Monticello Power Uprate	0	0
Unconstrained (Natural Gas Combustion Turbine)	+6,376,480	+5,244,472
Coal PPA	+12,247,950	+11,952,224
Biomass Plant	+25,090,410	+24,827,490

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The Company has reviewed the testimony of the OES witnesses and does not have any Rebuttal Testimony. However, we would like to inform the parties in this proceeding that we have incorporated into our updated analysis in this proceeding some changes requested by the OES in our Resource Plan. Our updated analysis of the Monticello power uprate project, considering the changes (new lower forecast due to economic changes, use of a 50th percent forecast instead of the 90th percentile forecast, increased DSM savings, new loss factors, change in generation ratings and reserve margin, generic construction and fuel cost increases, and the other miscellaneous items identified by the OES), confirms our conclusion that the proposed Monticello power uprate project is the most economically and environmentally beneficial project for Xcel Energy to pursue. The minimal impact of the numerous changes and the results of multiple sensitivities analysis only confirm the robustness of our analysis.

Sensitivity Analysis

	Preferred Plan	71 MW Coal PPA	71 MW Biomass	Unconstrained (Natural Gas CT)
	PVRR	**PVRR Differences from the Monticello Uprate Project**		
Base Assumptions	$59,456	+ $240	+ $432	+ $196
Low Load	$56,988	+ $329	+ $492	+ $214
High Load	$62,356	+ $265	+ $457	+ $235
Coal+20%	$60,529	+ $271	+ $432	+ $203
Gas+20%	$61,605	+ $236	+ $433	+ $216
Nuclear+20%	$59,882	+ $226	+ $418	+ $182
Coal-20%	$58,392	+ $209	+ $432	+ $188
Gas-20%	$57,270	+ $244	+ $432	+ $167
Nuclear-20%	$59,030	+ $254	+ $446	+ $210
Externalities High	$59,973	+ $240	+ $433	+ $197
Externalities Low	$59,614	+ $240	+ $433	+ $197
CAIR / CAMR Permit Costs	$59,529	+ $269	+ $433	+ $204
CO2 $4	$55,732	+ $165	+ $278	+ $154
CO2 $30	$63,111	+ $315	+ $586	+ $229
MISO ON	$59,124	+ $241	+ $435	+ $227
Capital Cost ecsl 3%	$60,899	+ $238	+ $436	+ $188
Capital Cost escl 5%	$63,430	+ $237	+ $435	+ $167

Expansion Plan with EPU

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	CT_F 160	CC 627	NUKE 1000	OW09 100	CWSQ 420
2008	8660.3	9894.4	0	0	0	0	0	0	0
2009	8744.5	9991.8	0	0	0	0	0	0	0
2010	8820.3	10065.9	0	0	0	0	0	0	0
2011	8870.6	10234	5355.6	0	0	0	0	0	0
2012	8950.9	10257.5	3231.1	0	0	0	0	0	0
2013	9028.1	10334.2	1292.4	0	0	0	0	1	0
2014	9100.3	10493.5	1452.4	0	1	0	0	1	0
2015	9183.8	10848.4	2434.5	0	0	0	0	1	0
2016	9258.9	10762.8	1292.4	0	0	0	0	1	0
2017	9324.6	10773	1292.4	0	0	0	0	1	0
2018	9390	10750.8	1292.4	0	0	0	0	1	0
2019	9451.2	10853.6	2744.9	0	1	0	0	2	0
2020	9493.9	10874.9	2584.9	0	0	0	0	2	0
2021	9534.6	10983.1	1292.4	0	0	0	0	1	0
2022	9620.4	11351.3	1919.3	0	0	1	0	1	0
2023	9797.2	11344.6	3877.3	0	0	0	0	3	0
2024	9937.4	11724.6	3211.8	0	0	1	0	2	0
2025	10051.7	11546.6	2079.3	0	1	1	0	1	0
2026	10191.7	12061.7	2546.2	0	0	2	0	1	0
2027	10302.8	11794.1	2584.9	0	0	0	0	2	0
2028	10465.1	12017.7	1612.4	0	2	0	0	1	0
2029	10587.9	12152.3	1452.4	0	1	0	0	1	0
2030	10730	12423.8	1612.4	0	2	0	0	1	0

Expansion Plan with LCM Only

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	CT_F 160	CC 627	NUKE 1000	OW09 100	CWSQ 420
2008	8660.3	9894.4	0	0	0	0	0	0	0
2009	8744.5	9991.8	0	0	0	0	0	0	0
2010	8820.3	10065.9	0	0	0	0	0	0	0
2011	8870.6	10234	5355.6	0	0	0	0	0	0
2012	8950.9	10257.5	3231.1	0	0	0	0	0	0
2013	9028.1	10334.2	1292.4	0	0	0	0	1	0
2014	9100.3	10425	1452.4	0	1	0	0	1	0
2015	9183.8	10779.9	2434.5	0	0	0	0	1	0
2016	9258.9	10694.3	1292.4	0	0	0	0	1	0
2017	9324.6	10704.4	1292.4	0	0	0	0	1	0
2018	9390	10818.3	1452.4	0	1	0	0	1	0
2019	9451.2	10921.1	2744.9	0	1	0	0	2	0
2020	9493.9	10942.3	2584.9	0	0	0	0	2	0
2021	9534.6	11050.6	1292.4	0	0	0	0	1	0
2022	9620.4	10990.5	1452.4	0	1	0	0	1	0
2023	9797.2	11548.1	4504.2	0	0	1	0	3	0
2024	9937.4	11363.9	2584.9	0	0	0	0	2	0
2025	10051.7	11614	2546.2	0	0	2	0	1	0
2026	10191.7	11700.9	2079.3	0	1	1	0	1	0
2027	10302.8	11997.6	3211.8	0	0	1	0	2	0
2028	10465.1	12085.2	1452.4	0	1	0	0	1	0
2029	10587.9	12219.7	1452.4	0	1	0	0	1	0
2030	10730	12355.3	1452.4	0	1	0	0	1	0

Difference Due to Addition of EPU

YEAR	PEAK LOAD MW	INSTALLED CAPACITY MW	NEW CAPACITY MW	DEF CAPACITY MW	CT_F 160	CC 627	NUKE 1000	OW09 100	CWSQ 420
2008	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0
2014	0	68.5	0	0	0	0	0	0	0
2015	0	68.5	0	0	0	0	0	0	0
2016	0	68.5	0	0	0	0	0	0	0
2017	0	68.6	0	0	0	0	0	0	0
2018	0	-67.5	-160	0	-1	0	0	0	0
2019	0	-67.5	0	0	0	0	0	0	0
2020	0	-67.4	0	0	0	0	0	0	0
2021	0	-67.5	0	0	0	0	0	0	0
2022	0	360.8	466.9	0	-1	1	0	0	0
2023	0	-203.5	-626.9	0	0	-1	0	0	0
2024	0	360.7	626.9	0	0	1	0	0	0
2025	0	-67.4	-466.9	0	1	-1	0	0	0
2026	0	360.8	466.9	0	-1	1	0	0	0
2027	0	-203.5	-626.9	0	0	-1	0	0	0
2028	0	-67.5	160	0	1	0	0	0	0
2029	0	-67.4	0	0	0	0	0	0	0
2030	0	68.5	160	0	1	0	0	0	0