**Minnesota Public Utilities Commission**

*Staff Briefing Papers*

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**Meeting Date:** October 25, 2012

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**Company:** Xcel Energy (Xcel or the Company)

**Docket No.** E002/RP-10-825

In the Matter of Xcel Energy’s 2011-2025 Integrated Resource Plan

**Issues:** Should the Commission approve for planning purposes Xcel Energy’s 2011-2025 resource plan?

**Staff:**

Sean Stalpes .......................... 651-201-2252
Susan Mackenzie .......................... 201-2241

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**Relevant Documents**

- Xcel Resource Plan, Initial Filing (public and non-public) .................................................. August 2, 2010
- University of Minnesota Comments ................................................................. March 31, 2011
- City of Mankato Comments ........................................................................ August 12, 2011
- Calpine Corporation Comments .................................................................. August 12, 2011
- Greater Mankato Growth Comments .......................................................... August 12, 2011
- enXco Comments ......................................................................................... August 12, 2011
- Xcel Resource Plan Update ................................................................. December 1, 2011
- Prairie Island Indian Community Comments ........................................... December 12, 2011
- Xcel Resource Plan Update—Corrections ................................................ February 8, 2012
- Alan Muller Comments .................................................................................. June 5, 2012
- Carol Overland Comments ........................................................................ June 5, 2012
- Prairie Island Indian Community, Supplemental Comments ..................... June 12, 2012
- Xcel Large Industrials Comments ................................................................. June 12, 2012
- Minnesota Chamber of Commerce Comments ....................................... June 12, 2012
- Calpine Corporation, Supplemental Comments ......................................... June 12, 2012
- Department of Commerce Comments ............................................................. June 12, 2012
- Environmental Intervenors Comments ......................................................... June 12, 2012
- Applied Energy Innovations Comments ......................................................... August 6, 2012
Minnesota Chamber of Commerce Reply Comments ........................................... August 13, 2012
Environmental Intervenors Reply Comments ..................................................... August 13, 2012
Calpine Corporation, Reply Comments ............................................................... August 13, 2012
Greater Mankato Growth Reply Comments ..................................................... August 13, 2012
Department of Commerce Reply Comments .................................................... August 13, 2012
Prairie Island Indian Community, Reply Comments ........................................... August 13, 2012
Xcel Energy, Reply Comments .......................................................................... August 13, 2012
Calpine Corporation, Comments ...................................................................... August 20, 2012
Calpine Corporation, Reply Comments .............................................................. September 6, 2012

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Introduction

According to Minn. Rule 7843.0100, Subp. 9.: 

“Resource plan’ means a set of resource options that a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs.”

Minn. Rules part 7843.0500, subp. 3B states that: 

“In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:

A. maintain or improve the adequacy and reliability of utility service;
B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
C. minimize adverse socioeconomic effects and adverse effects upon the environment;
D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.”

Furthermore, a utility is “only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements.”

The purpose of a resource plan is to strengthen a utility’s long term planning processes by providing input from the public, regulatory agencies, and the Commission. Integrated resource planning (IRP) was developed to ensure that utilities evaluate supply- and demand-side resources such that a “least cost” resource plan is selected. By its nature, a resource plan is a “big picture” evaluation of the future, not a study of customer class rate impacts. If the IRP process is performed correctly, the result will be the least cost plan, which in turn implies reasonable rates for all customers.

Other Commission dockets such as certificate of need provide information on individual projects but do not necessarily help the Commission and stakeholders understand how and why a particular project was selected. By contrast, a resource plan can provide that planning information but not specific project approvals. Furthermore, Commission approval or rejection of a resource plan does not extend to particular generation projects that are currently under review in other proceedings or will be subject to review under future proceedings. Instead, it is a general finding that the plan filed by a utility appears to be reasonable, or not.

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1 In specific circumstances in which a large energy facility is proposed in the resource plan and likely to begin construction prior to filing of the utility's next resource plan, the Commission is to conduct the resource plan proceeding consistent with 216B.243. In this particular instance, approval of the facility within the resource plan would negate the need for a separate certificate of need process (see Minn. Stat. 216B.2422, subd. 6).
The Commission’s decision in a resource plan may be “officially noticed or introduced into evidence in related Commission proceedings;” however, according to Minn. Rules 7843.0600, Subp. 2., a finding or decision in a resource plan would constitute “prima facie evidence” in the related proceeding. Therefore, conclusions and findings of fact in a resource plan can still be rebutted, and such prima facie evidence is not conclusive, nor irrefutable.

**Relevant Statutes**

Statutes such as the following would be part of a utility’s analysis in resource plan proceedings:

*Environmental externalities.* Originally passed by the legislature in 1993 and codified in Minn. Stat. §216B.2422, subd. 3, the statute requires the Commission “to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation.” The law requires each utility to use the values in conjunction with other external factors when evaluating resource options in all proceedings before the Commission.

*Carbon values.* Passed by the legislature in 2007, Minn. Stat. §216H.06 requires the Commission to establish, by January 1, 2008 and updated annually thereafter, an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation to be used in all electric generation resource acquisition proceedings.

*Minnesota CO₂ Goal.* Minn. Stat. §216H.02 established goals of achieving a 15 percent reduction in CO₂ emissions from 2005 levels by 2015, a 30 percent reduction by 2025, and an 80 percent reduction by 2050.

*Conservation.* Minn. Stat. §216B.2421, subd. 1c(d), amended in 2007, requires that the Commissioner of the Department of Commerce may not approve a CIP (Conservation Improvement Program) plan that provides for an annual savings goal of less than one percent of gross annual retail energy sales. Minn. Stat. 216B.2401 states that it is the energy policy of the state to achieve annual energy savings of 1.5 percent.

*Renewable energy.* Minn. Stat. §216B.1691, amended in 2007, establishes renewable energy obligations and standards. Minn Stat. §216B.2422 requires a resource plan to include low and high load growth scenarios and scenarios that evaluate meeting 50 percent and 75 percent of future resource needs using demand-side management and renewable resources. Minn. Stat. §216B.2422, Subd. 4, prohibits the Commission from approving a nonrenewable energy facility in a resource plan unless the utility has demonstrated that a renewable energy facility is not in the public interest.

*Greenhouse Gas Control Plan.* Passed in 2007, Minn. Stat. §216H.03 states that, in the absence of federal or state laws requiring enforceable limits on CO₂ emissions, no new large energy facility can be constructed within the state, commit to import from outside the state, or enter into a long-term PPA, power that would contribute to statewide power sector carbon dioxide emissions (with a number of exemptions and exceptions).

*C-BED Goal.* Under Minn. Stat. §216B.1612 subd. 5(b), a resource plan must include a description of efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.
Initial August 2010 IRP Filing

Northern States Power Company (NSP)-Minnesota is one of Xcel Energy’s four regulated operating companies. NSP-Minnesota serves approximately 1,400,000 electricity customers in Minnesota, primarily in the Twin Cities. NSP-Minnesota also operates in North Dakota and South Dakota. NSP-Minnesota purchases power generated by Manitoba Hydro, wind, and other renewable resources in Minnesota and the Midwest.

NSP-Minnesota will also be referred to as Xcel Energy, Xcel, or the Company throughout this document.

Existing Resources

NSP-Minnesota’s system has about 7,100 MW of Midwest Independent System Operator (MISO)-accredited generation capacity. Approximately 35 percent of the capacity is generated from coal, 33 percent is from natural gas and oil resources, and 18 percent from nuclear.

<table>
<thead>
<tr>
<th>Plant</th>
<th>Fuel</th>
<th>Capability (MW)</th>
<th>Year Built</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allen S. King</td>
<td>Coal</td>
<td>510</td>
<td>1968</td>
</tr>
<tr>
<td>Angus Anson</td>
<td>Natural Gas / Oil</td>
<td>346</td>
<td>1994, 2005</td>
</tr>
<tr>
<td>Black Dog</td>
<td>Coal / Natural Gas</td>
<td>506</td>
<td>1950s</td>
</tr>
<tr>
<td>Blue Lake</td>
<td>Natural Gas / Oil</td>
<td>790</td>
<td>1970s</td>
</tr>
<tr>
<td>Granite City</td>
<td>Natural Gas</td>
<td>52</td>
<td>1960s</td>
</tr>
<tr>
<td>High Bridge</td>
<td>Natural Gas</td>
<td>495</td>
<td>2008</td>
</tr>
<tr>
<td>Inver Hills</td>
<td>Natural Gas</td>
<td>282</td>
<td>1970s</td>
</tr>
<tr>
<td>Key City</td>
<td>Natural Gas</td>
<td>52</td>
<td>1960s</td>
</tr>
<tr>
<td>Monticello</td>
<td>Nuclear</td>
<td>564</td>
<td>1971</td>
</tr>
<tr>
<td>Prairie Island</td>
<td>Nuclear</td>
<td>1,100</td>
<td>1973, 1974</td>
</tr>
<tr>
<td>Red Wing</td>
<td>Refuse-derived fuel</td>
<td>24</td>
<td>1949</td>
</tr>
<tr>
<td>Riverside</td>
<td>Natural Gas</td>
<td>484</td>
<td>2006</td>
</tr>
<tr>
<td>Sherburne County (Sherco)</td>
<td>Coal</td>
<td>1,900</td>
<td>1970s</td>
</tr>
<tr>
<td>Wilmarth</td>
<td>Refuse-derived fuel</td>
<td>19</td>
<td>1987</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>7,124</strong></td>
<td></td>
</tr>
</tbody>
</table>
As part of Xcel Energy’s Metro Emissions Reduction (MERP) projects, those coal facilities which have been converted to natural gas are Xcel’s High Bridge (repowered in 2008) and Riverside (2006) plants.

Xcel is expecting to retire Key City and Granite City in 2013 and 2018, respectively.

1. **Renewable Energy**

As of the 2010 filing, Xcel had over 2,370 MW of installed renewable capacity (19 percent of energy servicing NSP-MN and NSP-WI), including:

- 1,270 MW of wind generation;
- 812.5 MW of hydro, including a 500 MW contract with Manitoba Hydro that expires on April 30, 2015;
- 290 MW of biomass generation; and
- 1 MW of solar, which is expected to grow to 20 MW “in a decade.”

2. **Transmission**

According to Xcel, “Existing capacity on the transmission system remains constrained.” The Commission has approved certificates of need for the Phase I CapX2020 lines, and Xcel continues to participate in the MISO stakeholder process in the development of its Multi-Value Projects (MVP lines). Xcel discusses the following projects in Chapter 10 of their initial filing as those which will alleviate congestion constraints and enable the transmission of renewable energy.

<table>
<thead>
<tr>
<th>Project</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monticello-St. Cloud (CapX Fargo Project)</td>
<td>• Route permit issued by MN PUC on July 12, 2010</td>
</tr>
<tr>
<td></td>
<td>• In-service December 20, 2011</td>
</tr>
<tr>
<td>Fargo-St. Cloud (CapX Fargo Project)</td>
<td>• Route permit issued by MN PUC on June 24, 2011</td>
</tr>
<tr>
<td></td>
<td>• Route permit issued by ND PSC on September 12, 2012</td>
</tr>
<tr>
<td>Brookings-Hampton (CapX Brookings Project)</td>
<td>• Route permit approved by MN PUC on April 12, 2012</td>
</tr>
<tr>
<td>Bemidji-Grand Rapids</td>
<td>• Route permit issued November 5, 2010</td>
</tr>
<tr>
<td>Big Stone South-Brookings County (MISO MVP Project)</td>
<td>• Approved by MISO as an MVP in December 2011</td>
</tr>
</tbody>
</table>
Xcel’s Five-Year Action Plan

In general, Xcel’s initial (2010) five-year action plan included the following actions:

- Replace 270 MW of generating capacity at Black Dog 3 and 4 with a 700 MW natural gas, combined cycle unit in 2016;
- Develop a plan to update or replace Sherco 1 and 2;
- Evaluate all options to meet peaking requirements that may materialize between 2015 and 2020;
- Achieve a DSM savings goal of 1.3 percent, and work with stakeholders to achieve 1.5 percent;
- Issue an RFP for up to 250 MW of wind to be developed by the end of 2012.

The figure below shows Xcel’s 2010 IRP proposal:

<table>
<thead>
<tr>
<th>Year</th>
<th>Planned Additions</th>
<th>Combined Cycle</th>
<th>Combustion Turbine</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>Merecourt Wind 150 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sherco 3 13 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>Monticello 71 MW</td>
<td></td>
<td></td>
<td>250 MW</td>
</tr>
<tr>
<td>2013</td>
<td></td>
<td></td>
<td></td>
<td>100 MW</td>
</tr>
<tr>
<td>2014</td>
<td>PI Unit 1 82 MW</td>
<td></td>
<td></td>
<td>100 MW</td>
</tr>
<tr>
<td>2015</td>
<td>MH 725 MW extension</td>
<td></td>
<td></td>
<td>100 MW</td>
</tr>
<tr>
<td></td>
<td>PI Unit 2 EPU 82 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>Black Dog 680 MW CC</td>
<td></td>
<td></td>
<td>100 MW</td>
</tr>
<tr>
<td></td>
<td>Retire BD units 384 270 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td></td>
<td></td>
<td></td>
<td>100 MW</td>
</tr>
<tr>
<td>2018</td>
<td></td>
<td></td>
<td></td>
<td>100 MW</td>
</tr>
<tr>
<td>2019</td>
<td></td>
<td></td>
<td></td>
<td>100 MW</td>
</tr>
<tr>
<td>2020</td>
<td></td>
<td></td>
<td></td>
<td>390 MW 200 MW</td>
</tr>
<tr>
<td>2021</td>
<td>MH 125 MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td></td>
<td></td>
<td>195 MW</td>
<td>200 MW</td>
</tr>
<tr>
<td>2023</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td></td>
<td></td>
<td>195 MW</td>
<td>200 MW</td>
</tr>
<tr>
<td>2025</td>
<td></td>
<td>730 MW</td>
<td>382 MW</td>
<td>200 MW</td>
</tr>
</tbody>
</table>

1. Wind

In the 2010 filing, Xcel estimated that approximately 1,150 MW of wind generation would be needed to meet the Company’s 2020 RES requirement. Xcel’s 2010 Wind Expansion Plan included:

- issuing a Request for Proposals (RFP) “to seek up to 250 MW of wind power by the end of 2012;”
- adding 400 MW between 2013 and 2016; and
- adding 500 MW between 2017 and 2020

Xcel noted that their Wind Expansion Plan (WEP) would largely coincide with federal tax incentives. As shown in the table below, the federal wind production tax credit (PTC) is a major driver in Xcel’s strategy for wind procurement:

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2 PI = Prairie Island, MH = Manitoba Hydro, BD = Black Dog
2. Hydro

On June 10, 2010 Xcel filed a Petition for approval of three agreements, to work together as a single transaction, to increase the summer season capacity obtained from Manitoba Hydro to 725 MW. This contract would have terms extending through 2025. There are also terms in the agreement which could increase the capacity supply to 850 MW, beginning in May 2021.

December 2011 Update to the Initial Filing

Xcel filed their 2011-2025 resource plan on August 2, 2010. Economic conditions, ongoing assessment of Black Dog 3 and 4, extended power uprate changes at Prairie Island, and changes to the Company’s wind procurement strategy were major drivers which led to Xcel filing an Update to the Resource Plan on December 1, 2011.

Xcel’s Update assumed slower economic growth and the loss of wholesale customers. According to Xcel’s response to DOC Information Request #149, more than 200 MW of capacity in municipal loads departed from Xcel’s system since the initial filing. Therefore, Xcel’s forecast for demand and energy were reduced, which changed the Company’s resource needs. The revised resource needs by year is shown in the figure below:

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3 The Commission approved this Petition with conditions and clarifications in Docket No. 10-633.
Adjustments to the Company’s forecast and its assumptions resulted in the following action plan discussed in the 2011 Update:

<table>
<thead>
<tr>
<th>Year</th>
<th>NG CC unit</th>
<th>NG CT unit</th>
<th>Nuclear</th>
<th>Wind</th>
<th>Hydro</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>690</td>
<td>720</td>
<td>656</td>
<td>686</td>
<td>303</td>
</tr>
<tr>
<td>2013</td>
<td>71 MW @ Monticello</td>
<td>58 MW @ Prairie Island</td>
<td>725 MW Manitoba Hydro expansion</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>200-500 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2021</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2023</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2024</td>
<td>58 MW @ Prairie Island</td>
<td>58 MW @ Prairie Island</td>
<td>195 MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>729 MW</td>
<td>729 MW</td>
<td>729 MW</td>
<td>729 MW</td>
<td>729 MW</td>
</tr>
</tbody>
</table>

As shown in the table above, Xcel’s proposed expansion plan includes:
- An extended agreement with Manitoba Hydro to receive 725-850 MW of hydro through 2025;
• 187 MW of increased capacity at the Monticello and Prairie Island nuclear facilities;
• Five 195 MW combustion turbines, one each in 2018, 2019, 2020, 2023, and 2024 (the combustion turbines in 2018 and 2019 are part of a replacement plan for not pursuing the Black Dog Repowering Project);
• One 729 MW natural gas combined cycle unit in 2025; and
• No coal or wind units beyond 2012.

Xcel’s updated five-year action plan includes:
• Withdrawing the Certificate of Need request for the Black Dog Repowering Project;
• Retiring existing Black Dog Units 3 and 4 by 2016, since the updated forecast indicates the units are no longer needed;
• Completing the capacity uprate project for Monticello;
• Proceeding with the Prairie Island uprate; and
• Reassessing the Company’s wind acquisitions, largely due to the expectation that the federal production tax credits will expire at the end of 2012.

Xcel set its resource planning DSM level at 1.3 percent DSM savings, but the Company will work with stakeholders to achieve 1.5 percent savings. Xcel achieved the 1.5 percent savings in 2011, but believes it will be difficult to sustain the 1.5 percent goal over the planning period, primarily due to energy efficiency market saturation.

Assumptions and Modeling Changes

Xcel made several modeling changes in the 2011 Update. Xcel’s revision of its median peak demand and energy forecast resulted in several changes to its proposed resource plan and was a significant driver in prompting the 2011 Update. The system peak demand forecast was reduced from a growth rate of 1.1 percent in the 2010 IRP to 0.7 percent in the 2011 Update. The base energy forecast was reduced from a growth rate of 0.9 percent in the 2010 IRP to 0.5 percent in the 2011 Update. Xcel attributes these changes largely to a reduced GDP forecast.

Xcel adjusted its baseline wind assumption to reflect an expiration of the federal wind PTC after 2012. Xcel also included an updated wind capacity accreditation value based on MISO’s wind capacity credit (12.9 percent in 2011).

Xcel also changed its baseline CO₂ value from $17/ton with an escalation rate to $0/ton. However, Xcel modeled CO₂ value sensitivities at the Commission’s mid- and high-level estimates, plus a “late” CO₂ scenario with costs starting in 2018.

Xcel updated the cost and performance assumptions of its existing fleet as well.

Black Dog

Primarily due to downwardly shifted economic projections, Xcel revised its forecast such that the Company does not expect to need resources until 2018 (as shown in Figure 3.11 on page 10 of this document). Instead, Xcel expects to add “one or two more peaking units” rather than pursue the Black Dog Repowering Project.
Xcel provided in the 2011 Update results of a scenario analysis comparing combustion turbines to the Black Dog project. In general, the savings from the Black Dog project exist in years 2030 and beyond, but Xcel believes combustion turbines are the most cost-effective strategy in the next 20 years. The table below shows the Black Dog project’s Present Value Revenue Requirements (PVRR) by decade. The numbers in parentheses indicate a negative PVRR, or project savings.

<table>
<thead>
<tr>
<th>PVRR Deltas-$millions</th>
<th>2011-2020</th>
<th>2021-2030</th>
<th>2031-2040</th>
<th>2041-2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base BDCC 2018</td>
<td>($6)</td>
<td>$104</td>
<td>$31</td>
<td>($68)</td>
</tr>
<tr>
<td>High Gas</td>
<td>($36)</td>
<td>$100</td>
<td>$21</td>
<td>($79)</td>
</tr>
<tr>
<td>Low Gas</td>
<td>$32</td>
<td>$109</td>
<td>$46</td>
<td>($57)</td>
</tr>
<tr>
<td>Low CO2</td>
<td>($40)</td>
<td>$101</td>
<td>$18</td>
<td>($79)</td>
</tr>
<tr>
<td>Mid CO2</td>
<td>($72)</td>
<td>$99</td>
<td>$7</td>
<td>($89)</td>
</tr>
<tr>
<td>High CO2</td>
<td>($164)</td>
<td>$80</td>
<td>($25)</td>
<td>($113)</td>
</tr>
<tr>
<td>Late CO2</td>
<td>($82)</td>
<td>$103</td>
<td>$8</td>
<td>($97)</td>
</tr>
<tr>
<td>High Load</td>
<td>($70)</td>
<td>$37</td>
<td>($12)</td>
<td>($44)</td>
</tr>
<tr>
<td>Low Load</td>
<td>$227</td>
<td>$186</td>
<td>$199</td>
<td>($63)</td>
</tr>
</tbody>
</table>

As shown above, savings exist by pursuing the Black Dog project in almost all sensitivities. However, these savings are largely accrued in 2031-2050. Xcel reasons that, since savings are not expected to be realized during the planning period, and since longer term projections are generally less reliable and more uncertain than short-term projections, the Company proposes to withdraw its certificate of need for the project in order to conduct further analysis.

The scenario analysis Xcel conducted indicates the Black Dog Repowering Project may still “prove to be the best alternative for meeting customers’ medium-to long-term needs.” Xcel proposes to continue to “thoroughly address the 2016 to 2018 planning horizon” in the Company’s next resource plan.

**Prairie Island**

Xcel’s initial filing in August 2010 included a 164 MW uprate at the Prairie Island nuclear facility, with two 82 MW capacity increases scheduled for 2014 and 2015. The initial filing indicated that capacity increases could provide $500 million of benefits. The 2011 Update concluded that a Change in Circumstances proceeding would be necessary.4

Both capacity and cost information changed since the initial filing. On the capacity estimates:
- In the Company’s initial filing, Xcel proposed to uprate Prairie Island by 164 MW in 2014-2015.
- In October 2010, Xcel increased the capability at Prairie Island by 18 MW, due to “enhanced precision in monitoring,” leaving 146 MW of capability yet to be increased.
- In the 2011 Update, Xcel scaled back the potential capacity increase by 29 MW.

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4 The Notice of Changed Circumstances was filed on March 30, 2012 in Docket No. E002/CN-08-509.
Thus, Xcel found that only a 117 MW increase at Prairie Island could feasibly be realized, instead of 164 MW proposed in the initial filing. Xcel’s five-year plan, as of the 2011 Update, includes the 117 MW uprate as two 58 MW increases in 2014 and 2015.

On the cost side, Xcel calculates that “the total cost of the [uprate] will be approximately $250 million, $187 million of which can be avoided if [Xcel] were to terminate the program.” While Xcel still maintains the uprate will have an economic benefit, the expected value has greatly diminished.

Monticello

Xcel’s initial filing in August 2010 also included a 71 MW uprate at the Monticello nuclear facility. Xcel expected the Monticello uprate to be completed by 2011, but the 2011 Update delayed the Company’s target date to 2013.

Sherco 3 Update

The 800 MW Sherco Generating Station Unit 3 is jointly owned by Xcel (59 percent) and Southern Minnesota Municipal Power (41 percent). On November 19, 2011, Sherco Unit 3 experienced a “significant failure” while returning to service following a scheduled maintenance overhaul. Xcel noted that the failure caused major damage to the unit, and Xcel stated an investigation into the cause of the equipment failure was being conducted.

Xcel plans to open a new docket for future reports so that any updates related to the Sherco 3 outage can be reviewed in a separate proceeding.

Wind Update

Since the 2010 filing, Xcel added about 330 MW of wind, and the Company expects to add at least 200 MW in 2012. These additions would result in 1,800 MW of wind in total on Xcel’s system. Xcel also noted a possibility of another 300 MW before the PTC’s scheduled expiration.

Solar Update

Xcel’s 2011 Update indicated they “may have up to 4.2 MW of solar capacity” by the end of 2011. About 3 MW was added under the Company’s Solar*Rewards program. Xcel noted that “over 30 percent of the capacity installed under this program is from panels manufactured in Minnesota.”\(^5\) Xcel proposed a goal of 20 MW of solar by the end of the planning period.

Future Renewables Needs

\(^5\) Staff note: On June 1, 2012, Xcel stated the Company’s intention to end the Solar*Rewards program by the end of 2013.
Minn. Stat. §216B.1691, subd 2b establishes the Renewable Energy Standard (RES) that Xcel must meet through 2025. Specifically, Xcel is required to meet renewable energy targets of:

- 15 percent by 2010
- 18 percent by 2012
- 25 percent by 2016
- 30 percent by 2020

In addition, Minnesota’s RES requires Xcel Energy to have 25 percent of the electricity it provides at retail come from wind energy by 2020.

Xcel discusses its strategy for utilizing Renewable Energy Credits (RECs) on Page 50 of their Update:

“With our planned wind energy additions, we will have sufficient renewable generation by the end of 2012 to utilize banked RECs for several years. We expect to have RECs sufficient to satisfy our RES requirements through approximately 2020. If the additional wind generation discussed above [referring to the 300 MW] is added to our system prior to the end of 2012, we could have adequate RECs available to meet our requirements through around 2023.”

Xcel has approximately 7,300,000 banked RECs to carry into future years of RES compliance. Assuming no additional wind additions, the following table shows the RECs Xcel already has banked (#2), the RECs Xcel expects to generate (#3), the RECs needed for compliance (#5), and the REC surplus at the end of each year (#6).

<table>
<thead>
<tr>
<th>Compliance with Renewable Targets, without Additional Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
</tr>
<tr>
<td>---------------------------------</td>
</tr>
<tr>
<td>1. NSP Retail Sales</td>
</tr>
<tr>
<td>2. Banked RECs at Beginning of Year</td>
</tr>
<tr>
<td>3. RECs Generated During Year</td>
</tr>
<tr>
<td>4. RECs Generated During Year as a % of NSP Retail Sales</td>
</tr>
<tr>
<td>5. RECs Needed for Compliance (all jurisdictions)</td>
</tr>
<tr>
<td>6. Banked RECs After Full Compliance (2+3-5)</td>
</tr>
</tbody>
</table>

The federal PTC is a per-kilowatt-hour tax credit. The wind PTC credit amount is 2.2 cents/kWh, or $22/MWH, and the PTC is expected to expire at the end of 2012.

In the 2011 Update, Xcel stated their intention to take advantage of the PTC through the end of 2012, assume the PTC’s expiration, and then modify the Company’s five-year action plan to reassess their wind strategy after 2012. However, while the 2011 Update indicated a cessation of wind additions post-2012, Xcel explains that they will probably need to add wind at some point in the latter years of the planning period to comply with renewables obligations.
Compliance with EPA Regulations

Xcel foresees the Mercury and Air Toxics Standards (MATS) rule to have the most significant impact on its operations. MATS will limit emissions of mercury, acid gases, and other hazardous air pollutants from power plants.

Xcel identified Black Dog Units 3 and 4 and Sherco 1 and 2 as units which will be impacted by MATS. MATS would also apply to the King Plant and Sherco 3, but Xcel does not expect that additional controls are required for compliance at either unit.

According to Xcel’s evaluation of the EPA regulations’ impact on Black Dog 3 and 4:

“We evaluated the costs of retrofitting these units to comply with the [MATS] and other pending EPA regulations. Based on our analysis, including an assessment of the compliance costs and the units’ age, we concluded it would not be in our customers’ best interests to continue operating these units using coal. Instead, we developed plans to switch these two units to natural gas-only operations prior to the compliance deadline. We expect to ultimately retire these units and replace them with new natural gas generation but, as described in this update, decisions about the size and timing of that replacement generation are still pending.”

Xcel expects to retrofit Sherco 1 and 2 with pollution controls instead of retiring the units. Xcel states the most cost-effective strategy for Sherco 1 and 2 would be to control mercury via Activated Carbon Injection technology, and to control particulate matter with a new wet electrostatic precipitator.

Additional Updates and Filings

Xcel’s CIP Triennial Plan

Xcel’s proposed electric savings goals are at 1.38 percent for each year of the Triennial Plan. Xcel’s proposed gas savings goals are at the minimum 1.0 percent level in each year of the Triennial Plan.

A recent DSM potential study for Xcel’s electric service territory, completed by KEMA, shows a large decrease in market potential starting in 2014, resulting from market saturation of retrofit measures and increases in codes and standards. The KEMA potential study evaluated incremental cost scenarios with various levels of rebates for energy efficiency measures.7

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6 Staff note: The MATS rule finalized in December 2011, published in the Federal Registrar in February 2012, and became legally in effect in April 2012. Utilities will have three years to comply with MATS (April 2015).

7 Staff note: The incremental costs are evaluated with respect to a baseline. For example, a program that provides an incentive to a customer to upgrade to a high-efficiency refrigerator would use the premium of that refrigerator over the base model that would otherwise have been purchased.
According to the KEMA study, even where 100 percent of the incremental cost is covered by a rebate, a 1.5 percent savings goal is not attainable in 2015:8

<table>
<thead>
<tr>
<th>KEMA Potential Study Results</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>50% Rebate</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>75% Rebate</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>100% Rebate</td>
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</table>

As shown in the table above, at rebate levels of 50, 75, and 100 percent of the incremental cost of energy efficiency measures, the 2013-15 average savings potential ranges from about 1.5 to 1.7 percent.

On October 1, 2012, the Department of Commerce Commissioner issued a Decision on Xcel’s Triennial CIP. According to the Deputy Commissioner’s decision in Xcel’s Triennial CIP, “Xcel’s proposed electric and gas 2013-2015 CIPs are in compliance with the minimum energy savings requirement (§216B.241, subd. 1c(b)).”9

The Commerce Commissioner also required Xcel to continue Solar*Rewards after 2013 into 2014 and 2015 with the same budget in the 2010-2012 Triennial CIP, but with the reduced incentive level of $1.50/watt.

**Prairie Island Uprate Notice of Changed Circumstances**

Xcel filed a “Notice of Changed Circumstances and Petition Related to Prairie Island Extended Power Uprate,” in this docket on April 2, 2012 and on March 30, 2012 in Docket No. 08-509 (the Prairie Island Uprate Docket). The Notice of Changed Circumstances noted that Xcel was placing its Prairie Island nuclear plant uprate project on hold, based on forecasts of future generation needs in the entire system, the costs of alternative resource options, and uncertainties in the federal licensing process.

**ALJ Motion on Black Dog Repowering Project**

On May 30, 2012 Administrative Law Judge Richard Luis issued his Order Granting Motion to Withdraw and Order to Certify (ALJ Order). The ALJ Order:

- granted Xcel’s motion to withdraw its Certificate of Need (CN) Petition;
- granted Xcel’s request to certify its motion to the Commission; and
- certified to the Commission the Company’s Withdrawal Motion.

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8 Xcel’s DSM potential study can be accessed on the Company’s website at [http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Regulatory_Filings/MN_DSM](http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Regulatory_Filings/MN_DSM)

Xcel argued, and the ALJ agreed, that referring the Motion to Withdraw to the Commission would allow the Commission to provide input and guidance to, and restructure and clarify goals of, the CN proceeding. Xcel’s position was that the Commission’s decision on the Prairie Island Uprate, and on the Motion to Withdraw the Black Dog CN, may need to be considered in a proceeding that can examine the size, type and timing of its next resource addition, and all related issues.

The ALJ concluded that Xcel’s reasoning was sound. According to the ALJ, “The need for future energy capacity that would have been supplied by the Black Dog Project, the uprates at Prairie Island and Monticello, and any circumstances surrounding Sherco 3, are all appropriately under consideration in the Integrated Resource Planning Docket for 2011-2025.”

DOC recommended that Xcel should not be allowed to withdraw the Company’s CN Petition. The Department cited forecasting uncertainties and the status of Sherco 3 as the bases for the need to repower Black Dog 3 and 4.

Calpine Corporation recommended denying Xcel’s Motion to Withdraw on the basis that it would be in appropriate to decide within the context of the contested case whether Xcel’s updated forecast information showed a need for the additional Black Dog generation.

The ALJ did not agree with Calpine’s argument that the CN proceeding is mandated by law and necessary to address the need initially identified by Xcel. According to the ALJ:

“Calpine argues that granting NSP’s Motion to Withdraw, because NSP now cannot support the need for the Black Dog project, is inappropriate. The Administrative Law Judge does not agree. Indeed, if updated forecasts led the Company to make a decision that it will not have a need for the additional capacity to be provided by the Black Dog Project in 2016, there is no legal reason to bar the Company from withdrawing its Application.”

Party Positions

List of intervening parties

The intervening parties which provided comments in Xcel’s resource plan included:

- Calpine Corporation
- Campus Beyond Coal (University of Minnesota-Twin Cities)
- City of Mankato
- Department of Commerce
- enXco
- Environmental Intervenors10
- Greater Mankato Growth
- Minnesota Chamber of Commerce
- Minnesota Solar Companies and Organizations11

11 Minnesota Solar Companies and Organizations consist of: Minnesota Solar Energy Industries
Individuals providing comments in Xcel’s resource plans included:

- Carol Overland
- Alan Muller
- Dustin Dension, Applied Energy Innovations

The Commission received a large number of public comments, most of them supporting greater use of solar, other renewables, and conservation in Xcel’s resource mix. These comments included a letter with 624 names of Xcel customers supporting increased use of solar energy, letters from 610 customers supporting replacing Sherco 1 and 2 with solar, and a letter from approximately 10 student organizations supporting increased use of solar and other clean energy.

**Department of Commerce**

*(Staff note: This section incorporates the modeling from DOC’s reply comments. All contingencies in DOC’s initial comments included CO₂ prices, but the reply comments repeated the modeling by running Strategist again without CO₂. DOC’s recommendations for Xcel’s IRP are the same even when CO₂ costs are removed.)*

The Department recommends that the Commission require Xcel to:

1. Continue to pursue the uprate at Prairie Island;
2. Continue to pursue the uprate at Monticello;
3. Pursue 100 MW to 200 MW of wind in 2015-2016 if the price is $50 per MWh or less;
4. Procure 400 MW to 600 MW of natural gas capacity in 2017-2018, at least half of the natural gas capacity should be CC;
5. Procure a 1.3 percent level of DSM;
6. Use short term purchases to fill any capacity needs in 2015 - 2016; and
7. Require Xcel to continue working with the Department to fully address the forecasting issues prior to Xcel submitting any certificate of need or rate case filing

In addition, the Department recommends approval of Xcel’s base energy forecast and the Department’s peak demand forecast for planning purposes only.

**DOC’s Modeling Approach**

DOC’s first step in evaluating utilities’ modeling in resource plans is to try to replicate how a utility arrived at their proposed expansion plan. DOC ran the commands from the 2011 Update provided by Xcel through Strategist to conduct the analysis, and DOC was able to successfully replicate Xcel’s modeling.
After DOC successfully replicated Xcel’s model, DOC made changes to Xcel’s baseline assumptions to establish the Department’s own base case. Some of the modifications were:

1. increasing the number of potential plans that could be run and saved by Strategist to 5,000;
2. inserting the Commission’s CO$_2$ internal cost estimate of $21.50/ton mid-point value;
3. removing the wholesale market from Strategist. The Department’s policy in past resource plans has been not to rely upon the wholesale market to meet demand at the median forecast;
4. forcing a short-term wholesale market purchase for 2017 and 2018 when Xcel will have a small capacity deficit;
5. making wind units optional rather than as a forced addition as modeled by Xcel. In DOC’s base case, wind units were modeled at a flat price of $65 per MWh to reflect the potential for the federal wind production tax credit to expire; and
6. fixing perceived errors in Xcel’s modeling, such as operation and maintenance outage requirements, a changed discount rate to reflect the weighted average rate of return from Xcel’s last rate case, and mercury emissions to track.

Once a base case is established, the Department develops several scenarios, which can restrict Strategist from choosing a particular resource (e.g. a No New Wind scenario), force Strategist to consider a particular resource (e.g. a baseload unit), or force certain amounts of resources (e.g. variations of DSM). DOC then runs several contingencies to evaluate how different circumstances (e.g. different natural gas prices, the Commission’s range of CO$_2$ values, etc.) affect each scenario.

DOC’s analyses use ranges of information available to the Department at the time of their modeling. The preferred plan indicated by DOC’s Strategist modeling is, generically, one which minimizes costs, recognizes state and federal laws and regulations, and considers social impacts.

Third, DOC runs an extensive scenario analysis. A change in one contingency may or may not affect the selection of resources in Strategist’s outputs. Therefore, acknowledging a 15-year planning period will inevitably result in unforeseen changes to electricity demand, fuel prices, and environmental regulation, DOC incorporates a robust range of contingencies to assess what a utility’s system would look like in hundreds of different futures. Specifically, DOC looks at how sensitive the Strategist model is to changing assumptions, the frequency distribution of contingencies, and the probability of possible futures when making recommendations.

Incorporating DOC’s changes to Xcel’s modeling, the Department presented its base case expansion plan in Table 3 of their comments.\textsuperscript{12}

\textsuperscript{12} Staff comment: When reviewing the number of unit additions, it is useful to be aware of the size of the unit. As shown in Table 2, baseload units are 465 MW, intermediate (CC) units are 354 MW, peaking (CT) units are 190 MW, and wind units are 200 MW.
DOC’s base case expansion plan is split roughly evenly between peaking and intermediate capacity. In the 2016-2018 timeframe, about 500 MW of natural gas is added. Xcel’s base case installs mostly peaking combustion turbines from 2018-2024, and a combined cycle intermediate unit is installed at the back end of the planning period. DOC’s base case also adds 200 MW of additional wind.

Scenario Analysis

Including the base case, DOC ran 15 different scenarios, each with 34 different contingencies (510 possible futures). The 15 scenarios were:

1. DOC’s base case
2. RES Required (the Minnesota RES is assumed to be met)
3. High DSM (Xcel is assumed to meet the 1.5 percent DSM goal)
4. Mid-high forecast
5. High forecast
6. No power uprate at Prairie Island
7. No power uprate at Monticello
8. No Manitoba Hydro uprate in 2021
9. No Sherco 3 unit (assume the unit does not come back from its current extended forced outage)
10. Sherco 1 and 2 units shut down in 2015
11. Sherco 1 and 2 units shut down in 2016
12. Sherco 1 and 2 units shut down in 2017
13. Keep the Key City units;
14. Keep the Granite units
15. Terminate the mandated biomass PPAs

(In their reply comments, DOC re-ran the model setting CO2 to $0, which could be considered a 16th scenario.)

Among the contingencies run in each scenario were:
• carbon prices ranging from delayed until 2020 to $34/ton in all planning years;
• coal price ranges at 10 and 20 percent lower and higher than the base case;
• natural gas prices studied in 50 cent increments from $1.50 lower to $2.50 higher than the base case;
• wholesale market allowed; and
• wind prices studied in $5 per MWh increments from $35/MWh to $80/MWh.

1. **Prairie Island**

DOC’s analysis showed that the impact of removing the uprate at Prairie Island is “relatively minor.” When the Prairie Island uprate was removed, under most contingencies, Strategist selected either 1) wind for energy and a combustion turbine for capacity or 2) a combined cycle unit for capacity and energy as a replacement plan.

The Prairie Island uprate was the least cost approach under all contingencies except when natural gas prices were consistently 20 percent lower than Xcel’s base case assumption. If low natural gas prices occur, the uprate is projected to be more expensive by between $1.2 and $6.1 million, or about 0.002 percent to 0.009 percent.

DOC’s analysis showed that neither CO₂ cost assumptions nor delay in the timing of the uprate would impact whether the uprate was selected as the preferred option.

Therefore, DOC recommends the Commission continue to pursue the Prairie Island uprate.

2. **Monticello Uprate**

The Monticello uprate has been approved by the Commission in Docket No. 05-123, but the issue is still pending before the Nuclear Regulatory Commission (NRC). DOC’s analysis found the Monticello uprate to be “highly cost-effective.” Similar to the Prairie Island uprate, DOC concluded the impact on the expansion plan of removing the uprate at Monticello is “relatively minor” with the lost (nuclear) energy being replaced by wind.

DOC recommends the Commission continue to pursue the Monticello uprate.

3. **Pursue 100 MW to 200 MW of wind in 2015-2016 if the price is $50 per MWh or less**

DOC required Strategist to add sufficient wind so that enough renewable energy is produced to meet the Minnesota RES percentage in each year. The RES was cost effective at wind prices up to about $45-$50 per MWh.

The $45-$50 per MWh price point assumes $21.50/ton CO₂ prices, Xcel’s base natural gas prices, Xcel’s demand forecast, and all other inputs for the Department’s base case. However, DOC’s no-CO₂ cost scenario analysis did not significantly impact the price at which wind becomes cost effective, which indicates that factors such as load shape, wind production patterns, and coal unit minimum capacities appear to be of greater influence.
4. **Procure 400 MW to 600 MW of natural gas capacity in 2017-2018, at least half of the natural gas capacity should be CC**

DOC’s scenarios (listed on p. 20) consistently added natural gas capacity in the 2016-2019 timeframe, but there were several combinations of combustion turbine and combined cycle additions. As examples:

- DOC’s base case added a combustion turbine in 2016 and a combined cycle unit in 2018.\(^{13}\)
- Removing the Prairie Island uprate typically added an additional combined cycle unit.
- DOC’s 75\(^{th}\) percentile forecast typically added two combustion turbines in 2016 with a combined cycle in 2018.
- Retiring the Sherco units involved combined cycle units, doubled in size, and an additional combustion turbine.

The Department’s no-CO\(_2\) cost analysis did not fundamentally change the natural gas expansion plan in the near term. However, the no-CO\(_2\) cost scenario did change the timing in which the first combined cycle unit was added to the base case, that year being 2024 without CO\(_2\). Still, the next five plans with the lowest Present Value Revenue Requirement (PVRR) added a 400 MW combined cycle between 2018 and 2019.

DOC notes, though, that their position is to include CO\(_2\) in resource planning, which results in the 2017-2018 natural gas addition to be least cost. DOC ran the no-CO\(_2\) scenario to provide a more comprehensive analysis. Furthermore, since Xcel is unsure about whether to pursue the Prairie Island uprate, and since the Company is evaluating the replacement of Sherco 1 and 2, the Department recommends procurement of 400-600 MW of natural gas capacity in the 2017-2018 time frame.

5. **Procure a 1.3 percent DSM level**

In resource plans, DOC makes DSM recommendations based on the most likely contribution to system reliability in the context of least-cost planning. Through the CIP process, DOC works with utilities to maximize DSM levels, but resource plans are evaluated based on which expansion plans have the lowest PVRR.

Xcel proposes a long-term energy-savings goal equal to 1.3 percent of its retail sales. DOC’s modeling indicates that the 1.3 percent amount of DSM has a lower PVRR than the 1.5 percent level under base case conditions and in all but one of the contingencies (the CO\(_2\) reduction contingency).

Part of the reason that higher levels of DSM result in a higher PVRR is because Xcel has a lot of energy. Thus, given that the additional energy savings and associated capacity savings were not enough to replace any supply-side resources, the 1.5 level of DSM had a higher PVRR than Xcel’s proposed 1.3 percent level.

Typical unit changes of the higher DSM levels include:

- No changes (10 contingencies); or

\(^{13}\) In DOC’s Strategist runs, combustion turbine units are 190 MW, and combined cycle units are 354 MW.
• 200 MW of additional wind (10 contingencies); or
• One additional combustion turbine, and a subtraction of 200 MW of wind (7 contingencies).

6. Sherco

Xcel has announced a return to service date for Sherco 3 of the first quarter of 2013. DOC’s analysis showed that it was “highly cost-effective” for Xcel to return Sherco 3 to service.

The impact of the scenario assuming Sherco 1 and 2 retire in 2015, 2016, or 2017 would impose significant costs on Xcel’s system from $0.7 to $2.6 billion, except for the natural gas no growth contingency.

According to DOC’s analysis, “there would have to be substantial environmental compliance and/or life cycle maintenance costs for replacing Sherco 1 and 2 to be a viable consideration.” Overall, excluding CO₂ costs from the model still resulted in Sherco 1 and 2 being “highly cost-effective” units to continue to operate.

Environmental Intervenors

The Environmental Intervenors (EIs) consist of: the Izaak Walton League of America – Midwest Office, Fresh Energy, Sierra Club, and the Minnesota Center for Environmental Advocacy.

The EIs conclude the following:
1. Xcel’s IRP did not include the statutorily required least-cost analysis for replacing 50 percent and 75 percent of new and refurbished capacity with renewables and energy efficiency
2. Xcel’s IRP is not consistent with Minnesota’s greenhouse gas reduction goals as defined under Section 216H
3. Xcel’s coal price assumptions are unjustified
4. The Commission should order Xcel to fund a study to evaluate increased solar penetration
5. Xcel does not plan for all cost-effective energy efficiency and demand response

The EIs express several concerns with Xcel’s IRP, but are perhaps most concerned with delays in the process. Therefore, the EIs do not recommend rejection of the plan, as it would cause further delay, but instead recommend the Commission approve the resource plan subject to the following conditions:
• Completion, within 6 months, of a study that evaluates retirement and replacement of Xcel’s coal resources, particularly Sherco 1 and 2;
• Completion and approval of the above study as condition precedent for Xcel’s filing of any future rate case;
• Completion of an increased solar penetration study;
• Public filing of a study to determine how to access all cost-effective demand response
• Provision of relevant discovery (including Strategist files) to the EIs;
• Approval of Xcel’s plan to discontinue use of coal at Black Dog by 2015;
• Establishment of the state’s 1.5 percent energy efficiency goal in the planning period; and
• Requirement that future IRP filings include least cost plans that meet the 50 percent and 75 percent renewables/conservation requirement
1. Statutory Requirements

50/75 percent renewables and energy efficiency scenarios

The Els’ position is that Xcel’s resource plan is premised on refurbishment of its Sherco 1 and 2 units to meet certain federal environmental standards. Not comparing the refurbishment costs to that of renewable resources expansion fails to comply with Minn. Stat. § 216B.2422, subd. 2, which requires resource plans to include a “least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.”

Specifically, the plan relies on the Sherco units beyond dates by which the units will require environmental compliance, particularly the MATS rule. Because Sherco will need to undergo “refurbishment” to comply with MATS and possibly the cooling tower rule, the Els argue that “Xcel cannot credibly assert that Sherco will not require ‘substantial modification’ during the planning period for purposes of this IRP.”

Minnesota’s Greenhouse Gas Reduction Goal

The Els also contend the Xcel’s IRP is not consistent with Minnesota’s greenhouse gas reduction goals, as defined under Section 216H.02 of Minnesota statutes. Section 216H is a statewide goal to reduce greenhouse gas emissions to at least:

- 15 percent below 2005 levels by 2015;
- 30 percent below 2005 levels by 2025; and
- 80 percent below by 2050

Under Xcel’s preferred plan, the Company’s greenhouse gas emissions will be 23 percent below the 2005 baseline by 2015, but only 15 percent below by 2025. The Els contend Xcel’s projected growth in greenhouse gas emissions by the end of the planning period is inconsistent with the statewide goal.

2. Coal Prices

The Els contend Xcel’s coal price assumptions are inconsistent with historical delivered coal prices, unjustified in the reasons for why they are lower, and thus provide an unreasonable advantage to the continued operation of Xcel’s existing coal fleet.

Xcel provided the Els with the Company’s Power River Basin Coal Resource and Cost Study in response to Information Request MCEA 73. The Els believe the PRB Coal Study does not support Xcel’s assumed future coal prices, nor does it support the coal price escalation rates used in the IRP.

3. Future Studies

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14 Minnesota Office of the Revisor of Statutes, 216B.2422, Resource Planning; Renewable Energy
15 Environmental Intervenors comments, page 9.
The EIs recommend the Commission require Xcel to provide supplemental analyses to the Company’s next resource plan.

First, the EIs recommend the Commission order Xcel to develop a baseload diversification study for Sherco 1 and 2, similar to those ordered to be completed by Minnesota Power\textsuperscript{16} and Otter Tail Power.\textsuperscript{17} The EIs describe Xcel’s modeling as “limited” with respect to Sherco 1 and 2, and the EIs “strongly suggest” the Sherco units to be subject to additional analysis. Moreover, the EIs condition their recommendation for approving Xcel’s instant resource plan on the future development of the Sherco study.

According to Xcel’s responses to the EIs’ Information Requests (IR) \#55 and \#57, the EIs note that “across many of Xcel’s sensitivities, the decision to retire Sherco 1 and 2 in 2017 rather than retrofit it is nearly equal on a PVRR basis.”\textsuperscript{18}

Xcel’s response to the EIs’ IR \#81, the Company preliminarily projects the following costs for pollution controls at Sherco 1 and 2:

- **2012-2016: \$33 million**
  - \$11 million for a new Wet Electrostatic Precipitator for particulate matter controls;
  - \$10 million for a Sparger installation projects for SO\textsubscript{2} control
  - \$12 million for mercury controls

- **2017-2020: \$254 million**
  - \$254 million for a Selective Catalytic Reduction NO\textsubscript{X} reduction project

Thus, the EIs recommend the Commission require a study, within six months from the date of the Order, to further analyze the costs for pollution controls at Sherco 1 and 2 and to compare the retrofit costs to retiring the unit.

Second, the EIs recommend Xcel conduct a solar penetration study and file it before the Company’s next resource plan. The study should include:

- an analysis of the feasibility of a range of achievable penetration levels; and
- information on associated costs, challenges, and benefits; and
- examples of successful solar penetration initiatives implemented by utilities in other states and countries

Third, the EIs are of the understanding, based on the Company’s response to MCEA IR 71, that Xcel has completed or has nearly completed a demand response potential study. The EIs request the Commission direct Xcel to file this study in this IRP docket when it is completed.

**Minnesota Chamber of Commerce**

The Minnesota Chamber of Commerce (MCC) filed initial comments on June 12, 2012. MCC recommends to the Commission that Xcel’s IRP should \textbf{not} be approved until the plan contains the following information:

\textsuperscript{16} Docket No. 09-1088
\textsuperscript{17} Docket No. 10-623
\textsuperscript{18} Environmental Intervenors comments, page 24.
- Rate impacts by class as a result of policy mandates such as Xcel’s CIP and RES obligations
- Analyses which address such limitations of Strategist such as hour-by-hour/weekly average modeling to address Xcel’s customers’ load and energy needs
- Reevaluation of a Black Dog 3 and 4 life extension which retains the units’ coal burning capability
- Fuel acquisition and risk management strategy
- An action plan for Xcel to improve its system load factor
- Study of Combined Heat and Power (CHP) options

MCC recommends that Xcel submit a revised resource plan which includes the information listed above and discussed below.

1. **Rate impacts as a result of policy mandates**

MCC argues that Xcel’s IRP provides insufficient information regarding cost increases and rate impacts by class associated with such policies as the Company’s CIP and RES obligations. Moreover, Xcel’s IRP does not include an “off-ramp” scenario in the event of increased rates due to these policies.

Once all appropriate costs and rate impacts are considered regarding Xcel’s policy mandates, the Company should then file a revised resource plan.

2. **Strategist limitations**

MCC argues the Strategist model uses assumptions which are oversimplified to the extent that a reasonable, least-cost resource plan cannot be developed. Strategist does not incorporate fuel price volatility or customers’ load profile on an hourly or weekly basis. Therefore, these assumptions “bias the results toward certain types of supply-side resources.”

MCC recommends these Strategist limitations are addressed in Xcel’s revised resource plan.

3. **Additional wind procurement**

MCC agrees with Xcel’s decision not to include additional wind units in its preferred plan. MCC discusses several issues with wind units which compromise Xcel’s system reliability:

- The expiration of the federal wind production tax credit will further lessen wind’s economic benefit
- Wind is an incompatible replacement for baseload and/or peaking resources
- Strategist does not accurately model wind’s intermittency, costs, and benefits

4. **Black Dog 3 and 4 life extension option**

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19 MCC initial comments, page 4.
MCC recommends the Commission order Xcel to reconsider, and more thoroughly investigate, the Black Dog life extension option. MCC argues Black Dog 3 and 4 should be kept as a coal-fired baseload resource for several reasons.

First, keeping Black Dog 3 and 4 as a coal-fired resource retains fuel burning diversity and provides a hedge against volatility in natural gas markets. MCC notes that, while natural gas is currently cost competitive, history has indicated that natural gas is volatile and risky, compared to coal. Specifically, MCC states that “the demand for natural gas is expected to rise significantly due to coal retirements across the country,” which will raise natural gas prices. Therefore, Xcel’s assumptions make the Black Dogs repowering combined cycle option appear more cost-effective because of the current state of the natural gas market.

Second, MCC contends that Xcel’s analysis comparing the life extension option to the combined cycle option is “misleading” because intermediate plants do not operate the same as baseload plants. As such, upgrading Sherco, nuclear uprates, or some other baseload comparison would be more appropriate.

Third, since MCC foresees little probability that Xcel will build a new coal-fired power plant, Xcel should give stronger consideration to keeping the coal-fired power the Company has. MCC does not agree with any scenario which retires Xcel’s existing coal units. As an alternative to the retirement or repower options, MCC recommends,

“If Xcel proposes an intermediate step to burn natural gas, Xcel should provide a cost-benefit analysis of this step, and it should not be done in such a manner that constrains, eliminates, or otherwise threatens its coal-burning permits.”

In the event the Commission approves a resource plan which incorporates more natural gas, MCC recommends Xcel submit a risk management plan for approval at the Commission. In addition, Xcel should also “immediately issue an RFP for a 20-year supply contract to provide support for assumptions used.” The risk management plan would be used to include a proposed diversified portfolio including short- and long-term purchases.

**Xcel Large Industrials**

Xcel Large Industrials (XLI) filed comments discussing the Company’s compliance with Minnesota IRP rules and statutes and the IRP process in general. From XLI’s perspective, Xcel’s five-year action plan is too vague, and the cost and class rate impacts are insufficient. Additionally, XLI contends the existing resource planning process “does not work” and gets too bogged down in modeling and forecasting such that IRP dockets are largely irrelevant to ratepayers.

XLI cited Minnesota Rule 7843.0400 subp. 4, which requires utilities to include in their resource plans “a nontechnical summary...describing a utility’s resource needs...activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills.”

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20 MCC initial comments, page 12.
21 MCC initial comments, page 13.
XLI does not object that Xcel discusses how much investment is anticipated during the planning period (i.e. the PVRR metric), but XLI considers the summary insufficient in that the Company did not include a rates and bills analysis. XLI states that Xcel’s plan does not provide ratepayers or the Commission with the requisite information to determine whether the action plan demonstrates a plan’s ability to:

- maintain or improve the adequacy and reliability of utility service;
- keep the customers’ bills and the utility’s rates as low as practicable, given regulatory and other constraints;
- minimize adverse socioeconomic effects and adverse effects upon the environment;
- enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and
- limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

XLI submitted an IR requesting a cost impact by class, to which Xcel responded:

> “The forecast near term rate increases and relative cost increases by scenario are based on our long-term resource planning model and do not replicate a test-year style setting of rates. The resource planning model does not allocate rate impacts between customer classes. Thus, the level of detail that is requested by XLI assumes a level of precision that is not provided within the resource planning models.”

XLI qualified Xcel’s response as “unacceptable” and fails to comply with applicable law.

XLI requested that the Company perform a class rate impact analysis in the Company’s reply comments. XLI’s request also extended to intervening parties, specifically DOC and the EIs. XLI stated that if other intervenors had alternative five-year action plan, that party should also submit a class rate impact analysis.

XLI also cautions the Commission about approving a resource plan that lacks rate impact information and contains data which may be outdated by the time an IRP is evaluated by the Commission. XLI argues that an approved resource plan can shift the burden of demonstrating reasonable or unreasonable costs to the ratepayer. Additionally, time spent on resolving forecast issues rather than costs and rate impacts associated with procuring resources discourages customer involvement.

XLI argues that ratepayers would be better served if Minnesota “significantly modified or replaced” the present resource planning process. In the meantime, XLI recommends the Commission require utilities to submit a detailed five-year action plan with a corresponding ratepayer impact analysis and a shorter review process.

**Calpine Corporation**

Calpine recommends that the Commission accept Xcel’s Motion to Withdraw, close the Black Dog docket, and order the procurement 400-600 MW of new natural gas fired capacity in the 2017-18 timeframe, at least half of which should be combined-cycle capacity. Calpine also recommends the

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22 Minnesota Rule 7843.0500, subp. 3.
23 Xcel Response to XLI IR #2, April 21, 2011.
Commission proceed in a timely manner such that new gas-fired generating capacity can be installed by 2017.

Additionally, Calpine recommends the Commission accept the Department’s analysis in the IRP Docket as “a conclusive demonstration” of the resource need. The Department identified a need for new gas-fired generating capacity even when relying on Xcel’s lowered demand forecast, and Calpine agrees with DOC’s analysis to add a natural gas combined cycle facility.

Calpine argues that the least-cost manner in which Xcel can add this capacity is to promptly enter into negotiations for a Purchase Power Agreement (PPA) with Calpine for the Mankato Expansion “for commercial operation beginning on or before June 1, 2017.” Calpine recommends the Commission order Xcel “to present the proposed PPA for the Mankato Expansion to the Commission for approval on or before 90 days from the date of Commission approval in the IRP docket, or March 1, 2013, whichever is sooner.”

Since the Mankato Expansion represents an additional 375 MW, and Calpine agrees with the Department’s analysis for a need of 400-600 MW, Calpine also recommends Xcel to propose, within 90 days of the IRP order, “a Request for Proposals (RFP) process to solicit competitive interest in meeting the remainder of the identified need for new gas-fired capacity, for commercial operation as soon as 2018.”

However, if the Commission decides to keep the Black Dog docket active, Calpine recommends the Commission make a finding that the record demonstrates Xcel “will need 400-600 MW of new natural gas fired capacity in the 2017-2018 timeframe, at least half of which should be combined cycle generation.” Thus, a future contested case should focus on determining the least-cost procurement strategy for the 400-600 MW of natural gas capacity.

Calpine recommends the contested case be limited to only the Black Dog repowering project and Calpine’s Mankato Expansion. Moreover, the Commission “should resolve pending discovery disagreements by directing that the Administrative Law Judge use the Department in the role of an independent evaluator, and that the Department and the Commission should be the only parties with access to the respective applicants’ non-public, confidential information.”

City of Mankato / Greater Mankato Growth

The City of Mankato and Greater Mankato Growth each filed comments supporting the Mankato Energy Center as an alternative proposal to Xcel’s Black Dog repowering proposal. The 375 MW Mankato Energy Center has been operation in Mankato since 2006.

The City of Mankato also argues that Xcel’s IRP is insufficient in its lack of consideration of developing new power generating resources via competitive procurement. Since Xcel’s portfolio already contains generation acquired from competitive suppliers, the City of Mankato argues the instant IRP should have also considered competitive suppliers.

Greater Mankato Growth argues that Mankato Energy Center could be expanded to 750 MW more cost-effectively than building a new natural gas combined cycle plant. Moreover, the expansion process would add hundreds of temporary jobs and about 13 permanent jobs to the City of Mankato.
**Prairie Island Indian Community**

The Prairie Island Indian Community (Community) is particularly concerned about the inaccuracy of Xcel’s forecast in its original 2010 resource plan filing and how ongoing forecasting issues affect the amount of generation Xcel needs and when the Company needs it. The Community recommends the Commission conduct, or refer to the Office of Administrative Hearings for, an evidentiary hearing to firmly establish Xcel’s resource need.

Similarly, the Community urges the Commission to further evaluate Xcel’s Prairie Island uprate, both in this docket and a Changed Circumstances docket. The Community argues that Xcel has not sufficiently demonstrated: a need for the uprate, whether the 164 MW uprate would actually be achievable, or the environmental, public safety, and health impacts of the uprate. Moreover, since the Nuclear Regulatory Commission (NRC) has not yet approved the license amendment associated with the Prairie Island uprate, approving it may be premature.

The Community’s overall intent is to continue developing the IRP such that Xcel’s resource need is clear and confirmed. At present, the Community does not believe Xcel has a demand for additional baseload capacity which would necessitate the uprate. In addition, the Community argues that Xcel’s 2011 Update to the Resource Plan is too general to warrant approval of the Prairie Island uprate at this time.

**Carol Overland**

Ms. Overland recommends the following:

- If Xcel intends to withdraw its pursuit of the Black Dog Repowering Project, the Company should do so immediately. Moreover, the withdrawal of Black Dog should be taken into account in the resource plan.
- The Prairie Island uprate Certificate of Need should be revoked/withdrawn by the Commission, and this should be taken into account in the IRP.
- Xcel should be released from its obligations to C-BED projects for which Xcel Energy has signed PPAs, but which are not yet in operation.
- The Commission should consider order Xcel to retire Sherco 3.
- The Commission should require DSM to be increased, at a minimum, by 0.5-1.0 percent than the amount proposed by Xcel. The Commission should also require the DSM which is available to be utilized.

Ms. Overland notes that the MISO and MRO-MAPP regions have projected large surpluses of supply, and, at the same time, Xcel has revised its forecast to indicate less need. In addition, all of Xcel’s municipal wholesale customers in Wisconsin and all but one wholesale customer in Minnesota did not renew service agreements.

Ms. Overland included the NERC 2011 Long Term Energy Assessment as Exhibit A in her comments. The following table from the NERC Assessment demonstrate the expected supply surpluses in the MISO and MRO-MAPP regions:
Ms. Overland concludes that the Prairie Island uprate provides “no benefit” since both the achievable capacity projections have been lowered at the same time the projected costs have increased. Ms. Overland recommends the Prairie Island uprate certificate of need be revoked or withdrawn by the Commission, “and this should be taken into account in the IRP.”

Ms. Overland recommends that, since Xcel has been meeting its demand without Sherco 3, surplus capacity exists in the wholesale market, and forecasts indicate small increases in energy and demand growth, Sherco 3 should be retired. Repowering Black Dog prior to 2018 could cover any needs that would have been met with Sherco 3. The Black Dog repowering and Xcel’s existing DSM capability should be able to handle Xcel’s system peaks.

Ms. Overland also recommends higher levels of DSM than which Xcel proposes. The Commission should require Xcel to increase its DSM at least above 2 percent savings.

**Alan Muller**

Mr. Muller filed comments discussing Xcel’s Sherco units, DSM achievements, and renewable energy procurements.

Mr. Muller points to the reliability concerns of the Sherco 3 outage as a significant cause for further evaluation regarding the unit’s long-term viability, and whether the unit should even be returned to service. Moreover, the Commission and the public should decide, within the instant resource plan docket, the role of Sherco 3 in Xcel’s generation portfolio.

In addition, Mr. Muller contends that Xcel is seemingly avoiding investment in its Sherco 1 and 2 units. According to Mr. Muller, “The emissions of Sherco are one of the largest contributors to reduced visibility, and the [Regional Haze Plan] adopted by the Minnesota Pollution Control Agency, presumably under pressure from Xcel, are inadequate to abate these emissions.”

Mr. Muller argues that clarity is needed in Xcel’s “renewables obligations.” Sources such as refuse-derived fuel are “dirtier than coal,” and have a negative environmental impact. Mr. Muller believes the

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24 Staff emphasis added
PUC should not allow Xcel to meet its RES “in ways that mock the intent” of the statute, and the IRP should be modified to clearly identify the economic and environmental profile.

Mr. Muller also argues the IRP should be revised to incorporate a portfolio of alternatives with respect to expanded DSM. Increasing DSM would be integral to a sound risk management strategy, and clear distinctions need to be made between energy and capacity savings. Mr. Muller points to the national experience with DSM, which suggests it is a least-cost approach.

**Solar Power Manufactures of Minnesota**

A consortium of Minnesota solar power manufacturers and installers filed a letter supporting solar energy development in Minnesota and in Xcel’s IRP. The consortium noted that solar installation and manufacturing has employed thousands of Minnesotans in over one hundred businesses, mostly manufacturing, relating to solar.

The solar businesses also state that Minnesota’s solar insolation is similar to that of southern cities like Houston and Tallahassee, and thus, Minnesota is a relatively good solar resource state. However, the State of Minnesota is behind many other states, including Wisconsin, in developing solar energy.

The solar businesses identify several benefits of increasing solar energy in Minnesota. First, Minnesota utilities’ peak loads generally coincide with the peak generation of solar panels. Increasing distributed generation can offer improved reliability. Second, solar energy is not subject to cost fluctuations as is the case with more conventional fuels, such as natural gas. Diversifying energy sources benefits consumers, and solar energy, in particular, creates value by providing utilities and ratepayers with cost certainty. Third, increasing solar generation decreases greenhouse gas production.

**Dustin Dension, Applied Energy Innovations**

Applied Energy Innovations (AEI) is a Minneapolis-based mechanical, plumbing, and general contractor that installs and specializes in renewable energy and energy efficiency building integration. AEI works with Community Action Programs, rebates, grants, and home loan programs as a licensed solar installer, among other trades.

AEI discusses Minnesota’s solar potential, and notes that Minnesota has a “similar solar resource to Florida and a significantly greater solar resource than Germany.” AEI also discusses solar’s payback period, which, due to sharp drops in the installed costs of solar and federal and state tax incentives, has experienced a payback period fall “from 30 years to 10 years.”

According to AEI,

“The Solar*Rewards program was so popular that it cannot keep up with demand. These rebates have clearly shown that Minnesotans want more investment in solar, and that they are willing to invest their money in solar.”

AEI requests the Commission work with Xcel to:

1. Increase solar energy by 1,000 MW by 2025;
2. Facilitate third party ownership of solar energy; and
3. Retire Sherco 1 and 2 by 2025

University of Minnesota

The University of Minnesota\textsuperscript{26} (University) filed comments discussing their research and findings to support the expansion of biomass-based electrical capacity. The “Biomass Electricity Generation at Ethanol Plants” project (partially funded by the Xcel Energy Renewable Development Fund) analyzed the costs, logistics, and life-cycle environmental performance of using renewable biomass versus fossil natural gas or coal to power ethanol plants.

The University notes that there are currently 18 ethanol plants operating in Minnesota with a generating capability of up to 600 MW. Moreover, twelve of those plants are located in Xcel’s service area, and, collectively, the plants have a generating capacity of up to 400 MW of renewable electricity. According to the Biomass Electricity project, “the estimated delivered cost of densified corn stover was $74/ton and reduced the lifecycle GHG emissions by factors of 8 and 13 when compared to natural gas and coal, respectively.”\textsuperscript{27}

The University notes that many of the ethanol plants operating in Minnesota are well positioned to export to the grid, particularly in Xcel’s service territory. Therefore, the University recommends that Xcel’s IRP to consider adding biomass-based electrical capacity.

Campus Beyond Coal

Campus Beyond Coal (CBC) is a student-led environmental group at the University of Minnesota, Twin Cities.

CBC states the IRP “must reflect that continued investment in and dependence on coal presents not only an environmental risk to the public, but also a financial risk to Xcel.”

CBC provides a literature review discussing the impacts of climate change, market externalities of coal-fired generation, and findings from a leading scientific research authority on global climate change, the Intergovernmental Panel on Climate Change. CBC argues that Xcel should consider these environmental and economic risks in the Company’s planning.

CBC then discusses how the investments in renewable resources and demand-side management can alleviate these risks. CBC points to Minnesota’s proximity to favorable wind conditions and steep declines in the levelized costs of solar resources as opportunities to the Company.

CBC makes the following recommendations to the Commission:

- Xcel’s plan should focus on phasing out coal-fired generation. In particular, the Company should evaluate replacing its Sherco units with renewable energy and energy efficiency;

\textsuperscript{26} Comments of University of Minnesota Faculty: Douglas G. Tiffany and R.V. Morey.
\textsuperscript{27} University of Minnesota comments, Page 5.
• Xcel should add 5,000 MW of wind and 1,000 MW of solar capacity, and procure 2 percent DSM level over the planning;
• Xcel’s resource plan should appropriately incorporate financial risks of coal-fired generation and the economic opportunities of renewable energy

enXco

Renewable energy Developer, enXco, filed a dispute in response to Xcel’s Resource Plan Update, regarding the status of the Merricourt Wind Project. enXco’s letter was to make the Commission aware that enXco disputes Xcel’s reasons and rights to terminate the Merricourt Wind Project.

Xcel Energy Reply Comments

Xcel’s reply comments outline the Company’s preferred Commission order, update their resource needs assessment, discuss the IRP’s rate impacts and how rate impacts are projected in Strategist, and respond to comments of the intervening parties.

Xcel proposes that the following recommendations be included in the Commission’s order:

• Approve Xcel’s base energy and peak demand forecast as adequate for resource planning purposes.

• Direct Xcel to procure 400-600 MW of natural gas capacity in the 2017 to 2019 timeframe, but make no finding regarding the type of natural gas.

• Reassess acquiring new wind generation for the 2015 to 2016 timeframe, except if unique, high-valued opportunities arise before then.

• Submit a baseload diversification study by July 1, 2013 that examines the feasibility and cost-effectiveness of continuing to operate Sherco Units 1 and 2, in comparison to non-coal-based alternatives;

• Direct Xcel to work with interested parties to identify useful measures of rate impacts associated with the Company’s resource plans and incorporate them into the next resource plan filing; and

• Find that Xcel’s proposed DSM savings of 1.3 percent is reasonable for planning purposes.

Xcel also recommends the Commission take the following action on the Black Dog Repowering Project:

• Revise the scope of the Black Dog Repowering Proceeding (Docket E002/CN- 11-184) to identify the best plan to meet the resource need of 400 to 600 MW over the years of 2017 to 2019;
• Direct the Administrative Law Judge for the Black Dog Repowering Proceeding to protect the disclosure of confidential information related to bids from competing parties;

• Retire Black Dog Units 3 and 4 in 2015;

Xcel requests the Commission to reject the following recommendations made by intervening parties:

• Fully address forecasting issues prior to the submission of any certificate of need or rate case filing (DOC recommendation);

• Direct Xcel to conduct a solar resource study prior to submission of Xcel’s next resource plan (EIs recommendation); and

• Immediately issue an RFP for a 20-year fixed price gas contract. (MCC recommendation)

Updated Needs Assessment

The following tables show Xcel’s differences in expected resource need from the December 2011 Update to the Company’s August 2012 reply comments:
As shown from the two tables, Xcel maintains that no material differences in resource need have occurred since December 2011. While Xcel is expecting a slightly higher need forecast as of August 2012, the Company is still expecting to be long on capacity through 2015, and the need for a new facility is likely not needed until the 2017-2018 time period.

**Black Dog Units 3 and 4**

Xcel has concluded that ceasing coal operations at Black Dog 3 and 4 is the most cost-effective option to the Company, in large part to avoid incurring major capital expenses to comply with proposed and finalized environmental regulations.

To comply with EPA’s MATS rule by February 2015 at Black Dog Units 3 and 4, Xcel has identified that a fabric filter baghouse, spray dryer absorber, and sorbent injection would be required to reduce particulate matter.

Both units currently have electrostatic precipitators for particulate control, which the Company has identified as insufficient for MATS compliance. The electrostatic precipitators would have to be removed and replaced with different control equipment in order for Black Dog 3 and 4 to continue operation.

Additionally, the design and limited space at the plant site would make the addition of fabric filters and flue gas scrubbers to control SO₂ “very complicated.”

Xcel also has determined that there are other upcoming environmental regulations that would require additional control equipment upgrades and construction in addition to MATS.

Based on Xcel’s updated forecast, the Company does not expect to need the Black Dog capacity in 2015 or 2016. Additional analysis evaluating the costs of staffing the facility, potentially significant repair costs, and the surplus capacity in MISO are other reasons for Xcel’s shifted position on Black Dog. If Xcel would need capacity in 2015, Xcel considers participation in MISO’s capacity market as a more economic option to provide a “capacity bridge” until the addition of another resource in later years of the planning period.

**Renewable Energy**

**Wind**

The Department recommends Xcel pursue 100 to 200 MW of additional wind in the 2015-16 timeframe if the price of the energy is $50 per MWh or less. MCC recommends that no more wind be added. Xcel considers its early procurement strategy consistent with both recommendations.

Xcel’s 2011 Update proposes no new wind in the five-year action plan, which the Company considers to be consistent with MCC’s recommendation. (As discussed in the Update, Xcel’s approach changed to add more wind by the end of 2012, before the federal tax credit expires, and none in the new five-year action plan.)
Xcel does not rule out wind procurement in the 2015-16 timeframe. However, Xcel does not necessarily agree with DOC’s $50 per MWh price point, since DOC included CO₂ in baseline assumptions of the expansion model. Xcel’s analysis concludes that, without CO₂ costs, the wind price target is about $35.50 per MWh for wind to be a cost-effective option.

**Solar**

Xcel’s solar portfolio has primarily developed from grants through the Renewable Development Fund and rebates through the Solar*Rewards program (which is included as part of Xcel’s CIP budget).

Xcel plans to phase out Solar*Rewards from CIP by the end of 2013. Xcel cites “the high cost of solar compared to other resources, rebate levels and cost-effectiveness results that are out of line with other CIP programs, and lack of an effective regulatory framework” as contributing factors to end the program.

The EIs recommend a solar resource study be conducted to further develop Xcel’s solar portfolio. Xcel disagrees with the EIs’ recommendation. Xcel instead intends to continue to evaluate solar as part of a broader distributed generation effort.

**Response to the Minnesota Chamber of Commerce**

MCC recommends that Xcel’s IRP should **not** be approved until the plan contains the following information:

- Rate impacts by class as a result of policy mandates such as Xcel’s CIP and RES obligations
- Analyses which address such limitations of Strategist such as hour-by-hour/weekly average modeling to address Xcel’s customers’ load and energy needs
- Reevaluation of a Black Dog 3 and 4 life extension which retains the units’ coal burning capability
- A fuel acquisition and risk management strategy
- An action plan for Xcel to improve its system load factor
- Study of Combined Heat and Power (CHP) options

**Five-Year Action Plan Rate Impacts**

XLI argued that Xcel’s resource plan does not satisfy state law because it is too ambiguous and omitted a definitive cost impact for the five-year action plan. MCC specifically recommended that rate impacts by class **as a result of policy mandates** be included in the resource plan. MCC also requested a comparison of our electric rates to other utilities in the state and surrounding areas.

Minn. Rules 7843.0400, subp. 2 require a utility only “to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing” and to “show the resource options the utility believes it might use to meet those needs.”

Moreover, a resource plan must also include

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28 Minn. Rules 7843.0400, subp. 2.
“activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills.”

Xcel believes the resource plan satisfies resource planning rules. Xcel argues that it would be difficult to be accurate in providing the information requested by the Chamber and XLI in a resource planning docket. For example, Strategist is the analytical tool which provides a least-cost expansion plan, determined by the lowest PVRR, over 15 years to determine the size, type, and timing considerations of resource additions. In contrast, ratemaking is much more detailed, inclusive, and typically concentrates on a single test year.

Additionally, Xcel states that “the only element of the five-year action plan that has a direct capital impact is the Prairie Island uprate, since the Company removed the Black Dog Repowering Project and wind procurement from its five-year plan.” Shown below, the incremental rate impact of the uprate is further discussed in Attachment B of Xcel’s reply comments:

As of the 2011 Update, Xcel’s estimate for the total cost of the Prairie Island uprate will be $250 million. Xcel stated they have spent “just over $60 million to get to this stage in the process;” however, “another $20 million and potentially more will be required to complete the licensing process.”

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29 Minn. Rules 7843.0400, subp. 4.
Moreover, Xcel previously noted that $187 million of costs could be avoided if the Prairie Island uprate were terminated.\textsuperscript{31} Xcel updated this value in their reply comments, stating that $237 million could be avoided if the uprate were not pursued. According to the Company, “that translates into a potential reduction in revenue requirements of $13 million in 2016 and $39 million in 2017.”

Per MCC’s request, Xcel provided rate comparisons to other states and utilities as Attachment C of the Company’s reply comments. Xcel emphasized that rate comparisons are generally not an apples-to-apples comparison of general utility rates, especially rates by customer class.

Xcel pointed to the cyclical nature of capital investment as part of the problem with comparing recent rate increases to other states or utilities. Rate comparisons, Xcel argues, do not capture differences in the stages of the capital investment cycle among utilities, particularly when viewed over a short period of time.

Additionally, rate comparisons use broad customer classes that do not correlate to the more specific customer classes Xcel uses. For example, Xcel has six customer classes, including five non-residential classes. As such, comparing six customer classes to a utility that uses three classes is not a reliable comparison, from Xcel’s view.

\textit{Fuel Acquisition and Risk Management Strategy}

MCC recommended the Commission require Xcel to file a risk management plan for fuel acquisition and issue an RFP for a 20-year gas contract to provide support for the assumptions used in Xcel’s resource plan modeling.

As part of the Settlement Agreement of the Emissions Reduction Project,\textsuperscript{32} Xcel filed an annual electric generation natural gas supply plan on March 30, 2012 to obtain a reliable and flexible supply of gas at a competitive market price. Xcel would consider expanding the current natural gas supply plan to include a risk management plan addressing natural gas price volatility; however, Xcel notes the timeline of the plan would likely be limited to 10 years, instead of 20 as recommended by the Chamber.

Xcel disagrees with the Chamber’s suggestion to immediately issue an RFP for a 20-year supply contract to provide support of assumptions used in the resource plan modeling. Xcel contends that “issuing an RFP with the sole intent of soliciting price information from the market would not be in good faith.” Also, Xcel notes that 20-year natural gas contracts are extremely uncommon if not nonexistent.

\textit{Cogeneration}

MCC recommended that Xcel examine the potential for combined heat and power (CHP) for distributed baseload generation, including specific sites, barriers and opportunities, and economic feasibility. Similar to the Company’s response to the EIs’ recommendation for Xcel to develop a solar resource study, Xcel would be willing to work with stakeholders regarding the design of an appropriate regulatory structure to address the value of distributed generation.

\textsuperscript{31} December 2011 Update, p. 34
\textsuperscript{32} Docket No. E002/M-02-633.
Response to the Environmental Intervenors

Baseload Diversification Study / Life Cycle Management Study

The EIs recommended the Commission to order Xcel to conduct a baseload diversification study—similar to those ordered for Minnesota Power, Otter Tail, and Interstate Power & Light—in order to assess the long-term viability of Sherco 1 and 2. Xcel agreed to file such a study by July 2013.33

The December 2011 Update assumed that Sherco 1 and 2 would continue to operate after the end of their book lives in 2023. Xcel is currently in the process of verifying this assumption via a “Life Cycle Management Study” the Company is conducting. Xcel stated in their reply comments that the preliminary findings of the Study suggest Sherco 1 and 2 can be “operated well beyond” 2023.

Sherco 1 and 2 both have wet scrubbers for SO₂ and ash control, a wet electrostatic precipitator for particulate emissions, and low NOₓ burners, overfire air, and combustion controls to reduce NOₓ emissions.

To meet near-term compliance requirements, Xcel expects to implement the following emissions control equipment:

- Activated Carbon Injection to control mercury emissions;
- Wet Electrostatic Precipitator to further reduce fine particulate emissions; and
- Sparger Installation Project to further reduce SO₂ emissions controls.

Xcel notes that an important unknown, at this time, is whether further NOₓ controls will be needed. If so, Xcel has identified that the Sherco units will also require Selective Catalytic Reduction (SCR) technology for NOₓ control. The timing of SCRs installation is a key component of Xcel’s ongoing Life Cycle Management Study, as is the timing for retirement in the event the aforementioned pollution control equipment is not cost-effective.34

Compliance with Statutory Requirements

The EIs contend that Xcel’s resource plan does not comply with certain statutory requirements, especially the requisite scenario analysis to supply 50 and 75 percent of new and refurbished capacity needs with renewables and conservation. The EIs’ argument is that statute requires potential retrofits at Sherco Units 1 and 2 be compared to replacing that capacity with renewables and energy efficiency.

Xcel argues that the need to refurbish Sherco 1 and 2 is uncertain at this time, and evaluation of Sherco 1 and 2 is ongoing. If Xcel definitively determines to refurbish Sherco 1 and 2, Xcel would present a least-cost 50/75 percent renewables and conservation analysis at that time. Xcel also notes that, in

33 (Xcel refers to the Study as a “Life Cycle Management Study” instead of a baseload diversification study. Staff inserted the term baseload diversification study instead of Life Cycle Management Study for consistency purposes with other dockets.)

34 Staff note: As discussed on page 25 of this document, Xcel estimated, in response to the EIs’ IR #81, that the SCR project at Sherco 1 and 2 could cost $254 million.
DOC’s initial comments, the Department concluded that Xcel applied the 50 and 75 percent analysis rule properly.

**Intervening Party Reply Comments**

**Department of Commerce Reply Comments**

**Black Dog Certificate of Need**

The Department recommends that the Commission reject Xcel’s motion to withdraw the Black Dog certificate of need petition. Instead, DOC recommends the Company maintain the 2017-2018 in-service date, “perhaps with a short delay to provide an opportunity for the bidders (Calpine and Xcel) to update their project information, if desired.”

DOC entertains the possibility of reopening the bidding to more bidders, but, like Calpine, DOC emphasizes the short timeline of adding the recommended 400 to 600 MW of combined cycle capacity. Thus, DOC recommends that any reopening to more bidders should allow for a short time period, such as 30 days, both for Xcel and Calpine to refresh their bids and for any other bidders to provide a proposal.

**Market Purchases**

The Department has a long-standing policy of recommending to the Commission that market purchases only be used in resource planning as a bridge until a resource can be procured more cost-effectively at a later date. In this case, DOC recommends that, given the timing of Xcel’s resource needs and the most cost-effective in service date for a new supply-side resource, Xcel pursue short-term market purchases in 2015 and 2016 to cover any capacity shortfalls. DOC recommends, as in their initial comments, for Xcel to procure 400 MW to 600 MW of natural gas capacity in 2017 – 2018, at least half of which should be combined cycle.

**Demand Forecast**

Xcel proposed a downward shifted demand forecast in their 2011 Update. Several intervenors also commented that certain resources are no longer needed because of changed economic conditions. DOC argues “It would not be appropriate to assume that the lower demand due to the economic downturn will continue in the long term.”

Xcel experienced a sharp drop in demand due to the recession. Xcel’s forecast was shifted downward in the Company’s 2011 Update to reflect the changed economic conditions from a slower-than-expected economic recovery. DOC contends that carrying the downward adjustment into the long-term may lead to insufficient resources, which would result in more reliance on the wholesale market.

DOC notes that the median forecast is most appropriate because it is based on historical data that includes previous economic activity, weather, etc. and ensures that enough generation will be available throughout the planning period.
Prairie Island

DOC’s baseline forecast shows generation is needed in the medium-term and that the Prairie Island uprate is the least-cost option.

Regarding Xcel’s proposal to hold a Prairie Island docket conference, DOC notes that the only issues remaining would be if the project was never approved by the NRC or if the NRC imposed changes to the design that significantly increased the costs for the uprate. It does not appear that there would be any such effect, but the Department believes it would be helpful to clarify this question. Based on the Department’s understanding at this time, the Department continues to support proceeding with the PI EPU.

Bill Impacts

DOC responds to XLI’s request for the Department to include a cost-impact analysis by class in DOC’s reply comments. The Department notes the following regarding bill impacts from resource plans.

“While Xcel likely will be able to revise its estimates of bill impacts, such estimates involve numerous assumptions about how the resources will be procured and paid for. For example, if Xcel uses a purchased power agreement (PPA) rather than owning a generation facility, the PPA costs would be recovered through the fuel clause adjustment (FCA) on a per-MWh basis. Assumptions about the terms of PPAs would be needed.

If Xcel chooses to own a generation facility, the costs will not be recovered from ratepayers until either: 1) Xcel files a rider, if applicable, or 2) there is a rate case once the facilities are used and useful. Recovery through a rate case would be based on the methods used in the class cost of service study and revenue apportionment. Thus, the estimates of bill impact that Xcel provides in IRP filings are not definitive figures but are estimates based on the Company’s plans to implement the IRP.”

DOC estimates the impacts on rates and bills by developing a least-cost plan. “Least cost” is the plan with the lowest revenue requirement over the planning period. In the Department’s initial comments, DOC’s base case projected Xcel’s inflation-adjusted system costs to increase by 12 percent.

Minnesota Chamber of Commerce Reply Comments

MCC does not believe a baseload diversification study is necessary for Sherco Units 1 and 2 at this time, for the following reasons:

- Xcel is initiating a life extension study for continuing to use them beyond the 2023 book lives of these units;
- The Department’s analysis indicates that retiring Sherco units in 2015-2017 time frame will impose significant cost increases ranging from $0.7 to 2.6 billion;
• Conducting a baseload diversification study now will needlessly add administrative burden for Xcel and intervening parties.

Should the Commission order a baseload study, MCC recommends the focus should be focused on evaluating the retirement of Black Dog units 3 and 4, not Sherco 1 and 2. Xcel’s resource plan retires Black Dog 3 and 4 in 2015, and MCC believes further analysis needs to be made before making this decision.

MCC agrees that compliance with the EPA MATS rule is an issue, but believes Xcel has yet to evaluate (or at least propose) more cost-effective options to comply with MATS. MCC recommends Xcel evaluate making the “minimal investment for compliance” at Black Dog to keep it as a coal-fired facility until 2020. MCC believes analyses such as running the unit with the current costs of the retrofit being used and lower level of MATS compliance improvements are alternatives not sufficiently addresses at this time.

Environmental Intervenors Reply Comments

Black Dog. The Commission should not require more evaluation of the Black Dog life extension. The EIs do not agree with MCC’s recommendation to continue to operate Black Dog 3 and 4 on coal due to compliance with MATS. In response to MCC’s suggestions for Black Dog alternatives:

“Baseload options only make sense if one assumes Xcel is going to retire the existing baseload a refurbished Black Dog would replace. At page 11, the Chamber notes that the cost estimate for the Sherco upgrade is $1,703 per kW and life extension at Black Dog is $1,600 per kW.”

Assuming the Chamber is not suggesting that retrofitted Black Dog units operating on coal could serve as an alternative to Xcel’s other baseload units such as Sherco 1 and 2, then it makes little sense to compare the cost of upgrading these units to each other. The question is not whether retrofitting Black Dog with pollution controls is cost comparable with or even cheaper than other coal units, but rather whether doing so is least-cost for ratepayers compared to a full range of alternatives. Xcel’s methodology for evaluating this question, using the Strategist model, is appropriate and much better suited to evaluating the least-cost option for Black Dog’s future rather than a simple comparison to other coal units.

Second, with respect to the Chamber’s request for a cost-benefit analysis of temporarily burning natural gas instead of coal, it is not clear what benefit such an analysis would yield. After 2014, absent pollution controls, Black Dog cannot continue to burn coal. 42 U.S.C. § 7412(i)(3)(A) (compliance with MATS required within three years of final regulation). As we understand it, Xcel plans to burn coal until its current stockpile is exhausted and then continue to operate those units on natural gas as needed.1 As a result, there will be a very short window in which natural gas and coal are interchangeable fuels at Black Dog.”

Sherco 1 and 2. The EIs believe DOC’s analysis of retiring Sherco 1 and 2 failed to include the projected costs of refurbishment. DOC did not include the cost of upgrading Sherco Units 1 and 2 in Xcel’s base case. Therefore, the EIs contend that the “Department’s conclusions about Sherco retirement are not supported and, in any case, premature given the level of analysis.”
Solar*Rewards. The EIs point out that the IRP consists of three solar programs, including Solar*Rewards. In both the initial IRP filing and the 2011 Update, Xcel discussed Solar*Rewards as making an important contribution to Xcel’s solar resource portfolio. The Company, however, did not file a Notice of Changed Circumstances when Xcel announced the program would be ended.

The EIs request that the Commission order Xcel to maintain the current Solar*Rewards program while it works with stakeholders to develop a replacement plan. The replacement plan should be filed in its next IRP “to prevent disruption in the Minnesota solar market.”

Demand Response. The EIs continue to urge Xcel to increase its demand response capabilities.

Calpine Corporation Reply Comments

In their reply comments, Calpine Corporation reiterated its request that the Commission accept Xcel’s motion to withdraw its Black Dog certificate of need, close the Black Dog Docket, and enter into Power Purchase Agreement negotiations for the Mankato Expansion for commercial operation in 2017.

Calpine’s recommendation is premised on their argument about the intention of the Black Dog contested case. Calpine notes:

“The Black Dog contested case proceeding was established to determine (a) whether there is a need for new capacity and, if so, (b) which of two specifically proposed projects should be approved to meet that need.”

Calpine disagrees with Xcel’s recommendation in their reply comments to “revise the scope of the Black Dog proceeding.” From Calpine’s view, the Black Dog Repowering Project no longer exists, so there is no reason to revise the scope of the proceeding. The Black Dog docket was not intended to be a generic evaluation of different types and sizes of projects, but instead which two projects, the Black Dog repower or the Mankato Energy Center expansion, were best suited to meet Xcel’s capacity need. Calpine states that “expansion of the Mankato Energy Center is now the only formally proposed project that is on the table.”

Calpine emphasized that delay is not in the interest of ratepayers. Since Xcel made a motion to withdraw the certificate of need for Black Dog, Calpine argues that a future contested case would derive from an entirely new certificate of need application.

Calpine is particularly concerned about why Xcel agreed with DOC’s recommendation to procure 400-600 MW of natural gas capacity, but has yet to detail how to meet that recommendation.

Calpine recommends the Commission require Xcel to enter into negotiations for the Mankato expansion. If appropriate, Calpine recommends the Commission require Xcel to issue a Request for Proposals for additional natural gas supply beyond the Mankato expansion.

35 Xcel reply comments. p. 23.
Prairie Island Indian Community Reply Comments

The Community recommends the IRP be consolidated with the Prairie Island Uprate – Notice of Changed Circumstances proceeding as part of a contested case where these and all of the other, significant issues can be fully explored and resolved.

On August 7, 2012, the Nuclear Regulatory Commission (NRC) issued a Memorandum and Order which suspended issuing final decisions on new licenses and on license renewals for nuclear power plants until NRC decides how to deal with spent nuclear fuel. Memorandum and Order, CLI 12-16.

In a New York v. NRC ruling in June 2012, the U.S. Court of Appeals for the District of Columbia Circuit struck down the NRC’s “waste confidence” provisions, ruling the NRC violated the National Environmental Policy Act (NEPA) in issuing its 2010 update to the Waste Confidence Decision and accompanying Temporary Storage Rule.

According to the Community, the resolution of the temporary nuclear waste storage issue will add greater delays on the licensing amendment proceedings than previously projected by either Xcel or the Department.

Response to the Department

First, the Community believes that Xcel’s downward adjustment to its demand forecast is appropriate. Second, the Community disagrees with DOC’s recommendation to use the median forecast instead of the recession-adjusted forecast. Third, the Community argues the Department’s concern regarding Xcel’s forecast is speculative.
Staff Analysis

Staff has identified the following issues in the Xcel resource plan:

- From Staff’s perspective, the most significant issues are whether Xcel’s IRP, particularly the five-year action plan, has sufficiently demonstrated the Company’s need, and whether the proposal to meet that need has enough clarity. Xcel filed its resource plan in August 2010, and the Company’s action plan has changed significantly since that time.

- Of particular note, Xcel’s 2011 Update lowered its demand growth to 0.5 percent and energy growth to 0.9 percent. Based on this downward revision, Xcel does not expect a capacity deficit until 2016. However, the Prairie Island Uprate (117 MW) currently exists in Xcel’s five-year action plan, but, Xcel appears to be undecided as to whether, or when, to pursue the uprate. From Staff’s understanding, there does not appear to be clear backup plan in the event demand grows higher than 0.5 percent and the Prairie Island uprate will be further delayed, or canceled.

- The Commission could approve or accept the resource plan for planning purposes overall, but make a finding that the Company’s five-year action plan does not sufficiently address its resource need. If the level of uncertainty is too great, the Commission could reject the plan and accelerate the filing of the next plan.

- There is seemingly consensus that Xcel will need to add several hundred megawatts of resources by 2017, even with the Prairie Island uprate. Xcel agrees with DOC’s analysis which suggests the Company should add 400-600 MW of natural gas capacity in the 2017-2019 timeframe. Xcel is requesting the Commission revise the scope of the Black Dog Repowering Proceeding to identify the best plan to meet the 400-600 MW resource need. Calpine argues the Mankato Energy Center is the best alternative to the Black Dog proposal, which Xcel has withdrawn.

- With the new EPA rules, Xcel does not believe it is economically feasible to retrofit Black Dog 3 and 4 with pollution controls. Once Xcel retires Black Dog 3 and 4, Sherco 1 and 2 will represent more than 50 percent of its remaining coal-fired capacity. Xcel expects to install mercury and fine particulate matter controls at the Sherco units, and the Company is uncertain at this time regarding whether or not additional NOx controls will be required. Xcel expects more detail to emerge from a “Life Cycle Management Study” the Company is conducting for Sherco 1 and 2. The Commission may wish to ask Xcel whether a decision not to add NOx controls would suggest anything about a retirement date for Sherco 1 and 2.

- The Environmental Intervenors recommended a baseload diversification study be ordered requiring Xcel to evaluate retiring Sherco 1 and 2 by 2017. The EIs recommend the Commission approve the IRP, but the approval should be conditioned on the Sherco baseload study. The Commission could determine whether a baseload study is needed for Sherco 1 and 2, and if so, decide whether to incorporate it as a stand-alone study to be filed sooner than, or as part of, Xcel’s next resource plan filing. The Commission may wish to ask Xcel and the EIs how the recommended baseload diversification study and Xcel’s Life Cycle Management Study would be different, and how they would be similar.
• Xcel announced a decision to phase out Solar*Rewards in 2013. In October 2012, the Department of Commerce Deputy Commissioner issued a decision requiring Xcel to keep Solar*Rewards through 2015, but the rebate was reduced. Several intervenors recommended Xcel expand not just its solar generation, but other forms of distributed generation. Xcel stated its willingness to work with stakeholders at the direction of the Commission regarding distributed generation. Presumably, the outcome of this work would include a more robust analysis of distributed generation in Xcel’s next resource plan.

• In the Company’s initial filing, Xcel’s base case priced CO₂ at the midpoint of the Commission’s approved range. In its 2011 Update, Xcel removed CO₂ from its base case. To be consistent with previous resource plan orders and DOC’s modeling approach, the Commission could direct Xcel to put CO₂ back into the base case for its next resource plan.

1. Xcel’s resource plan has been significantly modified since their initial filing

Xcel’s resource plan was filed in August 2010. The Company filed an Update to the Resource Plan in December 2011. Xcel states in the 2011 Update that “much of our proposed Five-Year Action Plan remains unchanged.” However, Staff considers the 2011 Update to be, in essence, an entirely new resource plan, particularly with respect to the five-year action plan.

First of all, the underlying basis upon which Xcel developed its 15-year plan was changed. Xcel states on page 3 of its 2011 Update, “the most important information is fundamental data regarding the status of the economy and projections of economic growth.” Then, Xcel goes on to say on page 14 of its Update that “unexpected setbacks to the country’s economic recovery and more significant wholesale municipal customer attrition have substantially changed our expectations for future resource needs.”

This revised economic outlook, including a reduction to 0.5 percent demand growth, was a major driver of the Black Dog Repowering Project being removed from the five-year plan. There is also an increasing level of uncertainty about the Prairie Island uprate. Regarding Prairie Island, Xcel states that “there are areas where the record regarding prospective risks could be further developed,” and Xcel suggests a stakeholder conference “to discuss the prospective analysis and risks assessment to further develop the record.”

2. Xcel’s reply comments discuss circumstances which have changed Xcel’s planning approach even further beyond the 2011 Update.

Xcel states in their reply comments that the Company’s “current need assessment has not changed significantly from the Update.” Xcel provides an Updated Need Assessment (i.e., the 2011 Update was revised) on page 9 of their reply comments (full table in Attachment A):

36 Xcel’s July 20, 2012 reply comments in Docket No. 08-509, p. 3.
The above table, provided in Xcel’s reply comments, shows a difference of about 300 MW less surplus capacity in 2015 than in Xcel 2011 Update.

The same table also provides a Need Uncertainty Range. According to Xcel, “between 2017 and 2019, the expected need could range anywhere from zero to 562 MW.”

It is important to note that the Need Assessment assumes the 117 MW capacity increase from the Prairie Island. However, by Xcel’s own admission, the benefits are “diminishing,” and those benefits which would occur do not exist until “later in the life of the project.” As shown below, Xcel does not expect a negative Present Value Revenue Requirement for the Prairie Island uprate until 2027.37

The amount of capacity which is “feasibly capable” of being increased at Prairie Island is the same as the 2015 surplus Xcel projects in the Updated Need table shown above (in red parentheses) and in Xcel’s August 2012 reply comments (117 MW).

37 Xcel’s July 20, 2012 reply comments in Docket No. 08-509, p. 3.
Thus, regardless of whether the changes from the initial filing to the 2011 Update, or from the 2011 Update to the reply comments are qualified as “major” or “minor,” “significant” or “small,” the trend seems to be that expectations are constantly changing, and Xcel’s expectations fall under an enormous cloud of uncertainty.

Since much of this uncertainty falls within the five-year plan, Staff agrees with XLI that “the five-year plan is ambiguous.” XLI cites Minn. Rules 7843.0400 subp. 3, which states that the five-year plan “must include a schedule of key activities, including construction and regulatory filings.”

In review of Xcel’s previous resource plan (the 2008-2022 IRP), it seems that a similar trend that transpired then is transpiring now. In December 2007, Xcel filed its 2008-2022 resource plan. In September 2008, Xcel filed an updated resource plan, citing changes in higher fuel and construction costs and slowing economic indicators as reasons for the update. Xcel filed a modified 5-year action plan in February 2009 to defer both a peaking facility in 2011 and the previously proposed expansion at Sherco Units 1 and 2. Xcel then requested the Commission close the 2007 resource plan docket and file the Company’s next resource plan in August 2010.

Staff understands that, since August 2010, Xcel has been presented with new types of changes beyond their control, such as EPA regulations, an uncertain economy, and the Fukushima Daiichi nuclear disaster. However, the Commission may be uncomfortable approving Xcel’s plan given the uncertainty in its five-year action plan, but, at the same, not want to reject the plan in light of changing circumstances.

If the Commission determines the record is sufficiently robust for planning purposes, the Commission could approve the plan. Obviously, the answer to the question of what will happen in the future never can be absolutely correct, and Xcel has, from Staff’s view, provided: an appropriate wind procurement strategy, a reasonable strategy so far to comply with EPA rules, and a DSM level consistent with the Department’s recommendations. Moreover, Xcel has adopted DOC’s and Calpine’s recommendations of the procurement of 400-600 MW of natural gas by 2019.

Still, significant questions remain about Xcel’s five-year action plan. If the Commission determines the record is incomplete, the Commission could then decide how to proceed to get to an adequate record. For example, rate impacts, socioeconomic impacts, and policy uncertainty—specifically EPA rules—are areas of common concern among parties. Therefore, the Commission could contemplate ways in which further information, either through a baseload study or a new resource plan, could contribute to an adequate record.

3. **Department’s recommendation of 2015-2016 market purchases**

As shown in the Updated Need Assessment tables above and on page 48, Xcel projects a surplus capacity of 117 MW in 2015. This number assumes the Prairie Island uprate. Based on the Need Uncertainty Range, in 2016, Xcel projects an error bound of 140 MW of surplus in the low forecast, or a 135 MW of deficit in the high forecast.

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38 XLI comments, p. 2
To provide a cost-effective bridge to the Company’s next capacity expansion (400-600 MW of natural
gas in 2017-2019), the Department recommends Xcel to “use short-term purchases to fill any capacity
needs in 2015-2016.” If the Commission needs more clarity on this issue, the Commission could ask the
Department at oral argument to clarify this recommendation regarding how exactly DOC expects Xcel to
utilize the market, or in what form (for example, a wholesale bilateral contract).

The Commission could also ask Xcel whether it is the Company’s intention to use the market, and if so,
how and how much. Xcel’s reply comments indicate that “if capacity is needed in 2015, Xcel considers
participation in MISO’s capacity market as a more economic option [than the Black Dog Repowering
Project] to provide a ‘capacity bridge.’” The problem with Xcel’s statement is that it presumes the
capacity will be there when Xcel needs it, and the details are vague with respect to securing this
wholesale capacity.

Staff does not doubt that excess capacity will exist, but notes that the Commission may direct Xcel to
notify the Commission exactly when the Company will make a decision to rely on the market instead of
some other option.

Intervening parties presented several alternatives to the market:

- The Chamber proposed “minimally complying” with the MATS rule until 2020, such that Black
  Dog 3 and 4 could remain in operation;
- Several solar manufacturers and the EIs discussed the success of Solar*Rewards and the
  relatively high abundance of solar insolation, which provide another resource option which the
  Company could pursue; and
- The EIs and the Chamber, among other parties, recommended that Xcel develop a more robust
demand response portfolio.

The Department also recommended Xcel procure 100-200 MW of wind in 2015-2016. MISO’s 2012-
2013 Loss-of-Load-Expectation (LOLE) Study Report set the footprint’s wind accreditation at about 15
percent. This assumed accreditation would translate into about 15-30 MW of capacity on Xcel’s system.
In considering the market capacity purchases and the intervening parties’ recommendations, the
Commission may wish to ask the Department whether their wind recommendation is to fulfill a capacity
need or an energy need.


Even with Xcel’s downward-shifted forecast, the Company projects (assuming the Prairie Island uprate
moved forward) a capacity deficit of:

- 121 MW in 2017;
- 319 MW in 2018; and
- 452 MW in 2019

DOC and Calpine support a finding from the Commission which requires Xcel to procure 400-600 MW of
natural gas capacity in 2017-2018, with at least half of which should be combined cycle. However, DOC
recommends the Commission reject Xcel’s motion to withdraw the Black Dog certificate of need
petition, while Calpine recommends the Commission accepts the motion to withdraw.
In their reply comments, Xcel agrees with the natural gas procurement recommendation with two modifications. First, Xcel suggests extending the timeframe by a year, such that the recommendation would apply from 2017 through 2019.

Second, Xcel believes it is premature to distinguish between types of natural gas facilities. Xcel states that the type of capacity, combined cycle or combustion turbine, would be better decided in the competitive acquisition process. Xcel believes that the resource acquisition process would examine of actual proposals to meet the identified resource need. Furthermore, more informed decisions can then be made based on actual proposals as opposed to assumptions.

The Department argues that its recommendation that at least half of the natural gas capacity be combined cycle is based on its analysis that such a requirement would minimize Xcel’s PVRR. Due to the uncertainty of baseload capacity resources among other factors, DOC’s modeling found that a combined cycle unit compromising at least half of the natural gas resource continually appears as the appropriate option. Xcel notes the size and timing of the Company’s next resource additions will be a focus of their next resource plan.

Several intervenor recommendations are made regarding this 2017-2019 timeframe:

- **DOC**: Procure 400-600 MW natural gas capacity in 2017-2018, at least half of the natural gas capacity should be combined cycle (Xcel agrees with the size, but recommends the Commission take no position on the type);
- **Calpine**: Agrees with DOC’s assessment of size, type, and timing, but recommends the Commission require Xcel to enter into a PPA with Calpine for a 345 MW natural gas expansion at the Mankato Energy Center;
- **EIs**: Approval of the resource plan should be conditioned on a baseload diversification study which further evaluates retiring Sherco 1 and 2 by 2017.
- **MCC**: Black Dog should continue to run on coal, and Xcel should consider continuing operation of the facility depending on further analysis. Also, more analysis is needed regarding Xcel’s MATS compliance.

Staff believes that the 2017-2019 timeframe is reasonable target for purposes of the resource plan docket. Both parties, Xcel and the Department, who have analyzed the forecasts agree that this timeframe is reasonable; therefore, staff recommends using the 2017-2019 timeframe for acquisition of natural gas resources on Xcel’s system.

There is disagreement among the parties regarding what amount of the 400 to 600 MW of natural gas capacity should be combustion turbine peaking units or combined cycle units. Staff believes the Department provided specific reasoning regarding their analysis and the factors that led to their recommendation of “at least half of the natural gas capacity should be combined cycle.” Staff does not entirely agree with Xcel that the type of capacity, combined cycle or combustion turbine, would be better decided in the competitive acquisition process. Delaying that decision would put Calpine at a disadvantage in the Black Dog resource acquisition process by not providing it with complete information prior to submitting a bid.

The Commission could adopt the Department position that a decision be made in the resource plan docket regarding whether Xcel’s natural gas capacity should include, at minimum, half combined cycle. The Commission could also make a generic finding about the size and timing of the resource addition, but not the type of natural gas facility. Or, the Commission could extend the resource plan docket to
require Xcel to make a firm commitment to the optimal mix of combine cycle versus combustion turbine units for the 400-600 MW within a time deemed appropriate to the Commission.

Staff notes that extending the resource plan docket to make a firm commitment to a specific type of natural gas would impose additional delay on the Black Dog CN proceeding.

5. Staff Comment on EPA Rules

The primary driver for EPA-related costs in Xcel’s resource plan is the Mercury and Air Toxics Standards (MATS) rule. As specified under the Clean Air Act, all power plants will have three years (until April 2015) to comply with MATS.

A fourth year compliance extension will be “broadly available” to sources that require extra time to install controls and to address any local reliability issues. The rule states that under § 112(i)(3)(B) state permitting authorities have the discretion to use this extension authority to address a range of situations, including “staggering installations for reliability reasons,” to address “source-specific construction, permitting, or labor, procurement or resource challenges,” and to allow “the installation of replacement power at the site.”

The rule also notes that the development of off-site replacement generation, transmission upgrades, and continued operation of a retiring plant while other plants install controls “may provide reasonable justification” for a fourth year extension where necessary.

A fifth year for compliance may be allowed for “reliability critical units.” Under the compliance planning pathway developed by EPA’s Office of Enforcement and Compliance Assurance, utilities will develop compliance plans; engage the relevant grid operator, FERC, and the public utility commission or service commission; analyze any reliability risk with the relevant grid authority; and apply for “expeditious extensions” under § 113(a) where necessary.

Staff believes Xcel is sufficiently and appropriately tracking EPA rules, and the Company provides a robust analysis of their impact in the IRP record. However, there is still disagreement among Xcel and the intervenors about what the costs actually will be, and consequently, the most appropriate compliance pathway. Therefore, the Commission may direct Xcel to submit a more narrowed EPA rules
(or MATS rule) analysis in their next resource plan, which contains a specific focus on a particular unit or units.

6. Solar Resources / Distributed Generation

Solar Resources

As part of Xcel’s 2010-2012 CIP Triennial Plan, DOC approved Solar*Rewards program under Minn. Stat. § 216B.241, Subdivision 5 (a) allowing utilities to count savings from qualifying solar energy projects toward the 1.5 percent energy savings goal. Solar*Rewards was also approved under Minn. Stat. § 216B.2411, Subdivision 1 allowing utilities to spend up to five percent of the minimum spending requirement on distributed generation, or up to 10 percent on qualifying solar projects with the Commissioner’s permission.

Xcel’s initial IRP filing included a projection to grow its solar resource portfolio to about 20 MW by 2020. By the time of the Company’s 2011 update, Xcel announced its solar generation had increased from 1 MW to over 4 MW. From Xcel’s 2011 Update:

“At the time we filed our Resource Plan, we had just over 1 MW of solar generation on our system. By the end of 2011, we may have up to 4.2 MW of solar capacity on our system. Close to 3 MW of this amount is capacity added under our Solar*Rewards program. Since the launch of this program nearly two years ago, customers’ interest in installing solar on their homes and businesses has been strong enough to allow the program to reach its statutory spending limit for 2011, and be on track to reach it again in 2012. Over 30 percent of the capacity installed under this program is from panels manufactured in Minnesota.”

On June 1, 2012, Xcel filed its proposed CIP Triennial plan for 2013-2015, which included a proposal to phase out of the program by the end of 2013. Xcel’s decision was also explained in the Company’s reply comments:

“Our decision to phase out Solar*Rewards from CIP by the end of 2013 was based on several factors, including the high cost of solar compared to other resources; rebate levels and cost-effectiveness results that are out of line with other CIP programs; and lack of an effective regulatory framework.”

Regarding Solar*Rewards, the Department states on Page 31 of its comments in Xcel’s CIP docket:39

“Xcel’s proposal to discontinue Solar*Rewards is inconsistent with the Department and Xcel’s determination that Xcel will need additional resources in the future as well as the utility’s own assessment that customer-sited solar and other distributed generation sources will be an important part of its portfolio. Staff conclude that discontinuing Solar*Rewards is inconsistent with Xcel’s stated commitment to include solar as part of its portfolio and to advance the solar industry in Minnesota.”

39 Docket No. E,G002/CIP-12-447
On October 1, 2012, the Commerce Commissioner issued a decision requiring Xcel to continue Solar*Rewards in 2013, 2014, and 2015 with the same budget ($5,000,000) as the 2010-2012 triennial, but with the reduced incentive level of $1.50/watt.  

The EIs initially recommended that Xcel develop a solar resource study, but that recommendation was withdrawn in the EIs’ reply comments. (Xcel objected to developing a solar resource study.) In its place, the EIs requested the Commission order Xcel to work with stakeholders to develop a replacement plan for Solar*Rewards.

Distributed Generation in Resource Planning

While Xcel disagreed with developing a solar resource study, the Company did indicate in its reply “to continue to evaluate solar as part of a broader distributed generation effort.” This “broader distributed generation effort” was identified by several intervenors as a limitation in Xcel’s instant resource plan.

The University of Minnesota cited “18 operating dry-grind ethanol plants in Minnesota capable of producing up to 600 MW of electricity.” The Chamber recommended the Commission order Xcel to examine suitable sites in Minnesota for combined heat and power. Solar manufacturers filed comments encouraging the Commission to require Xcel to extend Solar*Rewards and realize more of Minnesota’s solar resource potential.

Xcel’s IRP included a goal to increase its solar resource to 20 MW in a decade, and the Company also expressed a willingness to work with stakeholders “regarding the design of an appropriate regulatory structure that addresses the value of distributed generation.”

The Commission could request clarification from Xcel regarding whether the Company still has the 20 MW solar goal. The Commission could also adopt the recommendation the EIs withdrew, and require Xcel to develop a solar resource plan. It is seemingly Xcel’s intent to move its solar resource procurement outside of CIP, eventually end the Solar*Rewards programs, and re-evaluate how solar fits into its resource portfolio.

Staff agrees with the intervenors that fitting a more robust distributed generation study, including but not limited to solar, into resource planning would be a valuable contribution to the next IRP record.

7. Baseload Diversification Study / Deadline for the Next Resource Plan

The EIs recommend a baseload diversification study on Sherco 1 and 2 be filed within six months of the Commission order. Xcel proposed July 1, 2013 as a filing date. MCC recommends a baseload study continuing coal-fired operation of Black Dog 3 and 4 beyond 2015.

Developing a baseload study focused on a specific plant is useful because it adds a level of specificity and detail to the costs and benefits of operation which may not exist in resource plans. However,

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40 Commerce Commissioner Decision #9, Docket No. E,G002/CIP-12-447.
41 University of Minnesota comments, p. 5
42 Xcel reply comments, p. 17
looking at one or two plants in isolation would not have the systems perspective of a full IRP. If the Commission determines that enough urgency exists in the decision-making process to retire Sherco 1 and 2 in the short-term, or continue to operate Black Dog 3 and 4 on coal, then a baseload diversification study could be a useful exercise. However, it is not entirely clear how the EIs’ proposed Sherco baseload study and Xcel’s Life Cycle Management Study would be different, or the same. Staff suggests combining these two recommendations into a single study, to be filed sooner than the next resource plan, or in conjunction with the next resource plan.

If the Commission takes the Department’s position that Sherco 1 and 2 are “highly cost-effective” to operate in the near-term, then the Commission may decide not to require Xcel to conduct a baseload diversification study.

Given the level of uncertainty in Xcel’s resource plan, including the future of Sherco 1 and 2, it would be useful to set a deadline for the next resource plan which is as soon as practicable. Staff suggests July 1, 2013 to coincide with Xcel’s Sherco Life Cycle Management Study, but the Commission may ask parties what is a reasonable timeframe.

8. CO₂ Emissions

As shown in Figure 9.2., Xcel’s initial filing projected system CO₂ emissions to reduce by about 20 percent below 2005 by 2015, and nearly 25 percent below 2005 levels by 2020:

Xcel attributes the sharp reduction in CO₂ emissions from 2005-2010 to the MERP projects and increased levels of renewable energy.

According to the Department’s base case modeling, Xcel’s CO₂ emissions are projected to increase by 21 percent during the planning period:
DOC’s base case includes a $21.50/ton value for CO₂. Xcel’s initial filing modeled CO₂ at $17/ton starting in 2012 and escalating at 1.9 percent per annum. (Xcel’s $17 value was, at that time, the mid-point of the initial PUC-approved range of $4 to $30.) Xcel eliminated CO₂ prices from the base case in the Company’s 2011 Update.

On June 3, 2011, the Commission issued an Order Establishing 2011 Estimate of Future Carbon Dioxide Regulation Costs maintaining the estimate of the range of likely costs of CO₂ regulation at between $9 and $34/ton of CO₂ emitted in 2012 and thereafter. ⁴³ In previous resource plans for investor-owned utilities, the Commission has ordered Minnesota Power, ⁴⁴ Otter Tail Power, ⁴⁵ and Interstate Power & Light ⁴⁶ to include CO₂ in their base case for planning purposes.

Inclusion of CO₂ in the base case has the dual purpose of statutory compliance and providing a level of consistency with the Department’s modeling. The Department’s reply comments re-ran its Strategist model without CO₂ costs included, and the results did not change DOC’s recommendations. Nevertheless, the Commission could require Xcel to include CO₂ in the base case of its next resource plan.

Xcel does not clearly explain the Company’s reasoning for excluding CO₂ from the baseline assumptions. Staff speculates that the reason may have been due to the decreased likelihood of carbon regulation at the federal level. However, previous Commission orders requiring CO₂ regulation have been based on compliance with existing Minnesota statutes, not probabilities of near-term federal tax policy. It should be noted that resource plans are a planning tool, and the Commission may consider CO₂ prices in resource planning differently than another proceeding, such as a certificate of need.

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⁴⁴ Docket No. 09-1088
⁴⁵ Docket No. 10-623
⁴⁶ Docket No. 08-673
9. Public Policy Rate Impacts

MCC recommended that Xcel include a rate impact analysis of public policy mandates, such as the Minnesota RES.

Pursuant to Minn. Stat. § 216B.1691, subd. 2e, Xcel filed its Renewable Energy Rate Impact report in Docket No. E-999/CI-11-852. Some conclusions of the report included:

- During the 2008/2009 time frame, energy prices were about 0.7 percent lower with the wind resources that were part of Xcel’s system than prices would have been without them.
- Xcel projects that customers will pay approximately 1.4 percent more for energy over the next 15 years as the result of complying with the RES.
- While the results show renewables to be slightly more expensive over the planning period, the differences do not appear significant.

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According to Xcel’s analysis, the rate impacts of the RES range from -0.24 percent lower (tax credit extended) to 1.82 percent higher (base case analysis) than the No RES Case in various years of the planning period. Xcel states that, “with the exception of certain mandated resources, the renewable based resources that we have acquired to date have been cost effective.”

Staff notes that under the renewable energy rate impact of standard compliance requirement in 216B.1691, “a report must be updated and submitted as part of each integrated resource plan or plan modification filed by the electric utility.” Thus, Staff’s understanding is that Xcel is already required by statute to comply with the Chamber’s recommendation on policy rate impacts.

47 Assuming the federal wind production tax credit expires in 2013 and natural gas costs remain low
10. Scope of the Resource Plan

Resource planning is inherently a long-term view of a dynamic world. XLI qualified resource planning as “a lengthy and convoluted process” and that “the present system simply does not work.” While it is not to say that the process cannot be improved, the development of this record has provided significant stakeholder involvement, and has included transparency into Xcel’s operating plans.

Since the 2007 resource plan, there have been a great deal of policy changes and economic volatility. During this time, Xcel has annually filed information in resource planning dockets describing, in detail, the intent of its operations, whether through an IRP, update, or changed circumstances filing.

Therefore, Staff does not agree that the solution to the limitations of Xcel’s IRP is to scrap the resource planning process altogether. Staff’s view is that it would be a better solution to provide constructive direction to Xcel regarding the content, value, and level of detail of the Company’s filings, especially the five-year action plans.

It is also important to note the scope of resource plans. By statute, resource plans constitute *prima facie* evidence under Minn. Rules 7843.0600, Subp. 2, and a decision from the Commission in a resource planning docket may or may not be enforced in later proceedings, such as a rate case.

As such, Calpine’s recommendation to order Xcel to enter into a specific PPA for the Mankato Energy Center expansion may be outside the scope of resource planning, which intends to “identify that set of resource options as a preferred resource plan.” It is more appropriate for resource plans to identify the size, type, and timing of a set of resources within a 15-year planning period, not generally to require specific PPAs.

Minn. Rules 7843.0400, Subp 2 states that a “utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing.” Since Xcel was not committed to the Mankato Energy Center expansion at the time of the IRP filing, Staff’s understanding is that the Commission need not require the PPA.

In addition, Minn. Rules 7843.0400, Subp. 4 states that “a utility shall include in its resource plan filing the likely effect of plan implementation on electric rates and bills.” Both Xcel and DOC identify Present Value Revenue Requirement as the most appropriate metric to evaluate the least-cost nature of resource planning. Since Minnesota’s resource planning rules require Xcel to identify resource additions generally, and costs from how Xcel procures those resources can be recovered a number of ways, a definitive rate impact analysis as recommended by XLI and MCC may be difficult for Xcel to accurately demonstrate, particularly with respect to customer class allocation.

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48 Minn. Rules 7843.0500, Subp. 2.
Decision Options

Resource Plan Approval

1. Approve Xcel Energy’s 2011-2025 resource plan. This finding of approval does not extend to particular generation projects that are currently under review in other proceedings or will be subject to review under future proceedings, but is a general finding that the plans filed by Xcel appear to be reasonable.
   a. Coordinate with the Department to resolve forecasting issues prior to the submission of any certificate of need or rate case filing (DOC recommendation);

2. Accept Xcel Energy's 2011-2025 resource plan, noting that, given the record presented to the Commission at present, Xcel’s proposed five-year action plan does not sufficiently address the Company’s potential resource need.


Compliance Filings

4. Find that Xcel’s rate impact analysis provided in the Company’s resource plan and reply comments are insufficient, and require Xcel to file an updated rate impact analysis as soon as practicable (XLI, Chamber recommendation)

5. Require Xcel to file a “fuel acquisition and risk management plan” as soon as practicable (Chamber recommendation)

Natural Gas Procurement / Black Dog 3 and 4

6. Require Xcel to procure 400 to 600 MW of natural gas capacity in the 2017 to 2019 timeframe;
   a. Make a finding that at least half of the natural gas capacity should be combined cycle (DOC recommendation)

7. Require Xcel to issue a Request for Proposals for a 20-year fixed price gas contract (Chamber recommendation)

8. Find that operating Black Dog Units 3 and 4 in their existing form is not least cost beyond 2015 (Xcel recommendation)
Prairie Island Uprate

9. Require Xcel to continue to pursue the uprate at Prairie Island (DOC recommendation);

10. Take no action on the Prairie Island uprate within the resource plan proceeding, and adopt and incorporate the Commission actions in Docket No. E-002/CN-08-509 into Xcel’s next resource plan.

Solar*Rewards

11. Require Xcel to work with stakeholders to modify or replace the Solar*Rewards program with a plan that will ensure continued and increasing levels of investment in solar (Environmental Intervenors recommendation)

12. Order Xcel to maintain the current Solar*Rewards program while it works with stakeholders to develop a replacement plan (Environmental Intervenors recommendation)

   a. Order Xcel to file the replacement plan in its next IRP

Baseload Diversification Study / Life Cycle Management Study

13. Require Xcel to submit a baseload diversification study by July 1, 2013, as part of the Company’s next resource plan, that examines the feasibility and cost-effectiveness of:

   a. continuing to operate Sherco Units 1 and 2 (Els recommendation); and/or

   b. retrofitting, retiring, or continuing to operate Black Dog 3 and 4 (MCC recommendation)

Requirements for Next Resource Plan

14. Require Xcel to file its next resource plan by July 1, 2013; or

   a. Some other date; and

   b. If Xcel’s resource plan deadline is later than July 1, 2013, Xcel is required to file an update of specifically how the Company expects to meet any projected capacity deficits in 2015-2016. This update is to be filed no later than July 1, 2013.

15. Continue to work with interested parties to identify useful measures of rate impacts associated with the Company’s resource plans and incorporate them into the next resource plan filing (Xcel recommendation);

16. Require Xcel to include some value of CO₂ which is within the Commission-approved range in the base case for planning purposes
17. Require Xcel to include higher levels of demand response capability in its next resource plan (Environmental Intervenors, Chamber recommendation)

18. Require Xcel to reassess acquiring new wind generation for the 2015 to 2016 timeframe, and incorporate a wind assessment in the next resource plan (Xcel recommendation);

19. Require Xcel to include a comprehensive section of all EPA rules which may affect the Company’s operations in the next resource plan.

20. Require Xcel to include higher levels of distributed generation, particularly combined heat and power, in its next resource plan (Chamber recommendation)
Attachment A. Xcel Proposed Resource Needs as of the Company’s August 2012 Reply Comments

Xcel’s analysis suggests the potential for a capacity deficit in the range of roughly 120 to 450 MW in the 2017-19 timeframe and potentially growing to over 550 MW in 2019.

The data illustrates that between 2017 and 2019 the expected need could range anywhere from zero to 562 MW.