APPENDIX A: RESOURCE PLANNING ANALYSIS

Minnesota Power has studied many options for meeting environmental regulations on Boswell Energy Center Unit 4 ("BEC4") and its other units including those for mercury ("Hg"), oxides of nitrogen ("NO_x"), sulfur dioxide ("SO_2") and particulate matter ("PM"). Most recently as part of the analysis completed for the Baseload Diversification Study (Docket No. E015/RP-09-1088) Minnesota Power identified that adding environmental equipment to BEC4 to address mercury and other air toxics indicated that an investment into BEC4 would provide economic benefit for customers over the alternatives of retirement and replacement with other power supply resources. The analysis described in this Appendix will confirm how BEC4 is needed for serving Minnesota Power customers over the long term and how the BEC4 Environmental Retrofit Project ("BEC4 Project") is the most reasonable and least-cost supply option for customers to meet the upcoming compliance requirements for the Mercury and Air Toxics Standard ("MATS") and Minnesota's Mercury Emission Reduction Act ("MERA") regulations.

A. The BEC4 Project is Needed

Minnesota Power's long-term outlook for energy and capacity needs supports Minnesota Power's decision to move forward with the BEC4 Project and to continue operating BEC4. Minnesota Power is projecting growth in both energy and demand over the next decade. Combining the projected growth with a unique mix of energy intensive customers, representing more than 50 percent of regulated sales, rely heavily on energy supply 24 hours a day to ensure their electrical needs are met, Minnesota Power has a high requirement for energy. The growing need for energy produces and maintains one of the highest utility load factors in the nation, an important consideration when evaluating alternatives to the BEC4 Project. Minnesota Power customers gain benefit from resources that are available and generating energy around the clock. Minnesota Power's largely baseload generation fleet, which includes BEC4, was put into place specifically to accommodate its energy intense customer mix and large load factors. BEC4 is and will remain a low cost and reliable generation asset capable of meeting the demands of the system safely and reliably.

1. Forecast for Demand and Energy

Minnesota Power's needs analysis for the BEC4 Plan Petition is based on the Company's available published forecast of demand and energy consumption at the time of this evaluation, which was prepared in June 2012 as part of Minnesota Power's Annual Electric Utility Forecast Report[1] ("AFR") submittal. The AFR contained several long-term scenarios for Minnesota Power's energy and demand requirements. The "Wholesale and Industrial Customer Addition Forecast Scenario," which contains the addition of the Essar taconite pellet facility in Nashwauk, Minnesota,[2] was utilized as the expected outlook for the analysis.

[1] Minnesota Power's Annual Electric Utility Forecast Report is submitted annually by July 1st to the Department of Commerce – Division of Energy Resources ("Department").

[2] Minnesota Power entered into a wholesale customer electric service agreement with the City of Nashwauk in large part to supply a taconite pellet making facility for Essar in the 2014 timeframe.

In order to capture other potential customer expansion in northeast Minnesota out into the 2020 timeframe, the Moderate Industrial Expansion forecast Scenario from the AFR 2012 was considered in the analysis as a high outlook. To gain insight to a lower load outlook, the Low Economical and Industrial Forecast Scenario from the AFR 2012 was considered. Figure 1. Summer Peak Demand Forecast Scenarios Utilized for Plan Petition illustrates the range of demand outlooks utilized in Minnesota Power's BEC4 Plan Petition and identifies Minnesota Power's expectations for customer load requirements for study period (2012-2035).[3]

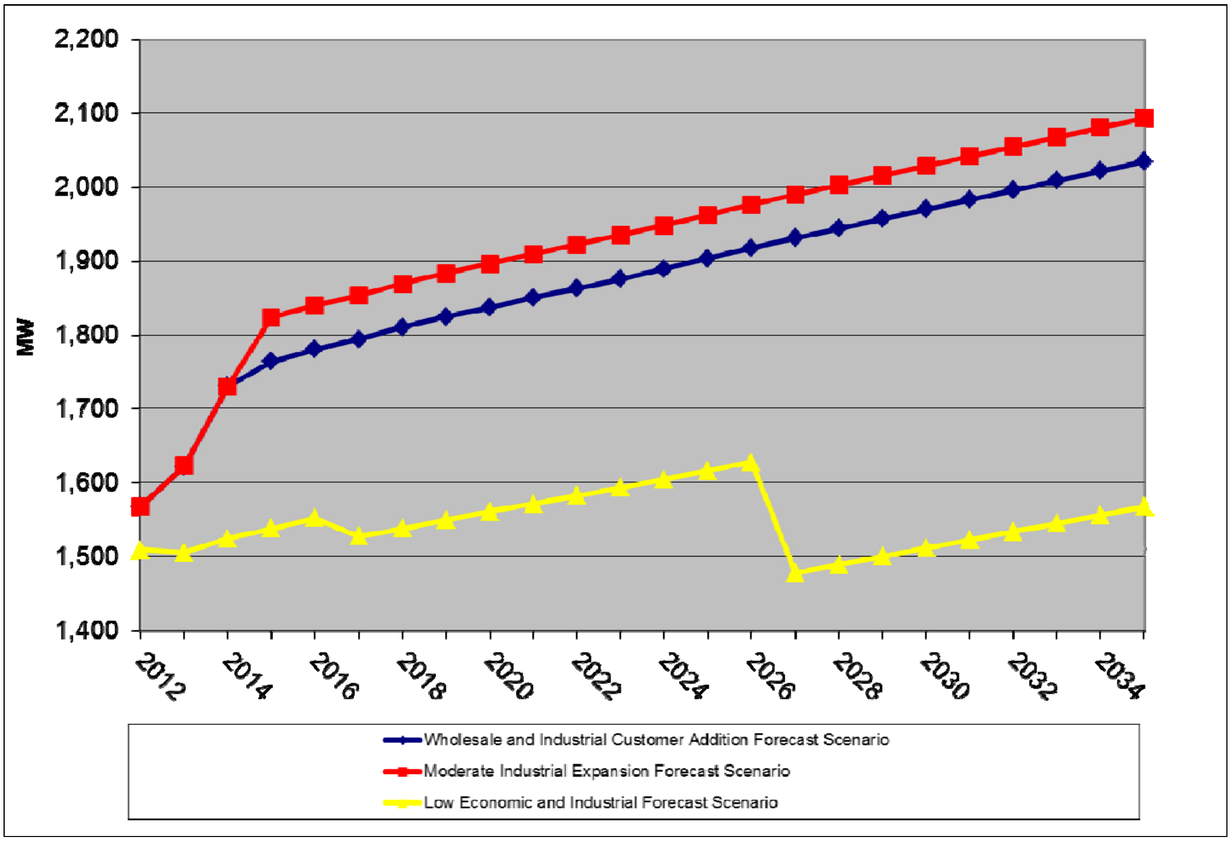

Figure 1. Summer Peak Demand Forecast Scenarios Utilized for Plan Petition

Minnesota Power has seen a dramatic cycle in its load requirements over the past five years. The impact of the 2008-09 economic downturn had significant impact on Minnesota Power's large industrial customer class. This decline was followed by a swift rebound to near-full capability in late 2010. Planned additions by large retail customers and wholesale contract extensions out through 2019 keep Minnesota Power's long-term load growth projections at approximately 1.5 percent in the Wholesale and Industrial Customer Addition Forecast Scenario outlook. This incorporates a projection that Minnesota Power continues to achieve its 1.5 percent energy conservation obligation. Minnesota Power's Wholesale and Industrial Customer Addition Forecast Scenario system load forecast, utilized for this evaluation, has a projected

[3] The econometric demand value for the Wholesale and Industrial Customer Addition Forecast Scenario plus the expected new customer from page 58 of Minnesota Power's 2012 Advanced Forecast Report was utilized as the expected demand outlook for this petition.

(summer) peak demand of 1,837 MW by 2020 and 1,904 MW by 2025 with the more typical 1 percent system growth rate utilized to extend the outlook to 2035.

Energy requirements continue to drive Minnesota Power's supply picture, as its dominant industrial load contributes to the majority of growth being projected. The outlook for energy in the Wholesale and Industrial Customer Addition Forecast Scenario (expected outlook) reaches approximately 13,900GWh by 2020 as shown in Figure 2 Annual Energy Forecast Scenarios Utilized for the BEC4 Plan Petition.

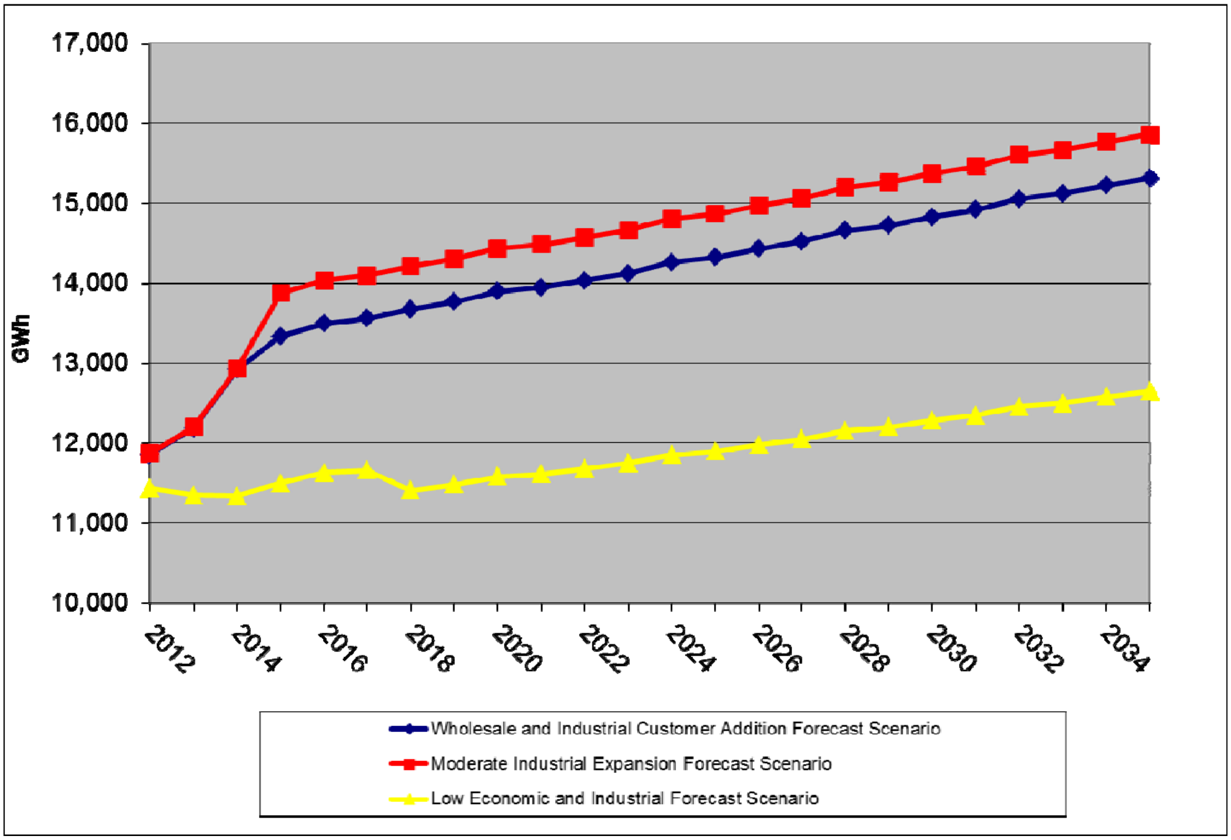

Figure 2. Annual Energy Forecast Scenarios Utilized for the BEC4 Plan Petition

2. Resources Expected to Meet Long-term Requirements

Minnesota Power uses the MISO Module E Load and Capability ("L&C") calculation[4] as one measure to assess future resource need and overall resource adequacy. The MISO L&C calculation takes into consideration Minnesota Power's load forecast, expected demand side resources, firm and participation purchases and sales, accredited generating capability and MISO's required 12 percent planning reserves. The result of the L&C calculation is a capacity surplus (or deficit) projection for each planning season. Minnesota Power is expecting a need for

4 The MISO Resource Adequacy Program identifies how capacity resources are tested to determine their installed capacity values. These values are then utilized to estimate what capacity is available to serve load on an annual basis. Minnesota Power does not utilize the Unforced Capacity (UCAP) method for long term planning as this method does not properly account for long term operational characteristics of generating resources.

capacity in the 2020 timeframe which is when the currently executed 250 MW Manitoba Hydro Power Purchase Agreement is implemented, helping to meet the majority of that need.

Although Minnesota Power is a winter peaking utility, the Company bases its long term planning on its resource needs for the summer season L&C balance since most other regional utilities are summer peaking and, accordingly, have large winter capacity surpluses that are available for Minnesota Power to purchase at moderate prices. The resources identified to meet the summer peak season demand requirements for Minnesota Power customers in the Wholesale and Industrial Customer Addition Forecast Scenario are illustrated in Figure 3. Demand Requirements under the Wholesale and Industrial Customer Addition Forecast Scenario. The important contribution of BEC4 in meeting future demand requirements of Minnesota Power's customers[5] is clearly shown in Figure 3.

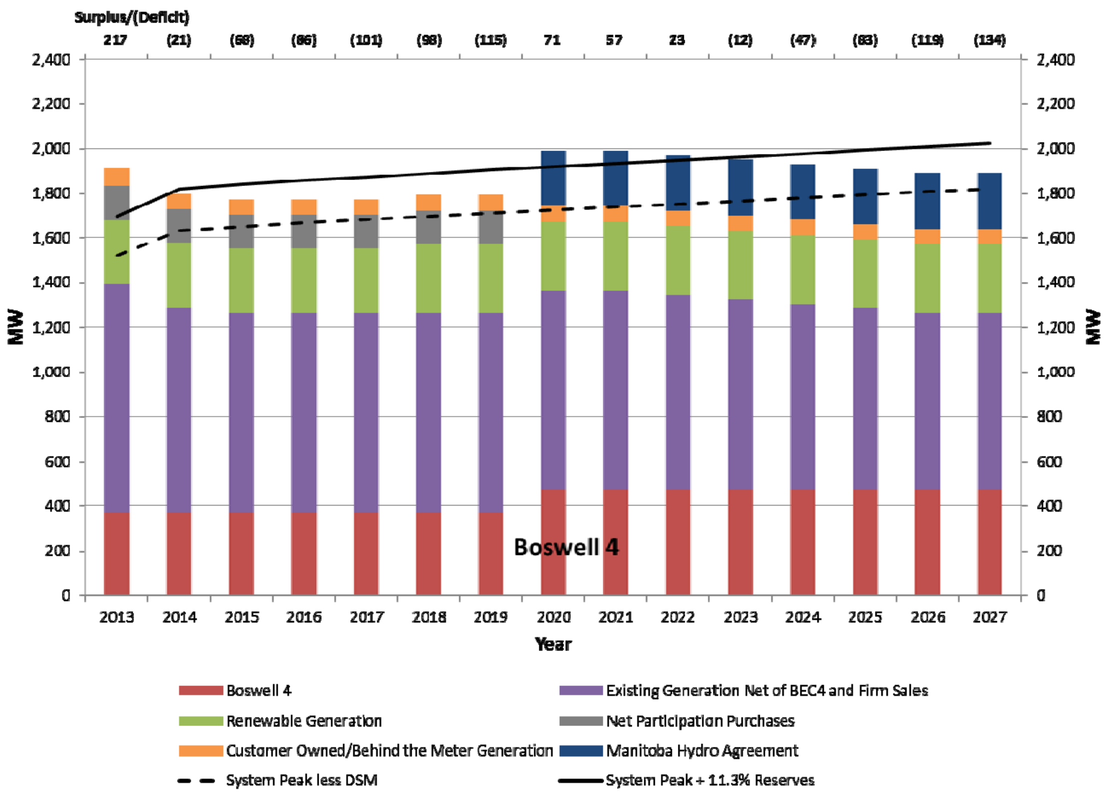

Figure 3. Demand Requirements under the Wholesale and Industrial Customer Addition Forecast Scenario

As outlined in the Company's most recently accepted Integrated Resource Plan (Docket No. E015/RP-09-1088) current company power supply initiatives impacting the projected capacity positions in the long-term outlook scenarios are a) the implementation of Minnesota Power's renewable plan, which incorporates 100 MW of additional wind resources in North Dakota above the current Bison 1, 2 and 3 Wind Projects[6] by 2025, b) the gradual phase-out of

[5] The 100 MW increase in capacity at BEC4 in 2020 is due to the expiration of the 100 MW power sale to Basin Electric Power Cooperative.
[6] The Bison 1 Wind Project was approved through Docket No. E015/M-09-285 and was fully commercially operational in June 2012, the Bison 2 Wind Project was approved through Docket No. E015/M-11-234, and the

227 MW of coal-based generation from Square Butte's Milton R. Young 2 ("Young 2") lignite coal generating station in North Dakota by 2026, c) implementation of 250 MW Manitoba Hydro Power Purchase Agreement in 2020 through 2034, and the utilization of the wholesale market.

As previously discussed, Minnesota Power also has considerable energy needs throughout the study period due to its customer load requirements creating significant load factors on its system. Figure 4. Energy Outlook—Wholesale and Industrial Customer Addition Forecast Scenario is Minnesota Power's energy need outlook, which also shows the critical part BEC4 has in meeting the future energy requirements of customers.

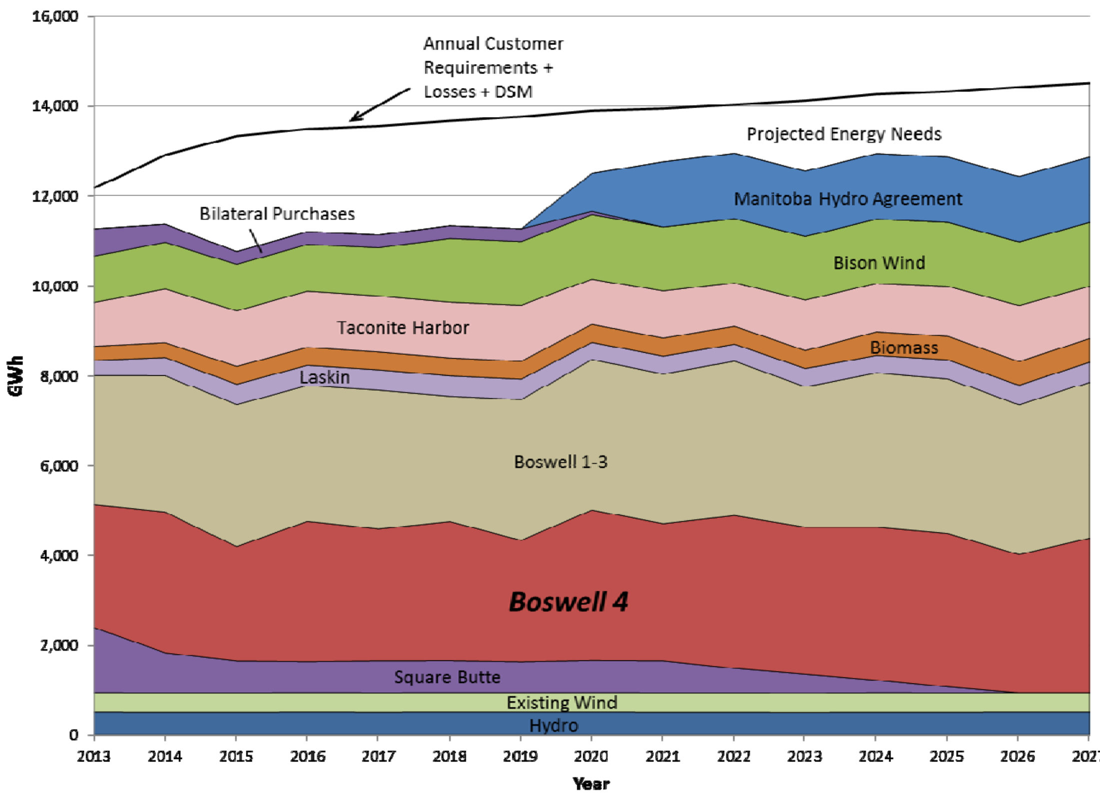

Figure 4. Energy Outlook—Wholesale and Industrial Customer Addition Forecast Scenario

B. Analysis Approach

For the BEC4 Plan Petition, Minnesota Power used planning analysis to quantify the impact and benefit to customers of the BEC4 Project. This section contains an overview of the methods utilized to show that the BEC4 Project is the lowest cost plan when compared to other alternatives and is in the best interest of Minnesota Power customers. For purposes of discussion, the analysis is broken into three parts:

Bison 3 Wind Project was recently approved through Docket No. E015/M-11-626. Both Bison 2 and Bison 3 projects are planned to be operational by the end of 2012.

1. Alternative plans considered for meeting environmental compliance requirements other than the BEC4 Project,
2. Screening of alternative resources to replace BEC4 for customers and
3. Comparative analysis between BEC4 Project and primary replacement alternatives.

Minnesota Power's Baseload Diversification Report provided a rigorous system wide analysis that indicated moving forward with an air emission environmental retrofit on BEC4 would be in the best interest of customers. To ensure that the baseload diversification study results continue to be useful for comparison with the more refined BEC4 Project identified in the BEC4 Plan Petition, it is beneficial to compare the high level air emission environmental capital cost used for BEC4 in the baseload diversification study with what was used for the BEC4 Project. Minnesota Power believes the conclusions from the baseload diversification study can be referenced in the analysis for the BEC4 Project because there is little change in the capital cost used in each scenario and the air emission technology is consistent with that considered for the BEC4 Project. As a component of the three United States Environmental Protection Agency ("EPA") Scenarios analyzed in the baseload diversification study, the capital and operating costs of the Circulating Dry Scrubber ("CDS") technology in all three EPA Scenarios were included in the BEC4 Project analysis. The CDS capital cost assumed in the baseload diversification study scenarios is within three percent of the CDS capital cost used in the analysis for the BEC4 Project. As confirmed by the following analysis, the BEC4 Project is shown to be the lowest cost option for customers over a wide-ranging set of assumptions.

A subsequent filing for cost recovery of investments and expenditures for the BEC4 Project will be submitted to the Commission for consideration and approval at a future date, but not within 60 days of submittal of the BEC4 Plan Petition (see Minn. Stat. § 216B.1692). Integral to the BEC4 mercury emission reduction project, Minnesota Power will ask for cost recovery of a byproduct ash handling system ("ash system") that poises Minnesota Power to meet future regulations on coal ash. Minnesota Power did include capital cost for ash systems to meet different levels of regulations in the three EPA Scenarios used in the baseload diversification study. The capital cost for the ash system used in the BEC4 Project analysis represents a share of the ash system capital cost used in the Stringent and More Stringent EPA Scenario from the baseload diversification study.

1. Alternatives Considered for the BEC4 Project

Minnesota Power considered three alternative paths for meeting capacity and energy obligations represented by BEC4's current production capabilities for this Plan Petition. The three paths considered were:

Path a) Implement environmental retrofit for air emission control at BEC4 in 2016 – the BEC4 Project,

Path b) Delay BEC4 Project with temporary unit shutdown for BEC4 and build a 213 MW combustion turbine natural gas unit in the interim to help with replacement power or

Path c) Shutdown BEC4 in 2016 and replace with a reasonable generation alternative(s).

Each of these alternatives was examined in detail through Minnesota Power's rigorous planning process, which is detailed later in this document.

2. Screening of Alternatives Resources to Replace BEC4

The analysis considered what type of alternative resources could replace the 469 MW of energy and capacity Minnesota Power receives from BEC4 to meet customer requirements under alternative path "c" if BEC4 were to shutdown in 2016. Minnesota Power looked at a range of alternative generating resources including renewable generation, small natural gas peaking units, and larger more efficient natural gas combined cycle generating sources. The Strategist Proview module was used to compare the alternative resources and to select the least cost replacement alternative for BEC4 in the shutdown alternative. The screening analysis demonstrated that there were two natural gas strategies that could reasonably be considered as replacement alternatives for BEC4 in Minnesota Power's generation fleet:

1) Direct Replacement: implementing a 1x1 combined cycle (408 MW) natural gas resource, a small bank of reciprocating engines and wholesale market purchases, or

2) Ownership Share Replacement: execute a strategy to procure a 469 MW share of a larger 2x1 combined cycle natural gas resource.

While the smaller 1x1 combined cycle and reciprocating engine option provides a more tailored fit to Minnesota Power's shutdown option for BEC4, the share of a larger 2x1 combined cycle resource (which is typically sized around 800 MW) could provide economies of scale that Minnesota Power wanted to ensure were not overlooked as an option to replace BEC4.

More details on the screening analysis conducted that resulted in these two primary replacement strategies are discussed later in this document and in Appendix A – Attachment 1: Screen Results.

3. Comparative Analysis Between BEC4 and Reasonable Replacement Alternatives

To verify the BEC4 Project was the best plan for Minnesota Power customers, Minnesota Power examined in greater detail alternative paths "a" and "b" to determine if they were reasonable to pursue. As will be described further in the Results section below, the delay of the BEC4 Project (alternative path "b") was deemed unreasonable to warrant continued evaluation largely due to the added cost burden and market risk it created for customers. Therefore, the remaining alternative path included the consideration of a BEC4 shutdown and determining a viable replacement alternative.

The screening analysis identified two natural gas resource alternatives closest in range to the BEC4 Project, as described in item 2 above. Minnesota Power performed an economic analysis comparing cost of the BEC4 Project to the cost of each natural gas option. Minnesota Power utilized the Strategist modeling package to conduct its comparative analysis between the options. More details of the results from the comparative analysis are discussed later in the document; however, the results of the analysis indicate that the BEC4 Project provides significant benefit over the natural gas alternatives.

As an extension of the comparative analysis, the BEC4 Project and replacement options were then stressed under varying industry conditions to validate the robustness of the decision for Minnesota Power customers. Single variables that are critical to the electric industry were increased and decreased and the power supply costs were compared between the BEC4 Project and natural gas replacement alternatives. The stressing of variables was included in the analysis to ensure and confirm that under varying conditions the BEC4 Project was still the most reasonable and lowest cost option for customers.

C. Results

1. Alternative Compliance Paths Considered for the BEC4 Project

By evaluating a wide range of environmental compliance alternatives for meeting MATS and MERA regulation requirements for BEC4, Minnesota Power is helping to ensure that the most reasonable and prudent strategy is implemented for its customers. The rest of this section gives a detailed overview of the three alternative paths evaluated and provides insight in to the reasonableness of each option.

a) Environmental Retrofit for BEC4 in 2016

The BEC4 Project implements environmental control technologies to meet the MATS Rule, MERA and a contemplative design for future ash regulations. The air emission technology options were narrowed down to a CDS with a fabric filter (as described in Section V). Also included as part of the BEC4 Project is the incremental cost to expand the dry ash landfill and the associated cost for handling the dry ash, which is a by-product from the CDS technology.

Installation of the environmental retrofit will be complete by 2016 and the total capital cost identified for Minnesota Power's portion[7] of the BEC4 Project is \$350M with \$12.5M of annual O&M costs for the period ending June 30, 2017.

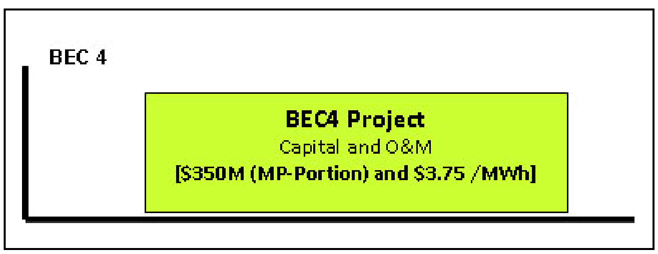

Figure 5. Environmental Retrofit at BEC4

b) Delay BEC4 Project with a Temporary Shutdown of BEC4 and Build a 213 MW Combustion Turbine in the Interim

The "Delay BEC4 Project" path contemplated a five year period from 2016 through 2020 in which BEC4 was not producing energy or providing capacity for Minnesota Power's system as it is shutdown awaiting an environmental retrofit after the MATS Rule deadline has passed (running the unit would put Minnesota Power out of compliance with MATS and at risk of EPA penalty until the retrofit is commissioned).

[7] The cost is net of WPPI Energy's share of the BEC4 Project costs.

This path also included implementing a new 213 MW combustion turbine resource built for Minnesota Power customers by 2016 to replace part of the 469 MW of capacity and 3 million MWh of energy removed from Minnesota Power's system because of the temporary shutdown at BEC4. The other energy and capacity requirements would be met by bilateral market purchases to meet the balance of the deficit created by the BEC4 shutdown. The combustion turbine could also position Minnesota Power for the long term capacity and energy requirements projected in the post 2025 period.

This option would delay the cost of the environmental retrofit for Minnesota Power customers by approximately five years and expedite adding a natural gas resource to protect the customer from extreme amounts of market purchase exposure during the BEC4 shutdown.

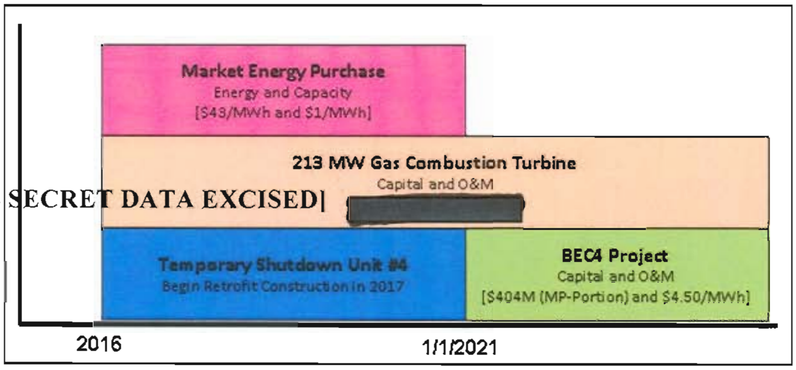

Figure 6. Delay BEC4 Project Installation with Temporary BEC4 Shutdown and Build a 213 MW Combustion Turbine in the Interim

This compliance path would prove to be ultimately beneficial if the MATS requirement were expected to dissolve or be significantly delayed for BEC4, bringing benefits to customers as the capital costs of a retrofit are pushed out or removed completely.

This path would create a significant energy and capacity replacement requirement as BEC4 is shutdown during the 2016 thru 2020 period, even with the addition of a new 213 MW combustion turbine there would still be over 200 MW of energy and capacity needed to maintain customer requirements currently being met by BEC4. Figures 7 shows the projected capacity outlook for Minnesota Power with a five year shutdown of BEC4.

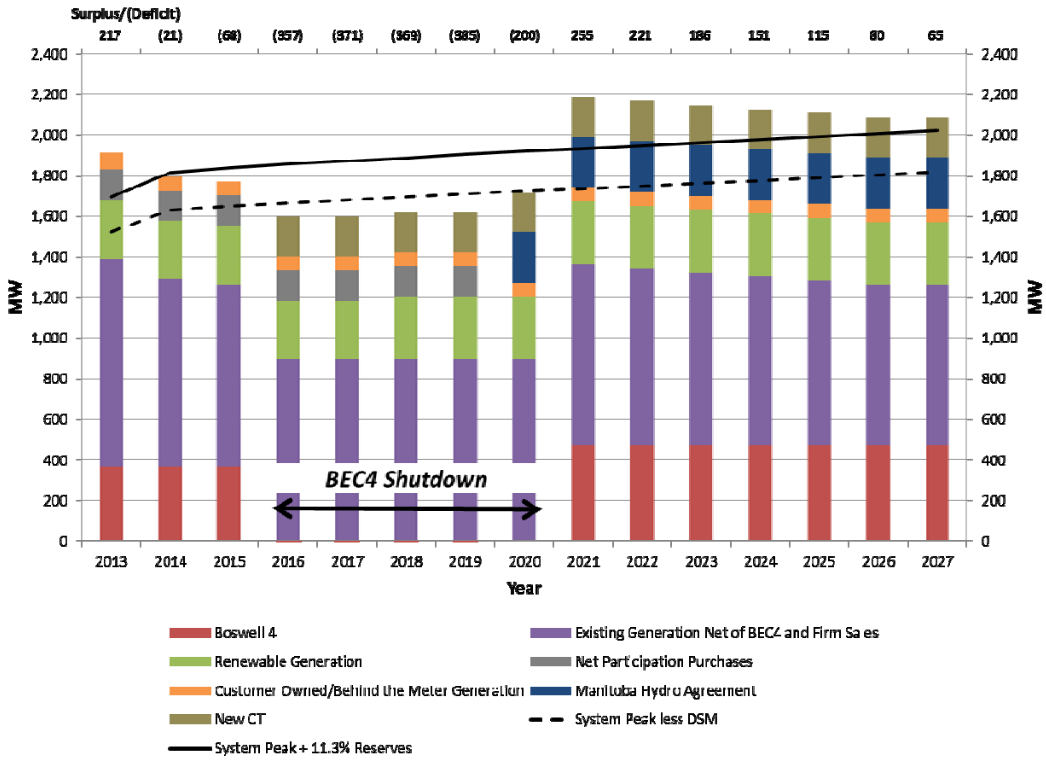

Figure 7. Minnesota Power Capacity Position Without BEC4 2016-2020 -- Five Year Shutdown

A combustion turbine is a peaking resource and only provides energy during periods of high energy demand. BEC4 is a baseload type resource and provides energy 7x24 to Minnesota Power customers. Due to the difference in operation between the combustion turbine and BEC4, only a small portion of the BEC4 energy will be replaced by the combustion turbine and the remaining energy is expected to be replaced by market purchases. Figure 8 which shows the large magnitude of projected energy needed during the five year shutdown of BEC4 – on average 27 percent of customer projected energy needs would be met with market purchases.

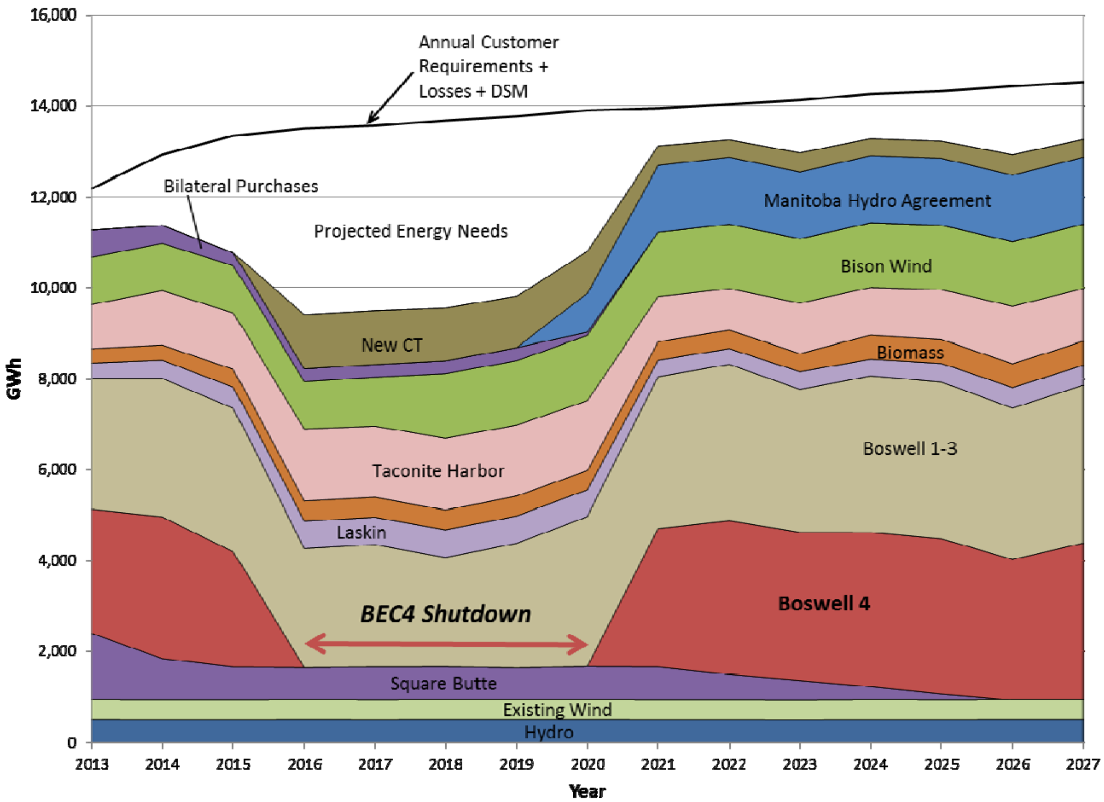

Figure 8. Minnesota Power Energy Position without BEC4 2016-2020 -- Five Year Shutdown

The retrofit delay option shown above has significant additional costs to customers that need to be considered. The increased cost can be attributed to the continued need to meet the fixed cost obligations of BEC4 during the shutdown, the capital cost of a new combustion turbine, and the replacement power cost risk associated with procuring such a large block of energy and capacity from the market for a five year period. For these reasons, Minnesota Power did not feel it was reasonable to move forward with "Delay BEC4 Project" compliance path as a viable option for its customers and did not conduct further evaluation.

c) Shutdown BEC4 in 2016 and Replace with Natural Gas Alternative

The option to not install the emission retrofit and remove BEC4 from Minnesota Power's power supply in 2016 would require both the significant action of shutting down the largest coal-fired resource in Minnesota Power's fleet and identifying a replacement resource or resources that would be able to cost effectively produce a similar energy production schedule as BEC4. A shutdown scenario for BEC4 would include decommissioning and remaining plant balance obligations and as in the baseload diversification study are considered as part of the economic analysis in this Petition. The socioeconomic costs for the host community and surrounding area would also need to be considered in the event of a temporary or permanent shutdown or repowering of BEC4.

Based on the results from the screening analysis described in the Petition, there were two natural gas replacement options identified as potential reasonable alternatives: 1) "Direct Replacement"- 1x1 combined cycle, reciprocating engines and wholesale market purchases or 2)

"Ownership Share" Replacement - ownership share of a 2x1 combined cycle. Each replacement option is described in more detail below:

1) Direct Replacement is a combination of an intermediate natural gas resource and a peaking natural gas resource, including a 1x1 combined cycle (408 MW[8]) and a bank of 6 reciprocating engines (55 MW) 449 MW of capacity. This combination of resources does not entirely replace BEC4's 469 MW of capacity; the remaining 20 MW of capacity is identified as being replaced by purchases from the wholesale power market. This option employs available technology that could be implemented by Minnesota Power and allows for the wholesale market to help optimize the replacement and at the same time keeping the market risk for customers at a minimum.

Replacement Option 1 "Direct Replacement":

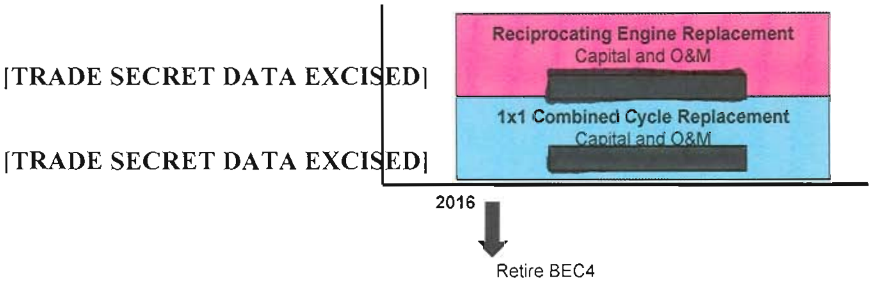

Figure 9. Reciprocating Engine — Combined Cycle Replacement

This combination of resource alternatives in the "Direct Replacement" option will require significant capital investment. Based on current technology planning estimates for 2012 the 1x1 combined cycle has a cost range of **[TRADE SECRET DATA EXCISED]**[9] and a reciprocating engine has a cost range of **[TRADE SECRET DATA EXCISED]** that could be realized by customers for these resource investments.

The operational costs of natural gas fired generation resources have different characteristics than a coal-fired unit. Being driven much more by fuel cost, the natural gas resources will have significantly larger percentages of fuel expense than a coal fired unit such as BEC4. Figure 9 below shows an estimate of annual cost categories for both the BEC4 including the BEC4 Project compared to the cumulative cost of the natural gas "Direct Replacement" option. The fuel expense for the 1x1 combined cycle resource, even at the low long term natural gas projections currently in place (average cost from 2016 thru 2035 of $6.50/MMBtu and $0.50/MMBtu delivery) are 60 percent greater than the BEC4 fuel expense. The fuel expense for the reciprocating engine is double BEC4's fuel expense.[10]

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[8] The 1x1 combined cycle size based on the annual operating conditions is 408 MW of capacity. For economic modeling in Strategist, the 394 MW of capacity for the 1x1 combined cycle is based on summer on-peak operating conditions.

[9] All $ per kW capital cost for the natural gas alternatives is based the size of the unit at the annual operating condition.

[10] The fuel cost comparison takes into consideration the efficiency of the 1x1 combined cycle, reciprocating engine and BEC4 - How much fuel it takes to produce one MWh.

Looking at the overall annual expenditures in Figure 9, it is clear that there is an annual economic benefit of adding the BEC4 Project to BEC4 in comparison to the gas resource mix in the "Direct Replacement" option – BEC4's annual cost is 21 percent lower ($52 million/year) than the annual cost for the "Direct Replacement" option.

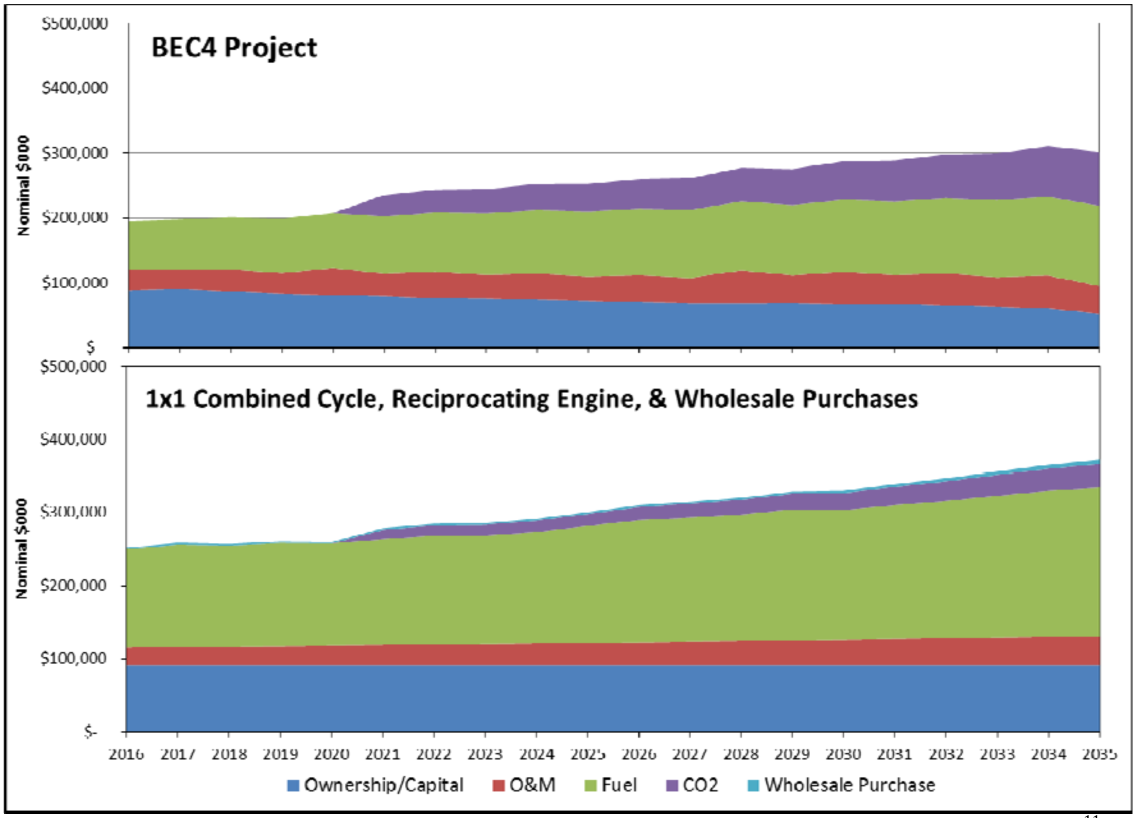

Figure 10. Comparison of the BEC4 with the BEC4 Project to the "Direct Replacement" Option[11]

2) Ownership Share Replacement includes implementing a replacement strategy to procure a 469 MW (or approximately 58 percent) ownership share of an 811 MW[12] 2x1 natural gas combined cycle generating resource. The 58 percent ownership share represents a direct replacement of the energy and capacity retired at BEC4. The 2x1 combined cycle natural gas resource is a more efficient generating station and being a larger size can offer lower cost energy on a per megawatt basis (see Appendix A – Attachment 2: Assumptions and Outlooks for more detail). However, this large generating station is a large enough resource that it is not conducive for a single entity to require the entire output. Evaluating this replacement option for the BEC4 Project assumes Minnesota Power can find a counterparty to invest in the remaining 342 MW share of the unit.

By evaluating both the Direct Replacement and Ownership Share options Minnesota Power is evaluating the lowest cost natural gas resource and the next lowest natural gas option that were showing benefit in the alternative screening analysis.

[11] The cost comparison assumed a baseload resource capacity factor of 80% for calculating variable O&M and fuel cost

[12] The 811 MW of capacity for the 2x1 Combined Cycle is based on annual operating capability. For economic modeling in Strategist the size of the unit was derated to reflect summer on-peak operating conditions of 785 MW.

Replacement Option 2 "Ownership Share": Retire BEC4 in 2016 and Replace with Combined Cycle Technology

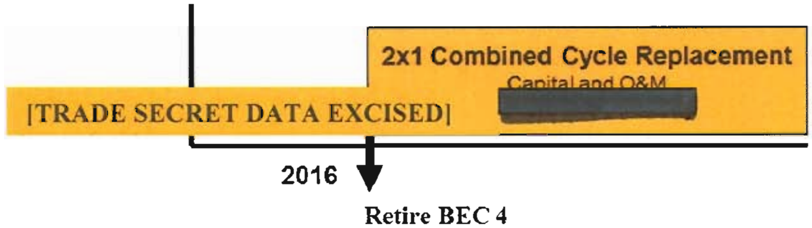

Figure 11. 2x1 Combined Cycle Replacement

A new 2x1 combined cycle includes significant capital investment requirements. Based on current technology planning estimates for 2012 there is a cost range of **[TRADE SECRET DATA EXCISED]** that could be realized by customers for a 2x1 combined cycle resource investment. Similar to the Direct Replacement option the operating costs of this natural gas option play an important role.[13] The cost range of a 2x1 combined cycle is also very sensitive to the cost of natural gas. Figure 10 shows an estimate of annual cost categories for both the BEC4 with the environmental retrofit compared to the 2x1 combined cycle resource alternatives. While the combined cycle resource brings the costs of a natural gas replacement closer to BEC4, there is still a clear annual economic benefit; BEC4's annual cost is 14 percent lower ($34 million/year) than the annual cost for "Ownership Share" replacement option.

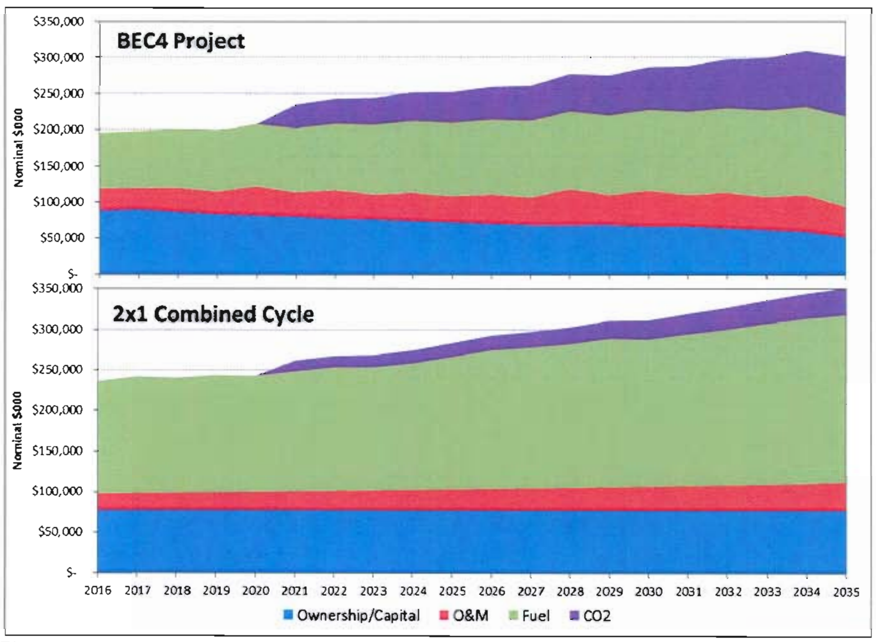

Figure 12. Comparison of BEC4 with the BEC4 Project to the "Ownership Share" Replacement Option[14]

[13] The fuel cost comparison takes into consideration the efficiency of fuel usage for the 2x1 combined cycle and BEC4 - How much fuel it takes to produce one MWh.

[14] The cost comparison assumed a baseload resource capacity factor of 80% for calculating variable O&M and fuel cost

Figure 10 also identifies that the annual fixed costs for both the 2x1 combined cycle resource and BEC4 (with the BEC4 Project) are very similar; allowing the lower fuel costs of BEC4 to generate more value for the customers.

There are other benefits that natural gas resources like a combined cycle or reciprocating engine can bring to Minnesota Power customers. Compared to a large baseload coal resource, like BEC4, a combined cycle or reciprocating engine has more flexible operation and can follow wind generation better than a large coal unit, especially the reciprocating engine alternative. The combined cycle is also a more efficient resource, meaning it takes less fuel than BEC4 to generate 1 MWh of energy. The greater fuel efficiency of a combined cycle equates to less fuel consumption by volume and less emissions such as mercury, SO_2, NO_x and carbon when compared to a large coal unit such as BEC4. To fully evaluate the impact of integrating the replacement alternatives into Minnesota Power's system it is necessary to go to a production cost evaluation of each option that takes into consideration more of the variables that drive an implementation decision.[15] The next Comparative Analysis section will show this analysis and give additional insight on how the BEC4 Project continues to be in the best interest of customers compared to the natural gas alternatives.

D. Comparative Analysis Shows BEC4 is Best Alternative

The BEC4 Project provides a decisive range of benefits for Minnesota Power customers over the two natural gas replacement options; from $210 million to $373 million of savings was identified over the study period. The most significant confirmation to move forward with the BEC4 Project was to look in greater detail at the two natural gas replacement options, "Direct Replacement" and "Ownership Share," to ensure the BEC4 Project remained the best option for Minnesota Power's customers over the long term planning horizon. Each of the natural gas alternatives were evaluated and compared against the BEC4 Project implementation at BEC4 under a range of planning sensitivities. This significant benefit along with a rigorous sensitivity analysis and validation by a third party[16] gave Minnesota Power confidence that the BEC4 Project was in the best interest of its customers.

The Strategist production cost software was utilized for the 2012-2035 study period to help quantify the expected range of impact that the BEC4 Project would bring the customer power supply costs compared with the two replacement natural gas options.[17]

To ensure that only the impact of the BEC4 Project or the two replacement options were being captured in the comparative analysis, the remaining capacity and energy requirements of Minnesota Power systems over the study period were held constant in the evaluation. This

[15] Minnesota Power utilized the Strategist software for its production cost evaluation of the replacement alternatives for BEC4.

[16] Minnesota Power requested that PACE Global Inc, independently evaluate the BEC4 Project decision, along with the mechanics of the analysis described in this section, to ensure that moving forward was seen as prudent from a third party perspective.

[17] The cost comparison was conducted under a 'No Energy Market' and a 'With Energy Market' condition to provide confirmation that the BEC4 Project was prudent under both resource planning assumptions. Minnesota Power utilizes a 'With Energy Market' for its planning outlooks as the availability and flexibility that a regional market provides is an important benefit to Minnesota electric customers as resource decisions and timing are determined. For the evaluation of the BEC4 Project, both 'With Energy Market' and 'No Energy Market' identify that moving forward with the environmental retrofit is in the best interest of Minnesota Power's customers.

assumption allowed the BEC4 Project to be replaced with either natural gas replacement option interchangeably so that the Present Value of Revenue Requirements ("PVRR") of the power supply costs could be directly compared to accurately analyze the effects of each option.[18]

Typical to Minnesota Power's proactive planning process, a range of sensitivities were included in the comparative analysis to stress the BEC4 Project and its alternatives. The following is a list of the sensitivities that were stressed in both high and low conditions, and included in the comparative analysis (See Appendix A- Attachment 2: Assumptions and Outlooks for more sensitivity analysis detail):

- Capital cost for replacement alternatives and the BEC4 Project
- Delivered coal prices
- CO_2 regulation penalty
- Customer loads
- Market energy price
- Natural gas price at Henry Hub
- State externality values
- Demand side management
- Stringent EPA Cost for BEC4 from the Baseload Diversification Study

Tables 1 and 2 provide the results of the comparative analysis for both the 'Direct Replacement' and 'Ownership Share' natural gas alternatives. Each demonstrate a comparison of the Strategist power supply costs, represented by the PVRR value, with the BEC4 Project and the change in those costs that occur when the two replacement options are utilized. The values are provided in the first table, Table 1 for the 'With Energy Market' condition and then for the 'No Energy Market' condition in Table 2. Each table includes the outcome of the series of sensitivities identified above. A negative value in the natural gas replacement option column indicates the natural gas resource alternative provides a savings to customers relative to the BEC4 Project. The sensitivities identified that there were very limited conditions where the natural gas alternatives would provide benefit to Minnesota Power's customers. When the BEC4 Project is compared to the two natural gas resource alternatives, the BEC4 Project is the lowest cost outcome for customers in a majority of the sixteen sensitivities examined in this analysis.

The BEC4 Project was found to have the best performance when compared to the 'Direct Replacement' option, including under the variety of sensitivities evaluated, providing a range of approximately $373 million in benefit to customers under the Base Case assumptions and up to $679 million in the high natural gas sensitivity. The BEC4 Project was also found to have the best performance when compared to "Ownership Share" replacement option, but not to the same

[18] The Baseload Diversification Study indicated that BEC4, with additional air environmental retrofit technology, was in the best interest of Minnesota Power customers and part of a least cost system wide expansion plan. The comparative analysis being described gave additional merit to the findings of the Study and allowed this evaluation to concentrate on the two natural gas alternatives in comparison to the BEC4 Project.

magnitude of benefit as seen in the comparison to the 'Direct Replacement' option; benefit ranged from $210 million under the Base Case assumptions and up to $530 million in a high natural gas future. This was expected as the 'Ownership Share' replacement alternative provided Minnesota Power access to a piece/ownership share of a larger, more efficient natural gas option.[19]

[19] The difference in the benefit of the BEC4 Project when compared to the two replacement options is due to the economies of scale realized when building a large 2x1 combined cycle in "Ownership Share" replacement option – The $ per kW capital cost of the alternatives is lower for a 2x1 combined cycle **[TRADE SECRET DATA EXCISED]** than the 1x1 combined cycle **[TRADE SECRET DATA EXCISED]** and the reciprocating engines **[TRADE SECRET DATA EXCISED]**. As a reminder, for the economics to work for the 2x1 combined cycle in the "Ownership Share" option, it is assumed Minnesota Power would be able to find a counterparty to invest in the remaining share of the large asset. Otherwise, the stranded capital and operating cost from the remaining share of the 2x1 combined cycle is the responsibility of Minnesota Power and the customers, these stranded cost were not considered in the comparative cost analysis and would identify more benefit for the BEC4 Project alternative.

Table 1 – Strategist Scenario Cost Comparison 'With Energy Market' Condition

Strategist PVRR power supply cost comparison The BEC4 Project vs. Natural Gas Resource Alternatives			
Table shows the increase/decrease in costs when the BEC4 Project is either replaced with the natural gas resources in Replacement Option 1 or 2	**With the Energy Market Outlook**		
	***Power Supply Costs for the BEC4 Project Alternative**	**Change in Cost with the "Direct Replacement" Option Additional Cost (Less Cost)**	**Change in Cost with the "Ownership Share" Replacement Option Additional Cost (Less Cost)**
Base	$8,093,506	$373,160	$209,821
High Capital Cost	$8,205,945	$406,793	$228,274
Low Capital Cost	$7,981,068	$339,525	$191,371
CO2-$40 Start in 2021	$9,378,273	$89,498	($58,624)
CO2-$0	$7,501,205	$480,026	$320,155
High Coal Forecast	$8,615,016	$231,830	$67,212
Low Coal Forecast	$7,668,684	$513,217	$349,724
High Externality Values	$8,077,939	$407,188	$246,442
Low Externality Values	$7,557,853	$477,724	$315,998
Plus 50% Natural Gas Forecast	$8,183,541	$679,227	$530,343
Minus 50% Natural Gas Forecast	$8,046,904	($101,094)	($292,355)
High Load Forecast	$8,371,828	$359,524	$197,164
Low Load Forecast	$6,944,126	$369,296	$206,258
Plus 50% Wholesale Mkt Forecast	$8,573,016	$355,967	$153,475
Minus 50% Wholesale Mkt Forecast	$7,572,637	$291,041	$152,997
DSM Alternative 2 Combination	$8,093,506	$362,640	$199,179
Stringent EPA	$8,161,524	$305,142	$141,804

* Power supply costs modeled in Strategist for the 2012-2035 study period

- Dollar amounts are shown in thousands and represent the present value of power supply cost is 2012 dollars over the study period

As shown by the PVRR differences in Table 1, the relative cost of the BEC4 Project is highly sensitive to gas price volatility and potential future carbon regulation. Even though the low gas sensitivity indicates the potential for customer benefit with the natural gas resource alternatives when compared to the BEC4 Project, the benefit is driven by an assumption of sustained, long term low natural gas pricing that is below even the current, record low outlooks. While Minnesota Power included this sensitivity to validate this book-end condition for natural gas prices, it does not believe there is a high probability of sustained natural gas production at the levels in the Minus 50% Natural Gas sensitivity (average delivered costs of $3.50/mmbtu) to 2034.

Another key indication of the economic benefit that BEC4 brings to Minnesota Power's customers is shown above where the High (Plus 20%) Coal Forecast continued to demonstrate that the BEC4 Project was the lowest cost option compared to the two natural gas replacement options. This clarifies that if the fuel costs for BEC4 are 20 percent higher than expected, the BEC4 Project still shows a benefit for customers, relative to the replacement options. This is another strong indication of the benefit that BEC4 provides Minnesota Power's high energy consuming customers and the need for BEC4 as a baseload resource to meet ongoing energy and capacity requirements.

Table 2 provides the results of the comparative evaluation under a 'No Energy Market' condition. Similar to the comparative analysis results in the 'With Energy Market' condition, the BEC4 Project was again found to have the best performance when compared to either the "Direct Replacement" or the "Ownership Share" natural gas replacement options.

Table 2 – Strategist Ccenario Cost Comparison for the 'With No Energy Market' Condition

Strategist PVRR Comparison The BEC4 Project vs. Natural Gas Resource Alternatives			
Table shows the increase/decrease in costs when the BEC4 Project is either replaced with the natural gas resources in Replacement Option 1 or 2	**With No Energy Market Outlook**		
	***Power Supply Costs withthe BEC4 Project**	**Change in Cost with the "Direct Replacement" Option Additional Cost (Less Cost)**	**Change in Cost with the "Ownership Share" replacement Option Additional Cost (Less Cost)**
Base	$8,574,928	$468,496	$172,087
High Capital Cost	$8,687,366	$502,131	$190,536
Low Capital Cost	$8,462,489	$434,864	$153,635
CO2-$40 Start in 2021	$10,089,566	$183,771	($113,593)
CO2-$0	$7,940,083	$595,966	$301,178
High Coal Forecast	$9,175,985	$302,892	$2,566
Low Coal Forecast	$8,083,382	$625,300	$329,774
High Externality Values	$8,583,827	$517,044	$217,865
Low Externality Values	$8,005,306	$594,312	$296,786
Plus 50% Natural Gas Forecast	$8,664,963	$970,149	$670,957
Minus 50% Natural Gas Forecast	$8,528,326	($74,336)	($387,724)
High Load Forecast	$9,234,637	$490,920	$135,788
Low Load Forecast	$7,022,990	$311,674	$165,197
Plus 50% Wholesale Mkt Forecast	$8,738,524	$462,969	$166,558
Minus 50% Wholesale Mkt Forecast	$8,473,738	$474,081	$177,671
DSM Alternative 2 Combination	$8,574,928	$424,869	$134,039
Stringent EPA	$8,642,945	$400,479	$104,069

* Power supply costs modeled in Strategist for the 2012-2035 study period
- Dollar amounts are shown in thousands and represent the present value of power supply cost is 2012 dollars over the study period

This outcome demonstrates that under either planning assumption for the use of regional energy markets, BEC4 continues to be the superior resource for Minnesota Power's customers.

While the BEC4 Project provides significant reductions of several significant air emission categories such as mercury (see Section V) Minnesota Power realizes that the BEC4 Project does not contribute to additional carbon emission reductions. However, Minnesota Power has been taking significant steps as part of its larger Integrated Resource Plan strategy and specifically its short and long term action plans over the last five years to reduce the carbon concentration on the system. Specific actions already taken include:

1) Phasing out of Minnesota Power's ownership share of Square Butte's Young 2 coal-fired facility in the 2012 thru 2025 time period.
2) Adding 400 MW of wind generation to its power supply by end of 2012 including Oliver County I, II, Taconite Ridge, and Bison 1, 2, and 3 projects.
3) Purchasing 250 MW of hydro generation from Manitoba Hydro starting in 2020
4) Replacing BEC4 turbine rotors in 2010, producing 50 MW of emission and carbon free energy.

Minnesota Power's resource strategy continues to identify that it will pursue additional projects like those listed that reduce the carbon concentration of its power supply. Through the BEC4 Project and continued operation of BEC4, Minnesota Power is able to balance the costs of environmental compliance and keeping a power supply that is both reasonable and reliable for its customers.

Appendix A – Attachment 1: Screening Results

A. Screening of Power Generation Alternatives

This appendix clarifies how Minnesota Power screened which power generation alternative(s) were included in the comparative sensitivity analysis. Both the screening and comparative sensitivity analysis were performed using Strategist. The screening was a necessary first step to reduce the comparative analysis to a direct comparison between the BEC 4 Project and one or two replacement alternatives.

The replacement resource options include renewable resources, mature natural gas-fired technologies, and the developing CO_2 sequestration technology combined with mature coal-fired technology. Minnesota Power has included all committed and approved renewable projects and long-term bilateral purchases in the screening and comparative base and sensitivity cases. This includes the **[TRADE SECRET DATA EXCISED]**.

The following list contains the set of resource technologies that were considered in the initial screening process.

B. New Thermal Generation

- Coal-fired (with carbon capture):
  - Supercritical Pulverized Coal (SCPC)

- Natural gas-fired:
  - Simple Cycle Reciprocating Internal Combustion Engine (SC RICE)
  - Simple Cycle Combustion Turbine (SC CT)
  - Simple Cycle Aero Derivative (SC Aero)
  - Combined Cycle (CCGT)

C. Renewable Generation

Minnesota Power has been committed to the development of renewable resources in order to meet the RES requirements in accordance with Minnesota Statute § 216B.1691. Since the filing of the 2010 Plan, Minnesota Power has committed to building 292 MW of wind generation in North Dakota by the end of 2012 (Bison 1, 2, and 3 Wind Projects). The Bison Wind Projects, along with other renewable projects Minnesota Power is committed to, have been included in the expansion plan for the analysis.

A generic North Dakota wind farm (ND Wind) and new biomass technologies were included as renewable resource options in the screening process. Both have been identified as proven renewable resource options and are outlined in more detail in Appendix A – Attachment 2: Assumptions and Outlooks of this report.

D. Demand-Side Management and Conservation (beyond current forecasts levels)

Minnesota Power remains a state leader in the successful implementation of its conservation programs, and meeting and exceeding the 1.5 percent goal established by the Next Generation Energy Act. All historic and current conservation impacts that meet the 1.5 percent energy savings goal are being reflected in Minnesota Power's 2012 AFR and associated energy and demand forecasts.

As part of the 2010 Resource Plan, a study was conducted to identify two additional conservation levels that create conservation opportunities above programs now in place (see Appendix B-Part 2 of the 2010 Plan). The resource option utilized in the analysis is based on the expanded conservation scenario Alternative 2 (approximately 13 MW). Minnesota Power's long-term plan identified that the 13 MW alternative was part of its least cost plan and committed to exploring additional conservation options in the future.

For this screening analysis, the economic feasibility of the conservation alternative was considered as a sensitivity scenario to determine if the inclusion of additional DSM would impact the relative economic impact of the BEC4 retrofit compared to the replacement alternatives.

E. Screening Analysis Results

The screening analysis was performed utilizing Strategist's Proview module. For the screening, BEC4 was retired in 2016 and each replacement alternative was available for selection within Proview at a project size similar to BEC4's summer capacity rating. For some of the alternatives, this meant more than one unit was available. Except for the already approved future bilateral purchases and renewable projects previously discussed, no other expansion plan decisions were allowed as part of the screening analysis. Each replacement alternative included the estimated capital cost, transmission, O&M (fixed and variable), fuel costs, and associated emissions.

The replacement alternative selected in the least cost plan identified in Proview was a combination of a 1 x 1 CCGT and 6 x SC RICE generation resources. This combination had an approximate summer capacity of 449 MW, which is 20 MW less than BEC4's summer capacity. Figure 1 shows the $/MWh levelized busbar cost of power at a capacity factor similar to BEC4's typical operation for each replacement alternative considered. Note that the Wartsila unit included in Figure 1 is the manufactures name of a SC RICE technology.

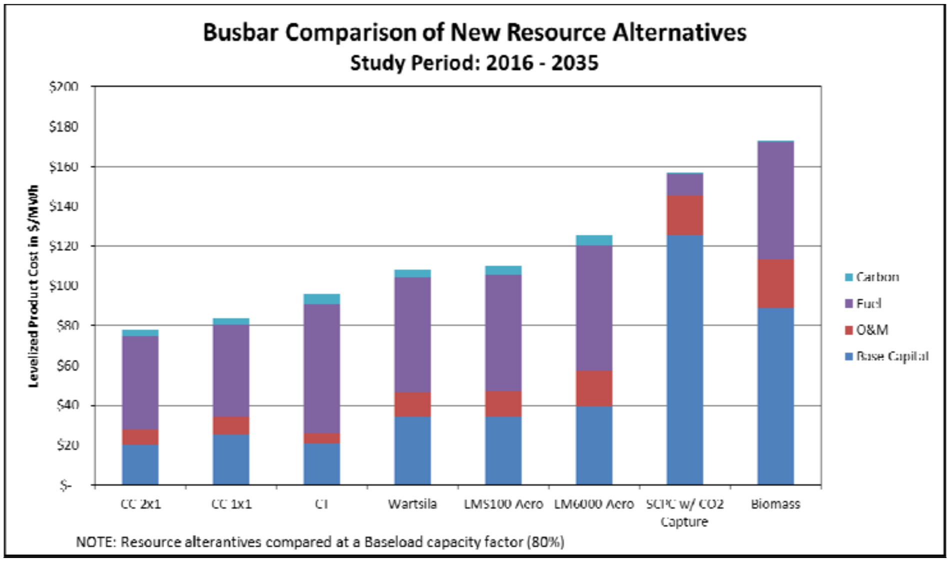

Figure 1--20 Year Option Levelized Busbar Cost

Figure 1 shows that the 2 x 1 CCGT alternative has the lowest levelized busbar cost at the assumed capacity factor. However, the 2 x 1 CCGT alternative has a summer capacity rating of 785 MW which is significantly greater than the capacity of BEC4. The combination of alternatives selected in the more detailed Strategist Proview screening analysis results was closer to the output of BEC4 and represented the next lowest cost combination of resources that could provide lower cost energy.

Appendix A – Attachment 2: Assumptions and Outlooks

The following section provides a summary of the key economic modeling assumptions that Minnesota Power utilized in the Strategist Proview analysis completed for the BEC4 Mercury Emission Reduction Plan Petition.

A. Base Case Economic Modeling Assumptions

Study Period

1. The timeframe of this analysis is 2012 thru 2035.

Pricing and Wholesale Market

2. The base forecasts utilized for market energy prices, market capacity prices, CO_2 costs, and natural gas prices over the study period[1]:

    a. Carbon cost range: \$10/tonne starting in 2021 to \$25/tonne in 2035

    b. NOx cost range: \$632/ton starting in 2012 to \$0/ton in 2035

    c. SO_2 cost range: \$571/ton starting in 2012 to \$0/ton in 2035

    d. Natural Gas at Henry Hub: \$4/MMBtu in 2012 to \$8/MMBtu in 2035

    e. Wholesale Market Capacity: \$200/MW-month in 2012 to \$11,100/MW-month in 2035

    f. Wholesale Market Energy: \$34/MWh in 2012 to \$75/MWh in 2035

3. The economic modeling was done in the Strategist Proview module under two broad scenarios that allowed the wholesale energy market to be turned on and off as a power supply resource. These scenarios were included to ensure the outcome of the analysis was not impacted by the availability of the regional wholesale energy market. A more detailed description of each is provided below.

    a. <u>With Wholesale Energy Market</u> ("With Market") – A conservative approach was taken when creating the wholesale energy market that would be made available as a power supply resource during the study period. To help account for the increased risk and volatility that is present when purchasing incrementally larger amounts of energy from the market, an increasing price adder was included based on the level of energy purchased. As the volume of energy purchased from the market increased, so did the price adder. This is referred to as a 'Tiered Energy Market' and includes the following pricing assumptions:

        i. 0 to 150 MW at forecast price

        ii. 151 to 300 MW at forecast price plus \$15/MWh premium adder

        iii. 301 to 600 MW at forecast price plus \$40/MWh premium adder

        iv. Greater than 600 MW at emergency energy price (\$250/MWh in 2012 and escalates at 2.1% annually)

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[1] Values are in nominal dollars

b. Without Wholesale Energy Market ("No Market") – The Tiered Energy Market was turned off starting in 2016 in this scenario and only Emergency Energy at $250/MWh was made available during the model run. As this scenario did not provide for purchasing energy from the wholesale energy market during hours of generation unit planned and forced outages, the planned outages and forced outages for Minnesota Power's generation resources were removed from the model.

   This scenario was included to address feedback received during Minnesota Power's 2010 Plan process and Baseload Diversification Study that identified long-term expansion plan modeling could be done with no energy procured from an energy market.

4. Wholesale market capacity was made available for the model during all modeling runs at prices identified in bullet 2e previously. Because this analysis focused on the retrofit decision at BEC4, generation expansion plans were held constant between scenarios and any capacity shortfalls were provided by short term wholesale market capacity. Generally, this amounted to approximately 200 MW of capacity by 2035 except for sensitivities around the base load forecast.

Minnesota Power Resources and Power Transactions

5. **[TRADE SECRET DATA EXCISED]**

6. **[TRADE SECRET DATA EXCISED]**

7. Installation of wind capacity (Bison wind projects) is consistent across all scenarios with Minnesota Power's current renewable energy strategy. The Bison 2 and Bison 3 wind farms are installed by late 2012 and the last remaining wind farm project is included to fulfill the remaining Renewable Energy Standard requirements.

8. Natural gas supply prices reflect the projected spot market at Henry Hub with a regional delivery charge of $0.40/MMBtu for the fuel supply of all gas generation modeled in the petition. The delivery charge was escalated at 2.1% annually after 2012.

9. The emission rates for the thermal generation units included in Strategist are modeled as tons or pounds per MMBtu of coal consumed for energy production. The level of effluents emitted per MWh generated will vary depending on the output level of a generation facility. As a generator is dispatched to a lower output level because of economic conditions the effluents emitted per MWh will increase due to the generator operating at a less optimal level when compared to running at full output. The emission rates modeled in Strategist are:

   a. Carbon
   b. Carbon Dioxide
   c. Lead
   d. Mercury
   e. Nitrogen Oxide
   f. Particulate Matter 10
   g. Sodium Dioxide

Minnesota Power Load and General Economic Assumptions

10. Customer energy and demand requirements are based on the Wholesale and Industrial Customer Addition Forecast Scenario in the 2012 Minnesota Power's Annual Electric utility Report.

11. Capacity accreditation values for generators are the installed capacity (ICAP) and are based on MISO's Planning Year 4 generation performance test results per the Module E Resource Adequacy program.

12. Planning reserve margins based on MISO's required reserve margin of 11.32%.

13. The utility discount rate is the weighted average cost of capital (WACC) for Minnesota Power based on current capital structure and allowed return on equity. The utilized discount rate is 8.18%.

14. General escalation rate of 2.1% was utilized, except for capital cost and O&M for new generation which is escalated at 3% per year.

B. Asset Resource Alternatives Evaluated

The resource alternatives that were screened as possible replacement options for BEC4 are included below. The capital costs were based on Minnesota Power's most current planning estimates for such resources.

1. Ownership share of 200 MW natural gas 1x1 combined cycle resource
    a. Capital build cost plus transmission upgrade costs in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.
2. Ownership share of 200 MW natural gas 2x1 combined cycle resource
    a. Capital build cost plus transmission upgrade costs in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.
3. 213 MW natural gas combustion turbine resource
    a. Capital build costs plus transmission upgrade cost in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.
4. 104 MW natural gas aero-derivative unit
    a. Capital build costs plus transmission upgrade cost in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.
5. 49 MW natural gas aero-derivative unit
    a. Capital build costs plus transmission upgrade cost in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.
6. 55 MW natural gas reciprocating engines (6 x 9.2 MW engines)
    a. Capital build costs plus transmission upgrade cost in 2012 dollars is [**TRADE SECRET DATA EXCISED]**.
7. 105 MW wind farm located in North Dakota
    a. Capital build costs plus transmission upgrade costs in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.

8. 50 MW biomass fired generation facility
    a. Capital build costs plus transmission upgrade costs in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.
9. 486 MW super critical pulverized coal generation asset that is ready for CO_2 capture equipment.
    a. Capital build costs plus transmission upgrade costs in 2012 dollars is **[TRADE SECRET DATA EXCISED]**.
10. 13 MW to 33 MW of demand side management and conservation
    a. The costs of implementing demand side management ranges from $43/MWh to $136/MWh in levelized dollars over the life of the of the conservation programs assessed in the 2010 Plan.
    b. The methodology utilized by Minnesota Power when modeling and developing demand side resource alternatives is included in Appendix B of the 2010 Plan.

Explanation of the capital cost of resource alternatives considered in the comparative analysis for the Petition.

1. Replacement Option 1 "Direct Replacement": Based on current technology planning estimates for 2012 the 1x1 Combined Cycle has a cost range of **[TRADE SECRET DATA EXCISED]**[2] and a Reciprocating Engine has a cost range of **[TRADE SECRET DATA EXCISED]** that could be realized by customers for these resource investments. The projected outlook for capital requirements of the 1x1 Combined Cycle resource is currently **[TRADE SECRET DATA EXCISED]** (2012 dollars) which would equate to **[TRADE SECRET DATA EXCISED]** of capital investment by 2016, after escalation. The projected outlook for capital requirements of the Reciprocating Engine resource is currently **[TRADE SECRET DATA EXCISED]** (2012 dollars) which would equate to **[TRADE SECRET DATA EXCISED]** of capital investment by 2016, after escalation.
2. Replacement Option 2 "Ownership Share": Based on current technology planning estimates for 2012 there is a cost range of **[TRADE SECRET DATA EXCISED]** that could be realized by customers for a 2x1 Combined Cycle resource investment. The expected outlook for capital requirements of the 2x1 Combined Cycle resource is currently **[TRADE SECRET DATA EXCISED]** (2012 dollars) which would equate to **[TRADE SECRET DATA EXCISED]** of capital investment by 2016, after escalation, for a 485 MW ownership share of the 2x1 Combined Cycle unit.

C. Variables Stressed high or low and Scenario Sensitivities utilized in the Sensitivity Analysis

The following variables were stressed low and high in the single variable sensitivity analysis.

1. Wholesale market energy

[2] All $ per kW capital cost for the natural gas alternatives is based the size of the unit at the annual operating condition.

a. The low sensitivity is decreased by 50% from base: $17/MWh in 2012 to $38/MWh in 2035.

b. The high sensitivity is increased by 50% from base: $52/MWh in 2012 to $113/MWh in 2035.

2. Natural gas price forecast at Henry Hub

   a. A low sensitivity representing a decrease of 50% from base: $2/MMBtu in 2012 to $4/MMBtu in 2035.

   b. A high sensitivity representing an increase of 50% from base: $6/MMBtu in 2012 to $12/MMBtu in 2035.

3. Carbon costs[3]

   a. The low sensitivity reduced carbon cost to $0/tonne throughout study period

   b. A high sensitivity based on the high carbon value from the 2011 Order Establishing 2011 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06,in Docket No. E-999/CI-07-1199. The carbon cost is an external cost with a range as follows: $20/tonne starting in 2012 to $31/tonne in 2035.

   c. A high sensitivity based on the high carbon value from the 2011 Order Establishing 2011 Estimate of Future Carbon Dioxide Regulation Costs, pursuant to Minn. Stat. §216H.06,in Docket No. E-999/CI-07-1199. The carbon cost is an external cost with a range as follows: $37/tonne starting in 2021 to $50/tonne in 2035.

4. Externality costs

   a. The low sensitivity was based on the low externality Metropolitan Fringe values from Environmental and Socioeconomic Costs, Docket Nos. E-999/CI-93-583 and E-999/CI-00-1636 for SO_2, PM10, CO, NO_x, Pb, and CO_2.

   b. The high sensitivity was based on the high externality Metropolitan Fringe values from Environmental and Socioeconomic Costs, Docket Nos. E-999/CI-93-583 and E-999/CI-00-1636 for SO_2, PM10, CO, NO_x, Pb, and CO_2.

5. Coal fuel prices

   a. A low sensitivity reduced coal prices by 20% from base.

   b. A high sensitivity which increases coal prices by 20% from base.

This range was considered based upon stakeholder feedback in the Baseload Diversification Study process, as a wide range of cost compared to historical costs.

6. Capital costs

[3] All carbon allowance prices reflect dollars per metric tonne

a. The low sensitivity reduced capital costs on average by 20% from base for new generation alternatives and reduced capital costs by 25% from base for the BEC4 retrofit. The percentage decrease in capital cost varied by resource types.

b. The high sensitivity increased capital costs on average by 20% from base for new generation alternatives and increased capital costs by 25% from base for the BEC4 retrofit. The percentage increase in capital cost varied by resource types.

7. Customer sales forecast

   a. The low sensitivity is based on the Low Economic and Industrial Forecast Scenario in the 2012 Minnesota Power's Annual Electric utility Report

   b. The high sensitivity is based on the Moderate Industrial Expansion Forecast Scenario in the 2012 Minnesota Power's Annual Electric utility Report

8. Additional DSM

   a. A scenario was developed based on the inclusion of the expanded conservation scenario Alternative 2 as defined in the 2010 Plan in combination with the replacement alternative to the BEC4 retrofit project.

9. Stringent EPA

   a. A scenario was developed where additional environmental capital costs were added to BEC4 based on compliance under the Stringent EPA scenario as defined in the Baseload Diversification Report.

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of Minnesota Power's Annual Filing In Compliance with Minn. Stat. §216B.6851, subd. 5	Docket No. E015/M-11-___
	2011 REPORT

****

SUMMARY OF FILING

Minnesota Power submits this 2011 Report to the Minnesota Public Utilities Commission ("Commission") in compliance with Minn. Stat. §216B.6851, subd. 5. Through this Report, Minnesota Power provides the Commission, the Minnesota Pollution Control Agency, the Department of Commerce – Division of Energy Resources and other stakeholders information describing the status of the Company's planning and analysis process related to compliance on mercury reduction and other pending emission reduction regulations at its Boswell Energy Center Unit 4 ("BEC4"). Minnesota Power continues to actively monitor and assess the progress of the same federal environmental rule makings that were cited to support extending the BEC4 mercury reduction plan filing and plan implementation timelines under the Mercury Emission Reduction Act during the 2010 legislative session. Minnesota Power's analysis concludes that, based on relevant federal rulemaking status and the major multi-emission reduction investment expected eventually on BEC4, Minnesota Power should continue to postpone its decision as to what mercury reduction plan is appropriate for BEC4 and its customers.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

****

In the Matter of Minnesota Power's Annual Filing In Compliance with Minn. Stat. §216B.6851, subd. 5	Docket No. E015/M-11-___
	2011 REPORT

****

I. INTRODUCTION AND LEGISLATIVE HISTORY

Minnesota Power submits this Report to the Minnesota Public Utilities Commission ("Commission") in compliance with Minn. Stat. §216B.6851, subd. 5 as required under Minnesota's Mercury Emissions Reduction Act ("MERA"). Through this Report, Minnesota Power provides the Commission, the Minnesota Pollution Control Agency ("MPCA"), the Department of Commerce – Division of Energy Resources ("Department"), and other stakeholders insight into its planning and analysis process as Minnesota Power evaluates how best to achieve compliance with Minnesota's mercury reduction regulations at its Boswell Energy Center Unit 4 ("BEC4"). In addition to Minnesota's mercury reduction statute for utilities, environmental rule making pending at the federal level that addresses multiple criteria pollutants, anticipated customer rate impacts from future emission reduction investments and concerns about ensuring the prudence of the overall emission reduction investment at BEC4 all warrant Minnesota Power's thoughtful and strategic approach to meeting the Minnesota mercury reduction mandate.

The Minnesota Mercury Emissions Reduction Act was signed into law on May 11, 2006. The Act targeted six generating units at Minnesota's three largest coal-fired power plants.[1] The original legislation called for Minnesota Power to file with the Commission a 90 percent mercury reduction plan for one of its two wet-scrubbed units, Boswell Energy Center Unit 3 ("BEC3"), by December 31, 2007, with plan implementation by December 31, 2010. The mercury reduction plan for Minnesota Power's second unit, BEC4, was to be filed with the Commission

[1] Minnesota's three largest coal-fired power plants at the time the legislation was enacted were: Xcel Energy's Sherco and Allen S. King plants and Minnesota Power's Clay Boswell Plant ("BEC").

by July 1, 2011, with plan implementation completed by December 31, 2014.[2] Minnesota Power filed the Boswell 3 mercury reduction plan[3] early and successfully completed the project a year before the deadline.

Minnesota Power sought support for the bill introduced and passed during the 2010 legislative session that called for a change to MERA to increase Minnesota Power's flexibility in assessing, planning for and implementing mercury and other emission reductions at BEC4. The bill allowed for an extension to the time period for the filing of the BEC4 mercury reduction plan and an extension to the date by which the plan must be implemented. With federal environmental rule making in process for multiple emissions over the next few years that could affect BEC4, and Minnesota Power rate increases filed in 2008 and 2010, in part, to recover costs related to other mandated environmental retrofits, Minnesota Power believed mercury emission reduction investment for BEC4 was not a prudent or well-timed investment in the near-term. By making a mercury reduction investment under the original statutorily imposed timeline, Minnesota Power would be subjecting its customers to the rate impact of installing mercury reduction equipment on BEC4 that could quickly become obsolete or need to be removed prior to being utilized to the fullest extent of its useful life if pending federal rule making affecting BEC4 for other criteria pollutants was established. Utility emission reduction projects typically result in equipment installations to remove various emissions that must work in concert. Installing equipment on a generating unit for a single emission, such as mercury, is usually not prudent when other types of emission reduction installations are possibly going to be required on the unit nearer term.

The bill extending the plan filing date for BEC4 to July 1, 2015 and its plan implementation date to December 31, 2018 was signed into law on May 14, 2010. The legislation also stipulated that Minnesota Power submit to the Commission and MPCA, beginning by July 1, 2011, a yearly report outlining its emission reduction analysis and potential plans for BEC4. This filing provides the first annual report following the passage of the 2010

[2] One year extensions on both the plan filing and implementation can be obtained with Commission approval. See Minn. Stat. §216B.685, subd. 4(b).
[3] Minnesota Power filed its Boswell 3 Mercury Reduction Plan on October 30, 2006. See Docket No. E-015/M-06-1501.

legislation. Minn. Stat. §216B.6851, subd. 5 which provides for the timing extension and guides annual Minnesota Power report development reads as follows:

> Subd. 5.**Early action; wet scrubbed units.**
>
> (a) The utility electing for regulation under this section shall file an initial plan for mercury emissions reduction at one of its two wet scrubbed units on or before December 31, 2007. The plan must provide for mercury emissions reduction to be implemented at that unit by December 31, 2010. If the plan is approved by the commission, and implemented by the utility, the utility may have until July 1, 2015, to file its plans for reduction at its other wet scrubbed unit at the qualifying facility, and may have until December 31, 2018, to implement mercury emissions reduction at that unit.
>
> (b) Until the utility files its plans for the other wet scrubbed unit, the utility must submit to the commission and agency, by July 1 each year, beginning in 2011, a report containing the following information:
>
> (1) mercury control plans for units subject to this section, including how elements of the plans may affect the performance and cost-effectiveness of emission controls for air pollutants other than mercury;
>
> (2) an assessment of the impacts of federal laws regulating various air pollutants emitted by coal-fired power plants that can reasonably be expected to be enacted by 2018 on the utility's units subject to this section, and potential utility responses to those laws, including, but not limited to:
>
> (i) installing pollution control equipment;
>
> (ii) using pollution allowances to achieve regulatory compliance; and
>
> (iii) retiring or repowering the plant that is the subject of the filing with cleaner fuels considering the costs of complying with state and federal environmental regulations.
>
> For each potential response, the report must include an analysis of the impacts on ratepayers, the utility's financial position, and utility operations, including the impacts on the service life of affected units.
>
> (c) The utility shall consult with the agency, the Department of Commerce, and other interested stakeholders to determine which future federal laws to assess under paragraph (b), clause (2), and the scope of the assessment of the impact of those laws.

Minnesota Power continues to actively monitor and assess progress on the same suite of federal environmental rule makings that raised the Company’s concern to a level that prompted seeking an extension to the mercury reduction plan filing and plan implementation timelines for BEC4 under MERA. Until federal rulemakings on emission reductions that can affect BEC4 are issued, it is difficult to identify the right plan for BEC4 compliance on behalf of Minnesota Power's customers. At the same time, Minnesota Power has been actively studying BEC4 emission reduction alternatives, and particularly investigating mercury removal technologies for BEC4, to eventually determine what will be the optimal equipment to install on the Unit. Most notably, and unlike BEC3, which received a new wet scrubber and fabric filter during its recent emission reduction retrofit, BEC4 has an existing wet scrubber that it is not timely to replace. Emission reduction dynamics on BEC4 are more challenging than those in BEC3 due to this existing wet particulate and sulfur dioxide removal scrubber as this report will discuss. Given the wet scrubber challenges unique to BEC4, Minnesota Power is using the BEC4 retrofit postponement flexibility to investigate and test mercury emission reduction technology for the unique set of circumstances on BEC4, while actively monitoring certain federal rule makings that could affect BEC4 as they progress to final rules.

It should be noted that there will be significant ongoing reporting about the status of BEC4 technology and federal emission rule impacts by Minnesota Power both under the MERA statute and under Minnesota Power's resource plan filings. By February 6, 2012 Minnesota Power will be submitting a Baseload Diversification Study[4] which is a report required by the Commission as a result of Minnesota Power's most recent Resource Plan Order. Among other subjects, the Baseload Diversification Study will include an analysis that discusses Minnesota Power's latest assessment of emission reduction options for BEC4 in light of further information Minnesota Power expects to have between now and then on pending federal emission reduction rules and BEC4 estimated project costs. Minnesota Power will also submit 2012 and 2013 Mercury Emission Reduction Plan Reports by July 1, 2012 and July 1, 2013, respectively. Additionally, Minnesota Power will be submitting its 2013 Resource Plan by July 1, 2013.[5]

[4] Minnesota Power is required to file a study addressing baseload diversification away from coal generation no later than nine months from the May 6, 2011 Order date in Minnesota Power's 2010 Resource Plan docket. See Docket No. E015/RP-09-1088.

[5] Recently, the Department contacted Minnesota Power about participation in an emission reduction modeling exercise that the Department and MPCA plan to participate in with the EPA with regard to Minnesota utility air emissions. The Department asked Minnesota Power to participate in the exercise as one of several stakeholders. Minnesota Power has agreed and assumes BEC4 emission reduction considerations will be a subject in this initiative.

Assuming a plan for BEC4 emission reduction is still undetermined, through these subsequent filings, Minnesota Power will provide the latest information and update on its plan for mercury and other emission reduction at BEC4 to the Commission, MPCA and other stakeholders.

It may also be noted that in August 2008, Minnesota Power received a Notice of Violation (“NOV") from the United States Environmental Protection Agency (“EPA”) asserting violations of the New Source Review (“NSR”) requirements of the Clean Air Act at BEC Units 1-4. The NOV asserts that certain projects undertaken at the Boswell facility between 1981 and 2000 should have been reviewed under the NSR requirements, and that the BEC4 Title V permit[6] was violated. Minnesota Power believes the projects identified in the NOV were in full compliance with the Clean Air Act, NSR requirements and applicable permits. Minnesota Power is engaged in discussions with the EPA regarding resolution of these matters, but it is unable to predict the outcome of these discussions and therefore their effect on BEC4.

II. PROCEDURAL SECTION

A. General Filing Information

Pursuant to Minn. Rule 7829.1300, Minnesota Power provides the following required general filing information.

1. **Summary of Filing (Minn. Rule 7829.1300, subp.1)**

   A one-paragraph summary accompanies this Report.

2. **Service on Other Parties (Minn. Rule 7829.1300, subp. 2)**

Pursuant to Minn. Stat. §216.17, subd. 3 and Minn. Rules 7829.1300, subp. 2, Minnesota Power eFiles the Report on the Department and the Residential Utilities Division of the Office of Attorney General. A summary of the filing prepared in accordance with Minn. Rules 7829.1300, subp. 1 is being served on Minnesota Power’s general service list. In addition, pursuant to Minn. Stat. §216B.6851, subd. 5(b), Minnesota Power serves this Report on the Minnesota Pollution Control Agency.

[6] The Title V permit is the operating permit issued to the facility pursuant to Title V of the Clean Air Act.

3. Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 4(A))

Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722 – 2641

4. Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 4(B))

David R. Moeller
Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 723 – 3963
dmoeller@allete.com

5. Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 4(C))

This Report is being filed on June 30, 2011. There is no effective date or proposed rate change.

6. Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 4(D))

This Report is made pursuant to Minn. Stat. §216B.6851, subd. 5 that requires an annual filing by July 1 of each year until Minnesota Power files its plans for Boswell Unit 4. Minnesota Power's Report falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11 and 7829.1400, subp. 1 and 4 permitting comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed no later than 10 days thereafter.

7. Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 4(E))

Lori Hoyum
Policy Manager
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3601

lhoyum@mnpower.com

8. Impact on Rates and Services (Minn. Rule 7829.1300, subp. 4(F))

This filing will have no effect on Minnesota Power's base rates. However, as discussed in this Report, Minnesota Power will need to seek to include in a future rider or base rates the costs to retrofit BEC4 for emission reduction. Minnesota Power provides anticipated cost ranges for BEC4 retrofits in Section VII.

9. Service List (Minn. Rule 7829.0700)

David R. Moeller
Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 723 - 3963
dmoeller@allete.com

Lori Hoyum
Policy Manager
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355 - 3601
lhoyum@mnpower.com

B. Statutory Compliance Reference List

In order to clearly identify the location of Minnesota Power's information in response to the statutory requirements for this filing, identification of the section(s) that contain the required information is noted as follows:

- Minnesota Power's mercury control plans for units subject to this section, including how elements of the plans may affect the performance and cost-effectiveness of emission controls for air pollutants other than mercury

  See Sections:

  - IV. Boswell Energy Center Unit 4 (see page 16)
  - V. Planning and Analysis Overview (see page 19)

- Our assessment of the impacts of federal laws regulating various air pollutants emitted by coal-fired power plants that can reasonably be expected to be enacted by 2018 on the utility's units subject to this section, and potential utility responses to those laws, including, but not limited to:

  (i) installing pollution control equipment;

  See Section:

- III. Environmental Consideration (see page 10)

(ii) using pollution allowances to achieve regulatory compliance; and

See Section:

- VI. Other Related Compliance Considerations (see page 25)

(iii) retiring or repowering the plant that is the subject of the filing with cleaner fuels considering the costs of complying with state and federal environmental regulations.

See Section:

- VI. Other Related Compliance Considerations (see page 25)

For each potential response, the report must include an analysis of the impacts on:

- ratepayers,

  See Section:

  - VII. Plan Impact on Customers, Finance and Operations (see page 28)

- the utility's financial position

  See Section:

  - VII. Plan Impact on Customers, Finance and Operations (see page 28)

- utility operations, including the impacts on the service life of affected units.

  See Section:

  - VII. Plan Impact on Customers, Finance and Operations (see page 28)

- The utility shall consult with the agency, the Department of Commerce, and other interested stakeholders to determine which future federal laws to assess and the scope of the assessment of the impact of those laws.

  See Sections:

  - II. Procedural Section (see page 5)
  - III. Environmental Consideration (see page 10)

C. Stakeholder Consultation

The 2011 Mercury Emission Reduction Plan Report for Minnesota Power's BEC4 is the first Report filed under the 2010 MERA statute modification and as such provides a baseline picture of the facility, the federal rules that may affect it, and the emission reduction technology alternatives currently being considered. The Report also serves to initiate the ongoing dialogue that will take place with Minnesota Power's stakeholders about BEC4 emission reduction alternatives, costs, and other considerations until a plan for BEC4 is determined. In fact, Minnesota Power consulted with the MPCA, the Department, the Minnesota Center for Environmental Advocacy ("MCEA"), the Izaak Walton League and the Large Power Interveners ("LPI") on a draft of this Report to obtain their feedback prior to filing as required under Minn. Stat. §216B.6851, subd. 5(c). This feedback was used to modify the Report where applicable and used in follow up communications with stakeholders on the comments they made.

Relative to stakeholders providing input on plans for BEC4 emission reduction it should also be noted that, on February 6, 2012, Minnesota Power will be submitting its Baseload Diversification Study to the Commission as required in its most recent Resource Plan Order. The Baseload Diversification Study will include an evaluation of BEC4 with regard to emission reduction plans and technologies, as well as various evaluations and analyses of Minnesota Power's other generating facilities. Thus, the Baseload Diversification Study, in effect, will provide a subsequent analysis of BEC4's status with regard to emission reduction technology and federal rulemaking about six months prior to the next annual report due under the MERA by July 1, 2012. Minnesota Power will consult with stakeholders during the Baseload Diversification Study development process prior to the February 6, 2012 filing about the various aspects of the study including BEC4 considerations.[7] This means stakeholders will have an opportunity to see and comment on a subsequent analysis of BEC4 emission reduction technology, cost and plans via the Baseload Diversification Study within less than six months of this Report being filed. The Baseload Diversification Study stakeholder discussion will help to continue the dialogue process with stakeholders in preparation for Minnesota Power's July 2012 Mercury Reduction Plan Report for BEC4. By July 1, 2013, Minnesota Power's 2013 Mercury Reduction Plan Report for BEC4, and its 2013 Integrated Resource Plan are both due to the Commission. Assuming no definitive plan for BEC4 is determined in the interim, Minnesota Power anticipates that, with the filing requirements it has in 2012 and 2013 that will involve BEC4, on-going, continuous dialogue will occur with its stakeholders as to its environmental

[7] Presently, Minnesota Power has communicated with stakeholders about possible dates in September 2011 for a meeting to obtain their input on the February 2012 Baseload Diversification Study.

plans surrounding mercury emission reduction and other pending environmental regulation as they affect BEC4.

III. ENVIRONMENTAL CONSIDERATIONS

Assessment of Likely Federal Laws to Be Enacted by 2019

Minnesota Power is closely following eight pending federal rulemakings regulating air and water emissions and solid waste from coal-fired power plants that may be enacted by 2019. These regulations could impact BEC4. In compliance with Minn. Stat. §216B.6851, subd. 5(c), Minnesota Power consulted with the MPCA, the Department, MCEA, Izaak Walton League and LPI regarding the rulemakings that may affect BEC4 for their input as this filing was being prepared. These stakeholders did not identify any additional rulemakings Minnesota Power should assess relative to BEC4. In the following paragraphs, Minnesota Power describes the rulemakings it is following relative to BEC4 and its current assessment of their applicability to BEC4.

Transport Rule

On July 6, 2010, the Environmental Protection Agency ("EPA") proposed the "Transport Rule" which requires 31 states, including Minnesota, to reduce power plant sulfur dioxide ("SO_2") and oxides of nitrogen ("NO_x") emissions that can significantly contribute to ozone and fine particle pollution problems in other states. The final rule is expected in July 2011. Projected requirements for Minnesota in Phase 1 suggest that the significant emission reduction measures taken by Minnesota Power on its various units since 2005 will be sufficient to comply with estimated Transport Rule SO_2 and NO_x requirements. Consequently, at this time, Minnesota Power does not expect the Transport Rule to affect BEC4.

National Ambient Air Quality Standards

National Ambient Air Quality Standards ("NAAQS") are established to protect human health ("primary standards") or public welfare ("secondary standards"). EPA has recently revised or is proposing revisions to four NAAQS, as described below.

- *Ozone NAAQS.* The EPA is proposing to more stringently control emissions that contribute to ground level ozone. In January 2010, the EPA proposed to reduce the primary ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA expects to issue final standards by July 2011. As proposed, states have until early 2014 to submit plans outlining how they will meet the standards.

- *Fine Particulate Matter NAAQS.* The EPA finalized the NAAQS Fine Particulate Matter ("$PM_{2.5}$") standards in September 2006. The United States D.C. Circuit Court of Appeals has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA plans to finalize the new $PM_{2.5}$ standards in 2011 and state attainment status determination will likely not occur prior to 2013. As early as late 2014, affected sources would have to take additional control measures if modeling demonstrates non-compliance at the property boundary.
- *SO_2 and NO_2 NAAQS.* The EPA recently finalized a new one-hour NAAQS for SO_2 and nitrogen dioxide ("NO_2"). Monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. It is unclear what the outcome of this evaluation will be. These NAAQS could also result in more stringent emission limits on Minnesota Power's steam generating facilities, possibly resulting in additional control measures on some of its units. Compliance with these new NAAQS is expected to be required as early as 2017.

NAAQS can impact BEC4 in two possible ways. First, if air dispersion modeling demonstrates that the NAAQS are being exceeded at the overall Boswell facility property boundary, Minnesota Power would have to take measures to reduce emissions, which may mean a reduction in SO_2, NO_x or particulate matter ("PM") from the BEC4 air emission stack depending on which standards are being exceeded.

Second, if a county which contains one of Minnesota Power's facilities goes into non-attainment, then existing facilities may have to install Reasonably Achievable Control Technology ("RACT") to control emissions. At present, Minnesota Power has not concluded whether the existing controls on BEC4 would meet RACT.

National Emissions Standards for Hazardous Air Pollutants

On March 16, 2011, the EPA issued a proposed Rule, National Emissions Standards for Hazardous Air Pollutants ("NESHAP") that would reduce emissions of hazardous air pollutants from coal- and oil-fired electric utility steam generating units ("EGUs"). The proposed NESHAP establishes Maximum Achievable Control Technology ("MACT") standards for various trace metals, including mercury ("Hg"), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride ("HCl") and hydrogen fluoride ("HF"). A particulate matter emission limit is proposed, as a surrogate for trace metals other than mercury. The impact of the proposed rule on BEC4 is being evaluated at this time. Based on initial review of the proposed emission limits, BEC4 would be required to install mercury controls, and also achieve a lower particulate matter emission rate than it is currently able to achieve. The final NESHAP Rule is expected to be released in November 2011, with compliance due by 2015 or 2016. It is not known at this time whether the proposed emission limits will be adjusted in the final Rule, and whether the proposed timeline will be adhered to. For example, adjustments to the emission limits, averaging periods, compliance determination methods and facility averaging capability could occur based on the comments EPA receives on the proposed Rule. These adjustments may be significant enough to drive the ultimate technology solutions that are most prudent for BEC4 to achieve compliance, thus Minnesota Power cannot specify its technology solution for mercury emission reduction on BEC4 at this time. Also, Section 112(i)(3)(b) and 112(i)(4) of the Clean Air Act allow for EPA and/or the President to extend the compliance deadline, so the final compliance date is uncertain at this time.

Clean Air Visibility Rule

The federal Clean Air Visibility Rule requires states to submit state implementation plans ("SIPs") to the EPA to address regional haze visibility impairment in federally-protected parks and wilderness areas. In December, 2009, Minnesota submitted its SIP to EPA for approval. EPA has not yet acted on that submittal. Depending on when EPA acts on the state SIP, implementation could be required as early as the 2015-2016 timeframe. The SIP did not include any requirements for further emission reductions for SO_2 and NO_x (which contribute to haze) on BEC4 because BEC4 was not BART (Best Available Retrofit Technology) eligible under the

Clean Air Visibility Rule. As a result, Minnesota Power is not anticipating that the Clean Air Visibility Rule will affect BEC4.

Regulation of Greenhouse Gases

On May 13, 2010, the EPA issued the final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule ("Tailoring Rule"). The Tailoring Rule establishes permitting thresholds required to address greenhouse gas emissions for new facilities, at existing facilities that undergo major modifications, and at other facilities characterized as major sources under the Clean Air Act's Title V program. If provisions of the Tailoring Rule are triggered by a generator, EPA has indicated that they are formulating operational efficiency requirements as a means for containing or reducing carbon dioxide ("CO_2") emissions. Minnesota Power does not anticipate that BEC4 will be subject to requirements under these provisions, since no major modifications that would result in a significant emissions increase (greater than 75,000 tons CO_2 per year) are planned by Minnesota Power for BEC4 by 2019.

Regulation of Coal Combustion Residuals

On June 18, 2010, the EPA proposed regulations for coal combustion residuals ("CCR" or "coal ash") generated by the electric utility sector. The proposal sought comments on three general regulatory approaches for coal ash including: regulation as a hazardous waste under Subtitle C of the Resource Conservation and Recovery Act ("RCRA"); regulation under Subtitle D of RCRA as a non-hazardous waste; and regulation under Subtitle D of RCRA, but only at the end of a current ash storage facilities (i.e., impoundment or landfill) useful life (so-called "D-Prime" option). Minnesota Power generates coal ash at Boswell Energy Center, including fly ash and bottom ash from BEC4, that is currently managed in onsite impoundments (ash ponds). Minnesota Power anticipates the CCR rule would affect ash storage at the Boswell facility and thus BEC4 would be impacted. It is now estimated that the final rule will be published in late-2012 or early 2013. Impacts to BEC4, if any, from an eventual final rule would likely occur beginning about 2018.

Should one of the three general regulatory approaches for coal ash that are out for comment be adopted in EPA's final Rule, the impact could be significant on the Boswell facility, and thus BEC4, if conversion to a dry ash storage facility is required. The "D-Prime" option would have the least economic impact though, even with "D-Prime", Minnesota Power would be looking at an estimated several hundred million dollars of cost to comply. Minnesota Power is very concerned about the potential impact of this cost burden on customer rates especially as it is entirely unnecessary given the state of Boswell's ash ponds. The ponds at Boswell are already robust, well built, and well managed. They utilize clay-lined designs and for decades have protected public health and welfare. The ponds are regulated under the Minnesota Department of Natural Resources and were found to be in good order in the most recent inspection conducted by the EPA in 2010. While Minnesota Power is vigorously opposing the proposed CCR Rule because its existing ponds are robust and any investment required through CCR is unjustified, the outcome of the Rule is still pending and thus its potential impacts on BEC4 decision making are unknown.

Regulation of Water Effluent

On September 15, 2009, the EPA announced its decision to proceed with information collection and advanced rulemaking to revise regulations of wastewater discharges from power plants and the treatment technologies available to reduce pollutant discharges (40 CFR 423). EPA plans to propose a rulemaking for the steam electric power generating industry in July 2012 and take final action by January 2014.

The Boswell Energy Center ash storage area is comprised of both wet and dry handling and storage methods. BEC4 captures particulates, mercury and sulfur dioxide in its wet scrubber and the resulting ash slurry is currently discharged into the BEC4 ash pond for ash/water separation and ultimate ash storage. The BEC4 pond is currently a closed-loop system; however, after extensive recycling, and as ash pond capacity is reduced, the final remaining wastewater in the BEC4 pond will ultimately need to be dewatered prior to any closure or repurposing of that pond.

Operational dewatering of the pond to BEC4 will likely be subject to future EPA effluent guidelines. The wastewater created at BEC4 and discharged into the Mississippi River will be treated to meet all applicable water quality standards. Future wastewater treatment will be provided using one or a combination of the following systems: 1) the existing central wastewater treatment facility ("CWWTF"), 2) the existing CWWTF with appropriate modifications to provide additional treatment capabilities and/ or 3) a portable treatment system provided by an outside vendor. Until the final rule is issued, the impacts of the water effluent rulemaking on BEC4 cannot be determined.

Bottom ash from BEC4 is currently discharged to the Units 1-4 Bottom Ash Pond. After gravitational clarification, the bottom ash contact waters from Unit 1-4 are routed to the central wastewater facility for treatment prior to discharge to the Mississippi River. The effluent guidelines rulemaking may also impact this BEC4 discharge.

<u>316b Proposed Rule - Standards to Protect Aquatic Ecosystems</u>

On April 20, 2011, the EPA published a new proposed cooling water intake Rule, commonly known as "316(b)", for existing power plants and manufacturing facilities to be implemented through National Pollutant Discharge Elimination System permits.

Clean Water Act Section 316(b) requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The proposed new rule is aimed at reducing fish impingement and fish entrainment at cooling water systems. Affected facilities will be required to reduce fish impingement by either monitoring to show specified fish and shellfish mortality standards have been met or demonstrating that the intake velocity meets specified design criteria. Entrainment technology determination will rely on state permit writers' best professional judgment, after taking into consideration a suite of site-specific factors. Technologies to meet the impingement requirements will have to be implemented as soon as possible, but no later than *within 8 years* of issuance of the final rule, expected in 2012. Where required on Minnesota Power units, expected impingement technology would likely be installed in the 2014-2016 timeframe, with any required entrainment technology installed in the 2017-2020 timeframe.

Since BEC4 is equipped with a cooling tower system to cool the circulating water, which is considered a best technology available, impacts of the 316(b) rule on BEC4 are expected to be low. Impacts on BEC4 will likely be determined by specifics of the final rule and completion of either field measurement studies and/or engineering assessments.

Until final federal rulemakings for various air pollutants, solid ash disposal, water effluent considerations and cooling water intake structures that can affect BEC4 are known, it is difficult to identify the right plan for BEC4 compliance on behalf of Minnesota Power's customers. While Minnesota Power is actively monitoring and assessing federal rulemaking and studying potential BEC4 emission reduction technologies, multiple rulemaking unknowns exist and will significantly impact the solution(s) ultimately selected for emission reduction compliance on BEC4. Basing plans on adequate information concerning rules as well as current and emerging emission reduction technology will help Minnesota Power ensure capital investments at BEC4 are optimal for customers overall in terms of performance and cost.

IV. BOSWELL ENERGY CENTER UNIT 4

BEC4 is located in Cohasset, Minnesota and was placed in service in 1980.[8] BEC4 is a tangentially-fired steam generator burning low mercury, low sulfur Montana Powder River Basin ("PRB") coal. Until recently, BEC4 operated with a gross generation capability of 585MW, though only 535MW have been available as net output due to 50MW of existing station service required to operate auxiliary equipment. In 2010, Minnesota Power replaced the original turbine with a more efficient design that is able to operate at over 635 Gross MW or 585 Net MW without increasing the steam flow or amount of fuel consumed. Turbine upgrades to increase generating output on existing generating units which do not require additional fuel are one of the most cost-effective means for increasing Minnesota Power's reliable energy supply without increasing criteria pollutant emissions. In essence, Minnesota Power added 60MW of zero emission capacity and energy as a result of this efficiency improvement project.

Minnesota Power has burned Montana PRB coal on BEC4 since it was placed in service in 1980. In fact, BEC4's boiler was specifically designed to burn this fuel. Beginning in January

[8] Since 1990, WPPI Energy (formerly Wisconsin Public Power, Inc.) has owned 20% of the output from Boswell Unit 4. Docket No. E015/PA-90-153.

2011, Minnesota Power began burning a blend of coal from Wyoming and Montana at Boswell and, beginning in 2012, will likely utilize a greater percentage of Wyoming PRB coal to fuel Boswell's units including BEC4. This switch in coal source is primarily due to expiring contracts with Minnesota Power's current fuel providers, as well as the fact that the coal seams in Montana are increasing in sulfur and ash content, making them a less environmentally desirable fuel source. Coals, in general, can appear very similar, yet have very different combustion characteristics due to trace element differences in each type. Minnesota Power has prepared for the Wyoming PRB fuel change at BEC4 over a several year period by putting significant effort into determining which mines provide a coal quality that is compatible with the existing boiler design, while minimizing cost and emission impacts. Computer modeling and actual test burns of the fuel were conducted on BEC4. In these test burns, emissions, flue gas and steam temperatures, ash build up on the tubes (boiler fouling), combustion characteristics, cost, and many other factors were evaluated in determining what fuel blend is best suited to BEC4.

Existing Emission Control Equipment

BEC4 emissions are currently well controlled. BEC4 was originally constructed with first generation Low NO_x Burners and Close Coupled Over Fire Air[9] and a then state-of-the-art wet spray tower absorber/particulate removal system. This system removes more than 85 percent of the SO_2 and over 97.5 percent of PM. Investments made in emission reduction technology over the past few years have resulted in continued improvements in emission reduction at BEC4.

<u>NOx Control</u>

In late 2008, Minnesota Power installed Selective Non-Catalytic Reduction ("SNCR") technology for the removal of NO_x at BEC4. The SNCR system utilizes NALCO Mobotec's

[9] Close coupled over-fire air ("CCOFA") is a type of over-fire air system used for NOx emission reduction. CCOFA systems are typically implemented by adding air injectors immediately above the existing furnace burners. This was an early technology used for NOx control. As technology improved, they found it worked better to stage the flame even farther by adding the over fire air even higher in the boiler. The staging of the combustion air lowers the flame temperature and since NOx is formed in higher temperatures, less NOx is formed.

Rotamix technology. Fourteen boiler injection ports are used to deliver urea[10] into the boiler to chemically transform NO_x emissions into harmless nitrogen gas and water vapor. In 2010, Minnesota Power further increased its effectiveness in preventing the formation of NO_x with the replacement of the first generation low NO_x burners with new state-of-the-art Low NO_x Burners and Separated Over Fire Air technology. In combination, these NO_x controls provide, on average, approximately a 55 percent annual reduction in NO_x emissions.

Low NO_x Burners with Over Fire Air ("LNB/OFA") is a widely-used technology for coal-fired utility boilers aimed at minimizing the creation of NO_x in the coal combustion process. LNB/OFA limits NO_x formation by controlling the stoichiometry and temperature profiles in each burner zone. The unique design features of low NO_x burners create a reduced oxygen level in the combustion zone that limits fuel NO_x formation, a reduced flame temperature that limits thermal NO_x formation, and/or a reduced residence time at peak temperature which also limits thermal NO_x formation. Additionally, the installation of LNB/OFA significantly reduces the amount of urea required for the SNCR technology.

<u>PM and SO_2 Control</u>

BEC4 currently utilizes a wet venturi scrubber for PM control and a spray tower absorber for SO_2 control referred to as wet flue gas desulfurization ("WFGD"). A small portion of the flue gas (approximately five percent) bypasses the venturi spray tower absorber and WFGD. This bypass stream is effectively treated by an electrostatic precipitator for PM control before being blended with the remainder of the flue gas, where it acts to reheat the flue gas treated by the venturi spray tower absorber and WFGD. This process results in keeping the flue gas dry as it exits the WFGD and passes through the induced draft (ID) fans, duct work, and finally through the stack. Dry flue gas is critical because moist gas is highly corrosive and would corrode the fans, ductwork, and soften the mortar within the stack. New units with WFGD are designed for

[10] In most commercial SNCR systems, either ammonia or urea is used as the reagent. A reagent is a substance used in a chemical reaction to detect, measure, examine, or produce other substances. Ammonia may be injected in either anhydrous or aqueous form, and urea, as an aqueous solution.

such operation. The fans are positioned before the WFGD and the ductwork is lined with a corrosion resistant alloy. The stack is also specially designed with corrosion resistant linings to withstand the corrosive nature of the wet flue gas.

V. PLANNING AND ANALYSIS OVERVIEW

Engineering Studies

Understanding the need to make prudent investments on behalf of Minnesota Power's customers, and realizing finalization of federal environmental rules for criteria pollutants, in addition to mercury, is still pending, Minnesota Power must proceed strategically and thoughtfully when determining the appropriate action for BEC4 compliance with MERA. Every effort must be taken to ensure investments in emission reduction equipment for any criteria pollutants on any of Minnesota Power's generating plants, including BEC4, are utilized to the fullest extent of their useful life. Minnesota Power has studied and continues to analyze many options for meeting environmental regulations on BEC4 and its other units including those for mercury, NO_x, SO_2 and PM. It is important to recognize that the best alternative for any one pollutant may not provide the best overall solution for meeting other pollutant control requirements. Overall, the goal in multi emission reduction is to cost-effectively optimize the reductions for all pollutants in total.

Minnesota Power continues to research options for a multi-pollutant solution for BEC4 that include refurbishment of its existing components as well as replacement of the existing spray tower absorber with a state of the art design. Both conventional WFGD, as well as various semi-dry technologies, are being studied. Historically, the semi-dry technologies have not achieved the same emission removal rates as are realized with WFGD technologies; however, advancements in the semi-dry technologies have moved the capture levels to those attained with WFGD technologies. Semi-dry technologies are most effective when burning low sulfur fuels of the type utilized at BEC4.

In reviewing options that have the potential to produce a 90 percent mercury removal rate at BEC4, Minnesota Power studied the use of a fabric filter with activated carbon injection as that combination appeared to provide the most promise of achieving a 90 percent reduction in mercury emissions. The study results indicated, however, that installation of this equipment would compromise performance of the existing BEC4 absorber towers used for SO_2 removal. The alkaline fly ash that is currently captured in the venturi section and subsequently utilized in the absorber towers for SO_2 emission reduction on BEC4 would no longer be available once a fabric filter is added for particulate and mercury control.[11] An attempt to wet the ash captured by the fabric filter was not considered because using wet ash in the spray tower absorber could result in re-emission of the mercury that was captured in the fabric filter by the activated carbon.

In 2007, Minnesota Power contracted with the engineering firm Burns & McDonnell to conduct a feasibility study to look at the options available to reduce NO_x, SO_2, PM, and mercury at BEC4. Based on the results of the initial study, Minnesota Power again contracted with Burns & McDonnell in 2008 to conduct a cost estimate study of the most promising available emission reduction options for BEC4. The 2008 study provided more detail and insight on available options for retrofitting the existing environmental controls on BEC4. Burns and McDonnell's study confirmed that potential control technologies applied to BEC4 must be analyzed as an overall system to determine the cost per pollutant reduced. With emission reduction retrofits generally there is a substantial co-benefit between the pollutants that are captured by each technology, and thus it is important to understand how the technologies will work together in order to optimize their selection.

In 2009, Minnesota Power contracted with the engineering firm Black & Veatch to obtain a second opinion of available options and costs associated with an environmental retrofit on BEC4. The results identified very similar costs to the earlier Burns and McDonnell study. However, Black & Veatch identified a new emission reduction option, that of utilizing a Circulating Dry Spray tower absorber ("CDS") for the removal of SO_2. In a CDS, flue gas enters a vertical reactor tower before exiting to a fabric filter where additional emission capture and collection takes place. Flue gas enters at the base of the vertical reactor tower and flows upward through a short tube called a venturi. Flue gas passing through the venturi mixes with the

[11] For SO_2 removal, the alkaline fly ash is used as an effective replacement for lime which is typically used to remove SO_2 in a wet scrubbing system. If a fabric filter is required the fly ash would no longer be available and a lime/limestone system would have to be added.

fluidized bed[12] which is comprised of a mixture of dry lime and fly ash and re-circulated by-product (fly ash) from the fabric filter. The intensive gas-solid mixing occurring at this point in the CDS process promotes reaction of sulfur oxides in the flue gas with the dry lime particles. Water spray is introduced separately above the venturi section for flue gas humidification to enhance the reactivity of the lime and physical absorption for more effective SO_2 removal. Activated carbon is injected into the vertical reactor tower for the purpose of capturing mercury and is collected along with the PM in the fabric filter. Introducing the activated carbon prior to the flue gas entering the fabric filter allows for the necessary reaction time to maximize mercury removal.

Mercury Emission Reduction Technology Testing

Minnesota Power has conducted extensive testing specific to the fuel and unit configurations in its coal generating fleet including most recently mercury reduction technology on BEC4. A rich history of full scale mercury reduction testing dates back to the 1990s when Minnesota Power partnered with Xcel Energy and others to test early halogenated and activated carbon treatment systems at Minnesota Power's Laskin Energy Center. These tests along with others across industry uncovered nuances between elemental and oxidized mercury speciation. The testing built confidence in methods to convert elemental to oxidized mercury and remove resulting oxidized mercury compounds and capture it from flue gas at high removal rates. This aided development of what are now traditional mercury control technologies for coal-fired power plants which utilize a combination of activated carbon injection to absorb the mercury and a particulate control device such as a fabric filter to collect the particulate and captured mercury.

BEC4 is unique in that it utilizes a combination wet particulate removal and sulfur dioxide removal device that has not required a fabric filter or electrostatic precipitator as found in other similar sized coal-fired generating units. Therefore, the implementation of a traditional mercury reduction strategy on BEC4 would require a significant investment to install a fabric filter. Adding to the expense of installing a fabric filter, the current operation of the BEC4 wet spray tower absorber would require significant upgrades to account for the loss of fly ash alkali.

[12] A fluidized bed is a layer of small solid particles suspended and kept in motion by an upward flow of a fluid (as a gas). The fluidized bed acts as a reactor for the flue gas to make contact with the reagent.

In addition, there would be costs for the conversion to limestone handling/delivery and disposal systems. For these reasons, Minnesota Power chose to evaluate other mercury reduction technology options for BEC4, including those of an emergent nature. Due to the significant investment as well as operational changes that would be required to add a fabric filter to BEC4, Minnesota Power continues to monitor and consider mercury emission reduction options for BEC4 with less operational/performance history or that are still currently under development to see if the fabric filter cost can be avoided.

Minnesota Power looked to utility industry technology and equipment provider Alstom as it began a full scale mercury removal testing phase at BEC4. Alstom has demonstrated fairly high percentages of mercury removal in plants that do not have fabric filters when using a combination of their Mer-cure and KNX technologies. The Mer-cure technology consists of activated carbon injection similar to other companies with one major application difference; the activated carbon is ground to ultrafine consistency and injected into the flue gas in the boiler system resulting in greater mercury capture. The KNX process utilizes a calcium bromide solution that is sprayed on the coal before it enters the boiler. The KNX is an oxidant which converts elemental mercury to oxidized mercury, allowing the activated carbon to capture it.

Minnesota Power began the first phase of full scale testing of the Alstom process on BEC4 in May 2009 utilizing a blend of current Montana fuels and potential future Wyoming fuels. Initial results on how Alstom's Mer-cure and KNX technologies interact with BEC4's unique existing emission reduction equipment showed very promising mercury removal levels; however, a number of operating challenges were identified through the testing. Opacity[13] increased with the activated carbon injection. Fine particles found in Wyoming coals can be an opacity compliance concern, as well. Activated carbon injection was reduced in many of the test runs to prevent opacity violations; consequently, the degree of mercury capture Minnesota Power was able to achieve during this testing was limited. Throughout the testing on BEC4, the amount

[13] Opacity is a measurement required by the state as a determination of particulate matter exiting the chimney. BEC4 operating permit requires operation under 20 percent opacity.

of activated carbon injected directly correlated to opacity compliance problems i.e. higher injection rates for any length of time created opacity compliance problems.[14]

The second issue identified was the fact that, as KNX was injected, a bromine gas was created in the spray tower absorber building. The spray tower absorber design at BEC4 utilizes open recycle tanks and a reaction takes place under these conditions that gives off a bromine gas. To protect worker health, entry into the spray tower absorber building was prohibited while the problem was investigated. Additionally, the KNX injection was suspended during some test runs. The bromine gas issue was resolved by covering the recycle tanks and venting them into the absorber tower.

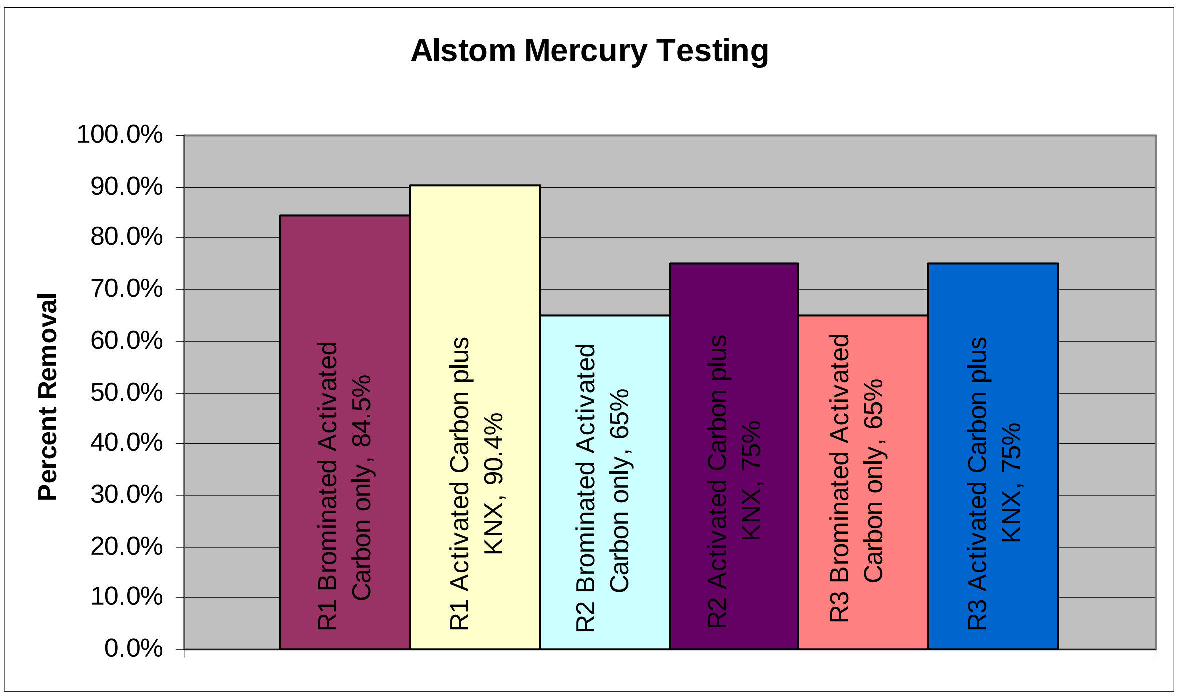
The second phase of testing, conducted in fall of 2009, utilized the existing blend of Montana fuel and was conducted over an extended period to determine sustainable operation on BEC4. The plan included the injection of a brominated activated carbon over a thirty-day test period to determine the amount of mercury reduction achievable while injecting the activated carbon, and while maintaining opacity compliance. The test also indicated what reduction in the injection of the brominated activated carbon would be reasonable on BEC4 without the use of the KNX product that led to the bromine gas concentrations in the spray tower absorber building. At the end of the testing period, the KNX was added at a lower level to determine what sustainable level of mercury removal was possible with KNX. To ensure safety, the recycle tanks were sealed and ventilated to prevent the bromine gas from escaping into the building. Monitoring was done at various points in the spray tower absorber building. There was no bromine gas detected in the building during any future testing which demonstrated that sealing of the tanks was an effective solution.

During the second phase of testing, the opacity increased with the activated carbon injection, as expected, based on the first round of testing. Mercury reduction levels were not as high as demonstrated in the first testing phase. Through this extended second testing period with varying levels and combinations of brominated activated carbon and lower levels of KNX, Minnesota Power learned it cannot sustain injection levels on BEC4 with activated carbon

[14] The fine particles found in Wyoming coal and the ultra fine activate carbon injected to control Hg emissions reduced the PM collection efficiency of the venturi scrubber causing opacity to increase.

injection to reach an 85 percent or higher mercury removal rate due to opacity compliance issues. Sustainable removal rates were in the 60 - 65 percent range with brominated activated carbon and 70 - 75 percent range with the KNX added in addition to the activated carbon. Mercury removal efficiency on BEC4 did not appear to increase with higher injection rates of KNX.

The third phase of testing on BEC4 was conducted in 2010 with a blend of Wyoming coal and the existing blend of Montana fuel. Results were very similar to the second phase of testing. The testing demonstrated short term removal efficiencies peaking in the 85 percent range, however, Minnesota Power was not able to maintain that level of removal on BEC4 over a longer period of time due to opacity issues forcing the activated carbon injection rate to be reduced.



In summary, as a result of the three tests Minnesota Power has conducted regarding mercury removal on BEC4, Minnesota Power found mercury removal efficiencies up to 90 percent could be achieved for very short time periods; however, for longer time periods, 65 to 75 percent would be more realistic and sustainable. For context, it should be noted that the MERA has an explicit preference that mercury removal be as close as possible to 90 percent, so Minnesota Power is diligently investigating possible solutions for BEC4 that would achieve that goal.

Along with an inability to achieve a sustained 90 percent mercury removal rate on BEC4 with technology tested to date, opacity compliance remains an ongoing concern when utilizing the existing wet scrubber for particulate and mercury-related chemical injection materials on BEC4.

VI. OTHER RELATED COMPLIANCE CONSIDERATIONS

Prospective Controls for BEC4 Other Than Those Associated with Mercury Emission Reduction

As discussed in Section III, Minnesota Power is closely following pending federal rules regulating various air pollutants, in addition to mercury, emitted by coal-fired power plants that may be enacted by 2019. Minnesota Power is seeking to avoid decisions that would result in mercury (or any other) emission reduction equipment being installed and then removed prematurely in order to accommodate the subsequent addition of reduction technology for other pollutants. As noted previously, Minnesota Power is also closely following EPA development of the coal combustion residuals, the Section 316(b) fish impingement/entrainment and the steam effluent water rules. By considering other potential environmental reduction beyond mercury, Minnesota Power can ensure the mercury emission reduction investment for BEC4 fits well technically with a multi-emission reduction/environmental improvement installation. The coal combustion residuals rule has the potential to require a large amount of capital investment at Boswell so it is prudent for Minnesota Power to be studying the impact of this rule relative to other emission reduction investment for BEC4. Additionally, the water effluent rule that is pending may require the investment of additional capital in part due to BEC4 operations. Taking the necessary time to conduct a thorough analysis of pending federal rules and current and emerging emission reduction technology for various air pollutants as well as solid ash disposal, Section 316(b) fish impingement and entrainment and water effluent considerations, will help Minnesota Power ensure capital investments at BEC4 are optimal for customers overall in terms of performance and cost.

Prospective Air Emission Rule Impacts Beyond Mercury

The following is a description of other emission reduction equipment[15] that may be involved in an air multi-emission reduction installation on BEC4:

- *Installation of a fabric filter or other enhanced particulate removal equipment.* While Minnesota Power is seeking to avoid the additional investment while still meeting environmental requirements, a fabric filter or other equipment may be required for mercury and other hazardous and/or criteria pollutant removal.
- *A new flue gas desulfurization unit (spray tower absorber) for enhanced SO_2 emission reductions and particulate removal.* The existing scrubber, also referred to as Flue Gas Desulfurization ("FGD"), would have to be modified to operate on lime or limestone or be replaced if a fabric filter is installed for mercury control (see Section V, page 19). The FGD uses fly ash for SO_2 removal. This works simply due to the conditions in the FGD allowing the alkalinity in the ash to react with the SO_2.

Prospective Coal Combustion Residuals Impacts

- *Retrofit of existing ash impoundments.* An eventual federal coal ash rule could require that existing ash ponds be converted from wet to dry systems including those currently utilized by BEC 4.

Prospective Water Effluent Impacts

- Additional wastewater treatment equipment could be required at Boswell for BEC4 and other units to meet future EPA water effluent water quality standards.

Retirement or Repowering of BEC4

As an alternative to installing required additional emission reduction technology on BEC4, the costs, operational impact and other factors associated with retiring or replacing BEC4

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[15] Minnesota Power is not ruling out the possibility that Selective Catalytic Reduction ("SCR") technology for further NO_x emission reductions, beyond those achieved with SNCR, could be installed on BEC4 as a result of the pending federal environmental laws in the 2020 timeframe or beyond. Installation of SCR technology would require a significant capital investment by Minnesota Power.

with cleaner fuels are being evaluated. Replacing BEC4 with a natural gas combined cycle resource is an alternative to installing new emission controls through 2019, since natural gas generation results in emission of less mercury, SO_2, PM and other pollutants to an extent comparable to coal unit emission control retrofit equipment. Natural gas, however, is currently at a significant price premium relative to coal for the equivalent energy content. Based on NYMEX Natural Gas Futures on June 23, 2011 and public information available at http://www.eia.gov, natural gas prices on a $/mmbtu basis at the Henry Hub in Louisiana are expected to be two to four times the delivered price of either Western Montana or Wyoming Powder River Basin coal on a $/mmbtu basis through 2023. Determining the prudency of replacing BEC4 with natural gas involves assessment of an array of resource planning alternatives, including natural gas supply and price analysis and comparison with other electricity supply options. The majority of Minnesota Power’s total energy supply is used by globally competitive industrial customers. Over half of the electricity Minnesota Power sells to retail customers is purchased by its 12 largest industrial customers which are also the region’s major employers Their economic viability as well as rate impacts on all customers are key considerations in Minnesota Power resource supply decisions. Any replacement evaluation Minnesota Power makes also must consider the fact that BEC4 is a joint-owned unit with WPPI Energy, a 20 percent owner of BEC4. Minnesota Power will be analyzing retirement and replacement of its coal-fired generating units, including BEC4, as part of its Baseload Diversification Study to be submitted to the Commission in early 2012.

Using Pollution Allowances to Achieve BEC4 Regulatory Compliance

Under the federal acid rain program, SO_2 emission allowances are already required to support Minnesota Power’s regulatory compliance. No new provisions are anticipated through 2019 that would impact Minnesota Power’s allowance use for acid rain. Minnesota Power has, and will continue to have a surplus of allocated allowances to cover its SO_2 emissions under this program.

NO_x and SO_2 allowances are expected to be required to support compliance with the Transport Rule beginning in as early as 2012. Based on the proposed Rule, Minnesota Power anticipates an allocation of allowances that will more than offset its annual SO_2 and NO_x emissions, which would eliminate the requirement to purchase allowances to cover emissions.

Based on its surveillance of carbon emission reduction policy making, Minnesota Power is not anticipating that CO_2 emission related allowances will be required before 2019. Notably, Congressional leadership in 2010 indicated that Waxman-Markey style cap and trade program legislation will not be enacted and the focus on a cap and trade solution for carbon policy has diminished. Rather, measures that provide for improved operating efficiency, conservation and use of renewable energy seem to be the new point of emphasis relative to carbon reduction and are being considered. These types of measures are not expected to directly impact existing coal unit operations such as those at BEC4.[16]

The proposed NESHAP does not provide for allowance trading. There is a provision in the pending NESHAP rule that would allow site averaging but generally NESHAP will require equipment installation.

In conclusion, at this time Minnesota Power does not anticipate that emission allowance use will play a significant role in BEC4 air emission compliance.

VII. PLAN IMPACT ON CUSTOMERS, FINANCES AND OPERATIONS

Impact to Customers

Based on preliminary planning and analysis, Minnesota Power projects a low end to high end range of $400-750 million of capital cost to comply with current and expected air emission reduction mandates that affect BEC4. The ultimate cost depends on final rules, technology and other project specific factors. The MERA is the only absolute emission reduction requirement on BEC4 at this time. Using a $400-$750 million range, Minnesota Power projects overall customer rate increases to span somewhere between 15 percent and 25 percent. Minnesota Power will be able to refine the cost ranges and customer rate increase percentages as final rulings are issued on pending federal environmental regulations and specific technology

[16] It should be noted that, from a plant efficiency standpoint, that a new turbine rotor was installed on BEC4 in 2010. This turbine rotor provides approximately 60MW of additional energy with no additional fuel or emissions.

solutions are selected, including equipment and erectors' scope and costs for fully designed projects.

Financial Impact to the Company

Minn. Stat. §216B.683, in addition to Minn. Stat. §216B.1692, provides the ability for Minnesota Power to seek approval for current cost recovery of investments and expenditures related to compliance with MERA through an emission-reduction rate rider. The benefit of current cost recovery is that it better positions a public utility such as Minnesota Power financially to make the necessary investments and expenditures to comply with its statutory mandates. Thus, the Company has determined it should be able to secure the necessary financings for an emission reduction project with total project costs that fall within the low end to high range of $400 – 750 million assuming current recovery through a rider.

Utility Operations Impact

Minnesota Power operates various coal-fired generating units with varying types of emission reduction technology. Some of this technology is original to the generating unit, while other technologies are new and state-of-the-art. At BEC, Minnesota Power utilizes fabric filters for PM on Units 1, 2, and 3. Minnesota Power also utilizes LNB/OFA on all four generating units. Additionally, BEC3 utilizes a SCR for Best Available Control Technology level NO_x removal. For SO_2 control, BEC3 utilizes a state of the art absorber tower and BEC4 employs an older technology absorber tower. SNCR technology is utilized on BEC Units 1, 2 and 4. Over the past several years, Minnesota Power has installed numerous emission control systems on all but one of its coal generating facilities, including those installed at BEC 4. Minnesota Power's experience with constructing and operating emission reduction technologies has prepared its skilled staff well for the installation and operation of future emission reduction investments, whether they are existing or new technologies.

There is a high degree of complexity in operating and managing a large generating unit such as BEC4 today, given the variability of the MISO energy market, fuel quality and supply, customer demands and rapidly evolving external bulk electric system operations and environmental regulations. Minnesota Power must prudently consider all of these factors in aggregate when determining the optimum path forward at BEC4. Assuming federal regulatory clarity and based on preliminary planning and analysis to date, Minnesota Power does not anticipate any significant ongoing operational issues as the result of installing any of the technology being studied at this time.

Service Life Impact

Once actionable outcomes from pending federal rulemaking are known, Minnesota Power will identify the appropriate emission reduction plan and speak to any impact on the service life of BEC4. Currently, there are no planned retirements or changes to BEC4 service life, as outlined in Minnesota Power's most recent annual remaining life depreciation filing.[17] As Minnesota Power determines the optimal path forward at BEC 4, any changes in service life will be reflected in its future annual remaining life depreciation filings.

VIII. SUMMARY

Minnesota Power continues to actively monitor and assess federal rule making for outcomes that could affect BEC4 and its other units. It also continues to simultaneously study emission reduction technology options for BEC4 that could optimize emission reduction through prudent investment. Based on its engineering analysis and the status of federal rules, Minnesota Power needs more information to make a sound decision about BEC4 emission reduction investment including that for mercury. Until the various rules that will affect BEC4 are known and understood, it is difficult for Minnesota Power to identify the right plan for BEC4 MERA compliance that will balance operational needs, cost effectiveness and emission reduction on behalf of its customers.

There will be ongoing reporting about the status of BEC4 technology and federal emission rule impacts by Minnesota Power under the MERA statute and under Minnesota Power's resource planning filings until Minnesota Power identifies a definite plan for BEC4 that it can propose to the Commission and other stakeholders as optimal for customers. By February 6, 2012 Minnesota Power will be submitting a Baseload Diversification Study which is a report ordered by the Commission as a result of Minnesota Power's most recent resource plan filing.

[17] See Docket No. E015/D-11-327 for Minnesota Power's 2011 Remaining Life Depreciation Petition.

The Baseload Diversification Study will include an analysis of BEC4 that will discuss Minnesota Power's latest assessment of emission reduction options for BEC4 in light of further information Minnesota Power obtains regarding pending federal emission reduction rules and BEC4 emission reduction project costs. Minnesota Power will also submit 2012 and 2013 Mercury Emission Reduction Plan Reports by July 1, 2012 and July 1, 2013, respectively. Additionally, Minnesota Power will be submitting its 2013 Resource Plan by July 1, 2013. Through these filings, Minnesota Power will provide ongoing information and the latest update on Minnesota Power's plan for mercury and other emission reduction at BEC4 to the Commission, MPCA and other stakeholders. Minnesota Power's ultimate decisions on BEC4 emission reduction will be dependent on final federal rulemaking, available technology for BEC4 emission reduction requirements, and prudent decision-making and investment on behalf of its customers.

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LIST OF ATTACHMENTS

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of Minnesota Power's Annual Filing In Compliance with Minn. Stat. §216B.6851, subd. 5	Docket No. E015/M-12-___ **2012 REPORT**

****

SUMMARY OF FILING

Minnesota Power submits this 2012 Report to the Minnesota Public Utilities Commission ("Commission") in compliance with Minn. Stat. §216B.6851, subd. 5. Through this Report, Minnesota Power provides the Commission, the Minnesota Pollution Control Agency, the Department of Commerce – Division of Energy Resources and other stakeholders an update on the status of the Company's planning and analysis process related to compliance on mercury reduction and other pending emission reduction regulations at its Boswell Energy Center Unit 4. The Company anticipates filing an emission reduction plan for Boswell Energy Center Unit 4 by the end of July 2012.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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In the Matter of Minnesota Power's Annual Filing In Compliance with Minn. Stat. §216B.6851, subd. 5	Docket No. E015/M-12-___ **2012 REPORT**

****

I. INTRODUCTION

Minnesota Power submits this Report to the Minnesota Public Utilities Commission ("Commission") in compliance with Minn. Stat. §216B.6851, subd. 5 as required under Minnesota's Mercury Emissions Reduction Act ("MERA"). Through this Report, Minnesota Power provides the Commission, the Minnesota Pollution Control Agency ("MPCA"), the Department of Commerce – Division of Energy Resources ("Department"), and other stakeholders an update to its 2011 Mercury Emission Reduction Report[1] ("2011 Report") as to how best to achieve compliance with Minnesota's mercury reduction requirements at its Boswell Energy Center Unit 4 ("BEC4"). In addition to Minnesota's mercury reduction statute for utilities, environmental rule making pending or recently passed at the federal level that addresses multiple criteria pollutants, anticipated customer rate impacts from future emission reduction investments and concerns about ensuring the prudence of the overall emission reduction investment at BEC4 have been core in Minnesota Power's thoughtful and strategic approach to meeting the Minnesota mercury reduction mandate.

The Minnesota Mercury Emissions Reduction Act was signed into law on May 11, 2006. The Act targeted six generating units at Minnesota's three largest coal-fired power plants.[2] The original legislation called for Minnesota Power to file with the Commission a 90 percent mercury reduction plan for one of its two wet-scrubbed units, Boswell Energy Center Unit 3 ("BEC3"), by December 31, 2007, with plan implementation by December 31, 2010. The mercury

[1] See Docket No. E015/M-11-712. Background information on BEC4 and the legislative action in 2010 to extend the time period for filing of the BEC4 mercury reduction plan and an extension to the date by which the plan must be implemented is described in the 2011 Report.
[2] Minnesota's three largest coal-fired power plants at the time the legislation was enacted were: Xcel Energy's Sherco and Allen S. King plants and Minnesota Power's Clay Boswell Plant ("BEC").

reduction plan for Minnesota Power's second unit, BEC4, was to be filed with the Commission by July 1, 2011, with plan implementation completed by December 31, 2014.[3] Minnesota Power filed the Boswell 3 mercury reduction plan[4] early and successfully completed the project a year before the deadline.

On May 14, 2010, a bill extending the date to file a 90 percent mercury reduction plan for BEC4 to July 1, 2015 and the date for plan implementation to December 31, 2018 was signed into law. The legislation[5] also stipulated that Minnesota Power submit to the Commission and MPCA, beginning by July 1, 2011, an annual report outlining its emission reduction analysis and potential plans for BEC4. On June 30, 2011, Minnesota Power filed its first report to the Commission.

Minnesota Power continues to actively monitor and assess progress on federal environmental rule makings that affect BEC4 and its other units. At the same time, Minnesota Power has been actively studying BEC4 emission reduction alternatives to ensure timely action, and particularly investigating mercury removal technologies for BEC4, to determine what will be the optimal equipment to install on the Unit. Emission reduction dynamics on BEC4 are more complex than those on BEC3 due to the existing wet particulate and sulfur dioxide removal scrubber. Given the wet scrubber circumstances unique to BEC4, Minnesota Power has used the BEC4 retrofit postponement flexibility to investigate and test mercury emission reduction technology for the unique set of circumstances on BEC4, while actively monitoring certain federal rule makings that could affect BEC4 as they progress to final rules. With the finalization of the MATS Rule and based on other research, analysis and planning it has done, Minnesota Power anticipates filing a BEC4 emission reduction plan with the Commission by the end of July 2012.

[3] One year extensions on both the plan filing and implementation can be obtained with Commission approval. See Minn. Stat. §216B.685, subd. 4(b).
[4] Minnesota Power filed its Boswell 3 Mercury Reduction Plan on October 30, 2006. See Docket No. E-015/M-06-1501.
[5] Minn. Stat. §216B.6851, subd. 5 (See Attachment A)

II. PROCEDURAL SECTION

A. General Filing Information

Pursuant to Minn. Rule 7829.1300, Minnesota Power provides the following required general filing information.

1. Summary of Filing (Minn. Rule 7829.1300, subp.1)

A one-paragraph summary accompanies this Report.

2. Service on Other Parties (Minn. Rule 7829.1300, subp. 2)

Pursuant to Minn. Stat. §216.17, subd. 3 and Minn. Rules 7829.1300, subp. 2, Minnesota Power eFiles the Report on the Department and the Minnesota Office of the Attorney General – Antitrust and Utilities Division. A summary of the filing prepared in accordance with Minn. Rules 7829.1300, subp. 1 is being served on Minnesota Power's general service list. In addition, pursuant to Minn. Stat. §216B.6851, subd. 5(b), Minnesota Power serves this Report on the Minnesota Pollution Control Agency.

3. Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 4(A))

Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722 – 2641

4. Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 4(B))

David R. Moeller
Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 723 – 3963
dmoeller@allete.com

5. Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 4(C))

This Report is being filed on July 2, 2012. There is no effective date or proposed rate change.

6. Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 4(D))

This Report is made pursuant to Minn. Stat. §216B.6851, subd. 5 that requires an annual filing by July 1 of each year until Minnesota Power files its plans for Boswell Unit 4. Minnesota Power's Report falls within the definition of a "Miscellaneous Tariff Filing" under Minn. Rules 7829.0100, subp. 11 and 7829.1400, subp. 1 and 4 permitting comments in response to a miscellaneous filing to be filed within 30 days, and reply comments to be filed no later than 10 days thereafter.

7. Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 4(E))

Lori Hoyum
Policy Manager
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3601
lhoyum@mnpower.com

8. Impact on Rates and Services (Minn. Rule 7829.1300, subp. 4(F))

This filing will have no effect on Minnesota Power's base rates. However, as discussed in this Report, Minnesota Power will need to seek to include in a future rider or base rates the costs to retrofit BEC4 for emission reduction.

9. Service List (Minn. Rule 7829.0700)

David R. Moeller
Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 723 - 3963
dmoeller@allete.com

Lori Hoyum
Policy Manager
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355 - 3601
lhoyum@mnpower.com

B. Statutory Compliance Reference List

In order to clearly identify the location of Minnesota Power's information in response to the statutory requirements for this filing, identification of the section(s) that contain the required information is noted as follows:

- Minnesota Power's mercury control plans for units subject to this section, including how elements of the plans may affect the performance and cost-effectiveness of emission controls for air pollutants other than mercury

  See Sections:

  - IV. Planning and Analysis Update (see page 13)

- Minnesota Power's assessment of the impacts of federal laws regulating various air pollutants emitted by coal-fired power plants that can reasonably be expected to be enacted by 2018 on the utility's units subject to this section, and potential utility responses to those laws, including, but not limited to:

  (i) installing pollution control equipment;

  See Section:

  - III. Environmental Considerations (see page 7)

  (ii) using pollution allowances to achieve regulatory compliance; and

  See Section:

  - V. Other Related Compliance Considerations (see page 15)

  (iii) retiring or repowering the plant that is the subject of the filing with cleaner fuels considering the costs of complying with state and federal environmental regulations.

  See Section:

  - V. Other Related Compliance Considerations (see page 15)

  For each potential response, the report must include an analysis of the impacts on:

- ratepayers,

  See Section:

  - VI. Plan Impact on Customers, Finance and Operations (see page 18)

- the utility's financial position

  See Section:

  - VI. Plan Impact on Customers, Finance and Operations (see page 18)

- utility operations, including the impacts on the service life of affected units.

  See Section:

  - VI. Plan Impact on Customers, Finance and Operations (see page 87)

- The utility shall consult with the agency, the Department of Commerce, and other interested stakeholders to determine which future federal laws to assess and the scope of the assessment of the impact of those laws.

  See Sections:

  - II. Procedural Section (see page 3)
  - III. Environmental Considerations (see page 7)

C. Stakeholder Consultation

The 2011 Report was the first Report filed under the 2010 MERA statute modification and as such provided a baseline picture of the facility, the federal rules that may affect it, and the emission reduction technology alternatives being considered at that time. The 2011 Report also initiated ongoing dialogue with Minnesota Power's stakeholders about BEC4 emission reduction alternatives, costs, and other considerations. In fact, Minnesota Power consulted with the MPCA, the Department, the Minnesota Center for Environmental Advocacy ("MCEA"), the Izaak Walton League and the Large Power Interveners ("LPI") on a draft of the 2011 Report to obtain their feedback prior to filing as required under Minn. Stat. §216B.6851, subd. 5(c). This feedback was used to modify the 2011 Report where applicable and used in follow up communications with stakeholders on the comments they made.

Minnesota Power again consulted with the Department, MPCA, the Izaak Walton League, Fresh Energy, MCEA, LPI and other interested stakeholders on BEC4, as well as its other units, as part of its baseload diversification study process. The baseload diversification study included an evaluation of BEC4 with regard to emission reduction plans and technologies, as well as various evaluations and analyses of Minnesota Power's other generating facilities. Minnesota Power held meetings in St. Paul and Eveleth on November 2 and November 9, respectively, to discuss the methodology used in and the scope of the Company's preliminary analysis. Questions and comments from stakeholders were an integral part of these meetings and further shaped the scope of the study. In addition, at the conclusion of each meeting, Minnesota Power discussed the Commission-ordered three-month comment period following submission of the Baseload Diversification Report and invited stakeholders to contact the Company with any follow-up questions. The baseload diversification study stakeholder discussions, in effect, continued the dialogue process with stakeholders in preparation for this Report. On February 6, 2012, approximately six months after the submission of the 2011 Report and six months prior to the date of this Report, Minnesota Power submitted to the Commission its Baseload Diversification Report containing its baseload diversification study findings as required in its most recent Resource Plan Order.

III. ENVIRONMENTAL CONSIDERATIONS

Assessment of Likely Federal Laws to Be Enacted by 2019

Minnesota Power is closely following several federal rulemakings regulating air and water emissions and solid waste from coal-fired power plants that have recently been, or may be enacted by 2019. They are as follows:

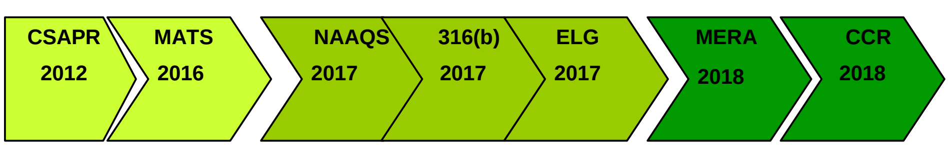
Air Regulations[6]

- **Mercury and Air Toxic Standards ("MATS")**
- **Cross-State Air Pollution Rule ("CSAPR")**
- **National Ambient Air Quality Standards ("NAAQS")**
- **Regulation of Greenhouse Gases**

Water Issues and Ash Management

- Regulation of Coal Combustion Residuals ("CCR")
- Water Effluent Regulation ("Steam Effluent"/ "ELG")
- 316(b) Rule – Standards to Protect Aquatic Ecosystems

In addition to the Minnesota Mercury Emission Reduction Act, these regulations could or will impact BEC4. The timeline below illustrates the current outlook for the expected year in which BEC4 would have to be brought into compliance with these regulations.



[6] Minnesota Power is also closely following regulatory activity specific to the Clean Air Visibility ("Regional Haze") Rule. BEC4 is not a Best Available Retrofit Technology ("BART")-eligible unit and will not be impacted by this phase of the Regional Haze Rule.

In the following paragraphs, Minnesota Power provides an update from the 2011 Report for the regulations (shown in bold above) that will or may experience change in some way since the filing of the 2011 Report.

<u>Mercury and Air Toxics Standards</u>

Under Section 112 of the Clean Air Act, the Environmental Protection Agency ("EPA") is required to set emission standards for hazardous air pollutants ("HAPs") for certain source categories. The EPA published the final Mercury and Air Toxics ("MATS") Rule in the Federal Register on February 16, 2012, addressing such emissions from coal-fired utility units greater than 25MW. There are currently 188 listed HAPs that the EPA is required to evaluate for establishment of Maximum Achievable Control Technology ("MACT") standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources must be in compliance with the rule by April 2015. States have the authority to grant sources a one-year extension and the EPA is assessing other means for granting additional extensions when justified. In order for Boswell Energy Center to attain compliance with this regulation, BEC4 will have to install additional emissions controls.

<u>Cross-State Air Pollution Rule</u>

On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule ("CSAPR"), which went into effect on October 7, 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule ("CAIR"). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed. If the CSAPR is reinstated after judicial review, it will require states in the CSAPR region to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. These regulations do not directly require the installation of controls. Instead, they require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities annually by the EPA and would also be able to be bought and sold.

The CAIR regulations similarly require certain states to improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Minnesota participation in the CAIR was stayed by EPA administrative action while the EPA completed a review of air quality modeling issues in conjunction with the development of a final replacement rule. In its final determination, the EPA listed Minnesota as a CSAPR-affected state based on new 24-hour fine particulate NAAQS analysis. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It is uncertain if the CSAPR-related emission restrictions will become effective for Minnesota utilities.

Since 2006, the Company has significantly reduced emissions at the Laskin, Taconite Harbor and Boswell generating units. This analysis, based on expected generation rates, indicates that these emission reductions would satisfy Minnesota Power's SO_2 and NO_x emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2012. Minnesota Power will continue to evaluate its compliance strategy under CSAPR to determine whether any capital investments or allowance purchases may be required under a possible revised allocation.

<u>National Ambient Air Quality Standards</u>

National Ambient Air Quality Standards ("NAAQS") are established to protect human health ("primary standards") or public welfare ("secondary standards"). The EPA is required to review the NAAQS every five years. If the EPA determines that a states' air quality is not in compliance with a NAAQS, the state is required to establish plans to reduce emissions to demonstrate attainment with that NAAQS. These state plans often include more stringent air emission limitations on sources of air pollutants than the NAAQS require. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

- *Ozone NAAQS.* The EPA has proposed to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to revise the 2008 primary ozone eight-hour standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA was scheduled to decide upon the 2008 eight-hour ozone standard in July 2011, but has since announced that it is deferring revision of this standard until 2013.

- *Fine Particulate Matter NAAQS*. The EPA finalized the NAAQS Fine Particulate Matter (“$PM_{2.5}$”) standards in September 2006. Since then, the EPA established a more stringent 24-hour average $PM_{2.5}$ standard and kept the annual average $PM_{2.5}$ standard and the 24-hour coarse particulate matter standard unchanged. The United States Court of Appeals for the District of Columbia Circuit has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values.

  The EPA proposed a new $PM_{2.5}$ standard on June 14, 2012 with a goal to finalize the standard by December 14, 2012. The EPA proposed adjusting the annual fine particulate standard from 15 ug/m^3 and is accepting comments on whether to set the new standard as 12 ug/m^3 or 13 ug/m^3. The current annual standard of 15 ug/m^3 has been in place since 1997. The EPA is proposing to leave the existing 24-hour $PM_{2.5}$ of 35 ug/m^3 unchanged. The 24-hour standard has been in place since 2006. The EPA is also proposing a separate fine particulate standard in the range of 28-30 deciviews to improve visibility. State attainment status determination will occur after the rule is finalized. It is not known when affected sources would have to take additional control measures if modeling demonstrates non-compliance at their property boundary.

- *SO_2 and NO_2 NAAQS*. During 2010, the EPA finalized new one-hour NAAQS for both SO_2 and nitrogen dioxide (“NO_2”). Ambient monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. The EPA notified states that their plans[7] (“SIP(s)”) for attainment of the standard will be required to be submitted to the EPA for approval by June 2013. One-hour NAAQS attainment will be required by 2017.

  In late 2011, the MPCA initiated modeling activities that included approximately 65 sources within Minnesota that emit greater than 100 tons of SO2 per year. However, on April 12, 2012 the MPCA notified Minnesota Power that such modeling had been suspended as a result of the EPA’s announcement that the June 2013 SIP submittals would no longer require modeling demonstrations for states such as Minnesota where ambient monitors indicate compliance with the new standard. The MPCA is awaiting

[7] State implementation plan(s)

updated EPA guidance and will communicate with affected sources once the MPCA has more information on how the state will meet the EPA's SIP requirements. It is unclear what the outcome of this evaluation will be. These NAAQS could also result in more stringent emission limits on Minnesota Power's steam generating facilities, possibly resulting in additional control measures on some of its units. Compliance with these new NAAQS is expected to be required as early as 2017.

NAAQS can impact BEC4 in two possible ways. First, if facility air dispersion modeling (triggered by a project or permit requirement) demonstrates the NAAQS are being exceeded at the overall Boswell facility ambient air boundary, Minnesota Power would have to take measures to reduce emissions, which may mean a reduction in SO_2, NO_x or particulate matter ("PM") from the BEC4 air emission stack depending on which standards are being exceeded.

Second, if a county which contains one of Minnesota Power's facilities goes into non-attainment, then existing facilities may have to install Reasonably Achievable Control Technology ("RACT") to control emissions. At present, Minnesota Power has not concluded whether the existing controls on BEC4 would meet RACT.

Regulation of Greenhouse Gases

On May 13, 2010, the EPA issued the final Prevention of Significant Deterioration ("PSD") and Title V Greenhouse Gas Tailoring Rule ("Tailoring Rule"). The Tailoring Rule establishes permitting thresholds required to address greenhouse gas emissions for new facilities, at existing facilities that undergo major modifications, and at other facilities characterized as major sources under the Clean Air Act's Title V program. For existing facilities, the rule does not require amending Minnesota Power's existing Title V Operating Permits to include GHG requirements. GHG provisions are likely to be added to Title V permits by the MPCA as permits are renewed or amended. In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific topdown BACT determination process used for other pollutants will also be used to determine BACT for GHG emissions. Through sector-specific white papers, the EPA also provided examples and technical summaries of GHG emission control technologies and techniques the EPA considers available or likely to be available to sources. It is possible that these control technologies could be determined to be BACT on a project-by-project basis.

If provisions of the Tailoring Rule are triggered by a generator, EPA has indicated that they are formulating operational efficiency requirements as a means for containing or reducing carbon dioxide ("CO_2") emissions. Minnesota Power does not anticipate that BEC4 will be subject to requirements under these provisions, since no major modifications that would result in a significant emissions increase (greater than 75,000 tons CO_2 per year) are planned by Minnesota Power for BEC4 by 2019.

On March 28, 2012, the EPA announced its proposed rule to apply CO_2 emission New Source Performance Standards ("NSPS") to new fossil fuel-fired electric generating units. The new NSPS applies only to new or re-powered units, which does not apply to BEC4. However, it is anticipated that the EPA will issue NSPS for existing fossil fuel-fired generating units in the future.

To identify the right plan for BEC4 compliance, Minnesota Power has been working to obtain sufficient information concerning federal rulemakings for various air pollutants, solid ash disposal, water effluent considerations and cooling water intake structures that can affect BEC4. This will help to ensure capital investments at BEC4 are optimal for customers overall in terms of performance and cost. Although several of the federal rulemakings are not yet final, Minnesota Power believes it now has sufficient information and access to proven environmental control technologies that will bring Minnesota Power into compliance with MERA, MATS, and many of the other enacted or pending rulemakings regulating air and water emissions and solid waste from coal-fired power plants. Minnesota Power intends to select the right multiple pollutant control technology for BEC4 as a means of achieving the mercury emissions reduction required while ensuring compliance with other regulatory programs over the long term.

IV. PLANNING AND ANALYSIS UPDATE

Engineering Studies

Understanding the need to make prudent investments on behalf of Minnesota Power's customers, and realizing finalization of federal environmental rules for some pollutants is still pending, Minnesota Power has been proceeding strategically and thoughtfully in determining the appropriate action for BEC4 compliance with MERA. Every effort is being taken to ensure investments in emission reduction equipment for any criteria pollutants on any of Minnesota Power's generating plants, including BEC4, are utilized to the fullest extent of their useful life. Minnesota Power has studied many options for meeting environmental regulations on BEC4 and its other units including those for mercury, NO_x, SO_2 and PM. It is important to recognize that the best alternative for any one pollutant may not provide the best overall solution for meeting other pollutant control requirements. Overall, the goal in multi emission reduction is to cost-effectively optimize the reductions for all pollutants in total.

Since submitting its 2011 Report, Minnesota Power has continued to research options for a multi-pollutant solution for BEC4 that includes refurbishment of its existing components as well as replacement of the existing scrubber with a state of the art design. Both conventional wet flue gas desulfurization systems, as well as various semi-dry technologies, were studied.

In reviewing options that have the potential to produce a 90 percent mercury removal rate at BEC4, Minnesota Power studied the combination of a fabric filter with a powdered activated carbon injection system for achieving a 90 percent reduction in mercury emissions. This is the same technology installed on BEC3 and has been effective in achieving the required level of emission reductions. The study results indicated, however, that installation of this equipment would compromise performance of the existing BEC4 absorber towers used for SO_2 removal. BEC4 is unique in that it utilizes a combination wet particulate removal and SO_2 removal system that has not required a fabric filter or electrostatic precipitator as found in other similar sized coal-fired generating units. The alkaline fly ash that is currently captured in the venturi section and subsequently utilized in the absorber towers for SO_2 emission reduction on BEC4 would no longer be available once a fabric filter is added for particulate and mercury control.[8]

Based on the outcome of the studies conducted in 2007 and 2008 by the engineering firm Burns & McDonnell, and in 2009 by the engineering firm Black & Veatch as a second opinion of available options and costs associated with an environmental retrofit on BEC4, Minnesota Power has been focusing its analysis on the proven state-of-the-art Circulating Dry Scrubber ("CDS") technology for the removal of mercury, PM and SO_2. In a CDS, flue gas enters a vertical reactor tower before exiting to a fabric filter where additional emission capture and collection takes place. Flue gas enters at the base of the vertical reactor tower and flows upward through a short tube called a venturi. Flue gas passing through the venturi mixes with the fluidized bed[9] which is comprised of a mixture of dry lime and fly ash and re-circulated by-product (fly ash) from the fabric filter. The intensive gas-solid mixing occurring at this point in the CDS process promotes reaction of sulfur oxides in the flue gas with the dry lime particles. Water spray is introduced separately above the venturi section for flue gas humidification to enhance the reactivity of the lime and physical absorption for more effective SO_2 removal. Powder activated carbon is injected into the vertical reactor tower for the purpose of capturing mercury and is collected along with the PM in the fabric filter. Introducing the activated carbon prior to the flue gas entering the fabric filter allows for the necessary reaction time to maximize mercury removal.

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[8] For SO_2 removal, the alkaline fly ash is used as an effective replacement for lime which is typically used to remove SO_2 in a wet scrubbing system. If a fabric filter is required the fly ash would no longer be available and a lime/limestone system would have to be added.

[9] A fluidized bed is a layer of small solid particles suspended and kept in motion by an upward flow of a fluid (as a gas). The fluidized bed acts as a reactor for the flue gas to make contact with the reagent.

V. OTHER RELATED COMPLIANCE CONSIDERATIONS

Prospective Controls for BEC4 Other Than Those Associated with Mercury Emission Reduction

As stated in Section III, Minnesota Power is closely following pending federal rules regulating various air pollutants emitted by coal-fired power plants that may be enacted by 2019. Minnesota Power is seeking to avoid decisions that would result in mercury (or any other) emission reduction equipment being installed and then removed prematurely in order to accommodate the subsequent addition of reduction technology for other pollutants. As noted previously, Minnesota Power is also closely following EPA development of the coal combustion residuals, the Section 316(b) fish impingement/entrainment and the steam effluent water rules. By considering other potential environmental reduction beyond mercury, Minnesota Power can ensure the mercury emission reduction investment for BEC4 fits well technically with a multi-emission reduction/environmental improvement installation. The coal combustion residuals rule has the potential to require a large amount of capital investment at Boswell Energy Center so it is prudent for Minnesota Power to be studying the impact of this rule relative to other emission reduction investment for BEC4. Additionally, the water effluent rule that is pending may require the investment of additional capital in part due to BEC4 operations. Taking the necessary time to conduct a thorough analysis of pending federal rules and current and emerging emission reduction technology for various air pollutants as well as solid ash disposal, Section 316(b) fish impingement and entrainment and water effluent considerations, will help Minnesota Power ensure capital investments at BEC4 are optimal for customers overall in terms of performance and cost.

Prospective Air Emission Rule Impacts Beyond Mercury

The following is a description of other emission reduction equipment[10] considered in an air multi-emission reduction installation on BEC4:

[10] Minnesota Power is not ruling out the possibility that Selective Catalytic Reduction ("SCR") technology for further NO_x emission reductions, beyond those achieved with SNCR, could be installed on BEC4 as a result of the pending federal environmental laws in the 2020 timeframe or beyond. Installation of SCR technology would require a significant capital investment by Minnesota Power.

- *Installation of a fabric filter or other enhanced particulate removal equipment.* While Minnesota Power is seeking to avoid the additional investment while still meeting environmental requirements, a fabric filter or other equipment may be required for mercury and other hazardous and/or criteria pollutant removal.
- *A new flue gas desulfurization unit (spray tower absorber) for enhanced SO_2 emission reductions and particulate removal.* The existing scrubber, also referred to as Flue Gas Desulfurization ("FGD"), would have to be modified to operate on lime or limestone or be replaced if a fabric filter is installed for mercury control (see Section V, page 19). The FGD uses fly ash for SO_2 removal. This works simply due to the conditions in the FGD allowing the alkalinity in the ash to react with the SO_2.

Prospective Coal Combustion Residuals Impacts

- *Retrofit of existing ash impoundments.* An eventual federal coal ash rule could require that existing ash ponds be converted from wet to dry systems including those currently utilized by BEC 4.

Prospective Water Effluent Impacts

- Additional wastewater treatment equipment could be required at Boswell Energy Center for BEC4 and other units to meet future EPA water effluent water quality standards.

Retirement or Repowering of BEC4

As an alternative to installing required additional emission reduction technology on BEC4, the costs, operational impact and other factors associated with retiring or replacing BEC4 with natural gas were evaluated as part of Minnesota Power's baseload diversification study. The analysis showed BEC4 continuing to operate as a coal-fired baseload resource for Minnesota Power even with various levels of investment in environmental control technology in the pre-2020 timeframe, as well as the post 2020 timeframe. Minnesota Power will provide more detail of its supporting analysis in its forthcoming BEC4 Environmental Retrofit Plan Petition ("BEC4 Plan Petition").

Using Pollution Allowances to Achieve BEC4 Regulatory Compliance

Under the federal acid rain program, SO_2 emission allowances are already required to support Minnesota Power's regulatory compliance. No new provisions are anticipated through 2019 that would impact Minnesota Power's allowance use for acid rain. Minnesota Power has, and will continue to have a surplus of allocated allowances to cover its SO_2 emissions under this program.

Another allowance-based program, the Cross-State Air Pollution Rule ("CSAPR"), was finalized in 2011. Under this rule, NO_x and SO_2 allowances are required to support compliance. Compliance with this program was originally to begin in 2012. However, due to legal challenges to the Rule, the court has temporarily stayed the Rule while it hears legal arguments. If the allowance allocations for Minnesota Power's facilities do not change significantly, Minnesota Power anticipates an allocation of allowances that will more than offset its annual SO_2 and NO_x emissions. It is still not clear what the outcome of the court challenge will be, nor, if the Rule survives the challenge, when it will be re-instated.

Based on its surveillance of carbon emission reduction policy making, Minnesota Power is not anticipating that CO_2 emission related allowances will be required before 2019. The final MATS Rule does not provide for allowance trading.

In conclusion, at this time Minnesota Power does not anticipate that emission allowance use will play a significant role in BEC4 air emission compliance.

VI. PLAN IMPACT ON CUSTOMERS, FINANCES AND OPERATIONS

Impact to Customers

As identified in its May 8, 2012 press release, Minnesota Power estimates it will invest between $350-400 million over the next few years to comply with current and expected air emission reduction mandates that affect BEC4. Minnesota Power projects overall customer rate increases to span somewhere between 5 percent and 15 percent.[11] Minnesota Power will be able to refine the costs and customer rate increase percentages as equipment, erectors' scope and costs for fully designed projects are identified. Minnesota Power will provide more detail as to the projected rate impacts in its forthcoming BEC4 Plan Petition.

Financial Impact to the Company

Minn. Stat. §216B.683, in addition to Minn. Stat. §216B.1692, provides the ability for Minnesota Power to seek approval for current cost recovery of investments and expenditures related to compliance with MERA through an emission-reduction rate rider. The benefit of current cost recovery is that it better positions a public utility such as Minnesota Power financially to make the necessary investments and expenditures to comply with its statutory mandates. Assuming the Commission approves the BEC4 emission reduction plan the Company plans to file under MERA, the Company has determined it should be able to secure the necessary financings for an emission reduction project with total project costs that fall within the low end to high range of $350 – 400 million assuming current recovery through a rider.

Utility Operations Impact

Minnesota Power operates various coal-fired generating units with varying types of emission reduction technology. Some of this technology is original to the generating unit, while other technologies are new and state-of-the-art. Over the past several years, Minnesota Power has installed numerous emission control systems on all but one of its coal generating facilities,

[11] The estimated customer impact range presented above was calculated based on 2012 budgeted customer billing units, does not reflect fluctuations for potential future load growth, and reflects a range of costs for potential technology option decisions being finalized at the Boswell facility.

including those installed at BEC4. Minnesota Power's experience with constructing and operating emission reduction technologies has prepared its skilled staff well for the installation and operation of future emission reduction investments, whether they are existing or new technologies.

There is a high degree of complexity in operating and managing a large generating unit such as BEC4 today, given the variability of the MISO energy market, fuel quality and supply, customer demands and rapidly evolving external bulk electric system operations and environmental regulations. Minnesota Power considered all of these factors in aggregate when determining the optimum path forward at BEC4. Minnesota Power does not anticipate any significant ongoing operational issues as the result of installing any of the technology that has been studied to date, including the CDS.

Service Life Impact

Currently, there are no planned retirements or changes to BEC4 service life, as outlined in Minnesota Power's most recent annual remaining life depreciation filing[12] and in its Baseload Diversification Report. Minnesota Power will reflect any changes in service life for BEC4 in its future annual remaining life depreciation filings.

VII. SUMMARY

Since 2007, Minnesota Power has studied emission reduction technology options for BEC4 that could optimize emission reduction through prudent investment on behalf of its customers. Simultaneously, Minnesota Power has continued to actively monitor and assess federal rule making for outcomes that could affect BEC4 and its other units.

In February 2012, Minnesota submitted its Baseload Diversification Report containing the finding of its baseload diversification study as ordered by the Commission as a result of Minnesota Power's most recent resource plan filing. The Baseload Diversification Study included Minnesota Power's latest assessment of emission reduction options for BEC4 in light of further information Minnesota Power obtained regarding pending federal emission reduction rules and BEC4 emission reduction project costs. Minnesota Power's BEC4 Environmental

[12] See Docket No. E015/D-12-378 for Minnesota Power's 2012 Remaining Life Depreciation Petition.

Retrofit Project will be presented in the forthcoming BEC4 Plan Petition and will include the necessary level of detail for the MPCA, Commission and other stakeholders to evaluate the cost-effectiveness, reasonableness and emission reductions to be achieved with the selection of this particular environmental control technology.