Xcel Energy

414 Nicollet Mall
Minneapolis, Minnesota 55401

June 14, 2011

-VIA ELECTRONIC FILING-

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: SUPPLEMENTAL FILING TO APPLICATION FOR CERTIFICATE OF NEED FOR THE BLACK DOG REPOWERING PROJECT
Docket No. E-002/CN-11-184

Dear Dr: Haar:

On March 15, 2011, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), made application to the Minnesota Public Utilities Commission (the "Commission"), for a Certificate of Need for about 700 MW of natural gas fueled, combined cycle generation to replace the 250 MW of existing coal fueled generation remaining at the Black Dog Power Plant. Since our filing, the Spring 2011 forecast has been developed as part of our normal annual forecasting and budgeting cycle.

We provide this update to summarize our Spring 2011 forecast and explain why our updated analyses leads the Company to conclude that January 2016 is still the date we should target as the commercial operation date for the Project.

Please do not hesitate to contact me at (612) 330-6732 or james.r.alders@xcelenergy.com if you have any questions. Thank you.

SINCERELY,

/s/

JAMES ALDERS
DIRECTOR REGULATORY ADMINISTRATION

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Northern States Power Company for a Certificate of Need for the Black Dog Generating Plant Repowering Project

Docket No. E002/CN-11-184

SUPPLEMENTAL FILING IN RESPONSE TO COMPLETENESS ORDER

INTRODUCTION

Applicant Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") respectfully submits this filing pursuant to Minn. R. 7849.0200, subp. 5, and the May 25, 2011 *Order Finding Application Complete When Supplemented, Setting Deadline for Alternative Proposals, and Initiating Informal Review Process* ("Completeness Order") issued by the Minnesota Public Utilities Commission ("Commission"). In its Completeness Order, the Commission found that the Certificate of Need Application for the Black Dog Generating Plant Repowering Project ("Project") will be deemed substantially complete upon making this filing (the "Supplemental Filing") to update the Commission on the Company's Spring 2011 forecast.

Xcel Energy appreciates this opportunity to update the Commission and stakeholders on the Spring 2011 forecast and our Project. We have organized this Supplemental Filing into the following three discussion areas:

- <u>Forecast Update</u>: The Spring 2011 forecast predicts demand will be 385 MW lower by 2016 than the 2010 forecast. This decline is due to a combination of reduced firm wholesale municipal load, lower actual peak demand in 2010, and updated economic performance indicators that predict slightly slower growth. As the result of the Spring 2011 forecast, we project a capacity deficit by 2016 of approximately 70 MW. While we have some flexibility in retiring Black Dog Units 3 and 4, the 2016 capacity deficit increases to 320 MW if the units are retired in 2016 as originally planned. While our Spring 2011 forecast results remain within the range of forecasts presented in our Certificate of Need application, the change caused us to reexamine the appropriateness of the Project.

- Project Remains Appropriate: The Spring 2011 forecast does not change our recommendation for proceeding with the Project. The Project replaces 253 MW of older coal-fired generation with about 700 MW of efficient natural gas generation with lower overall emissions. Federal environmental initiatives lead us to conclude we cannot cost-effectively continue to operate Black Dog Units 3 and 4 on coal beyond 2014. The Black Dog Repowering Project continues to compare favorably to the alternative of deploying combustion turbines (the Alternative Generation option) on our system. We have the flexibility to operate Black Dog Units 3 and 4 on natural gas during a transition to a new, replacement resource. However, we do not recommend extended operations at these older units on natural gas, due to increasing risk of mechanical breakdown and inefficient operation on natural gas. Further, the Project utilizes an existing plant site located strategically on our system and minimizes environmental and socioeconomic impacts.

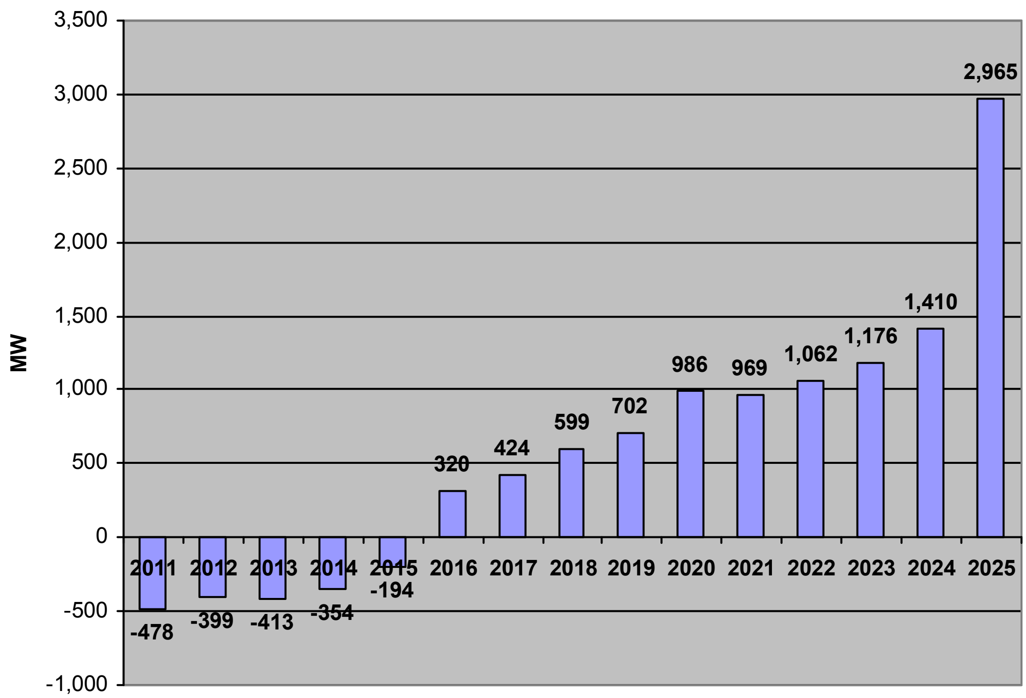
- Project Timing and Risk Management Considerations: In recent years, we have seen our forecasts fluctuate more widely than in the past. The Spring 2011 forecast is no exception to this trend. When we analyze the Project using the Spring 2011 forecast, Strategist suggests there may be an economic benefit to delaying the Project completion date. On the other hand, we believe that construction costs could come under significant upward pressure in the next couple of years due to rising prices and competition from other similar projects. Utilities nationwide will need to grapple with new EPA regulations, retire older coal plants and possibly replace them with natural gas combined cycle facilities.

  We conclude the proposed 2016 schedule minimizes the risk of cost increases and preserves flexibility. If demand remains low and upward cost pressures do not materialize, we can defer or extend implementation. By contrast, if the Project is delayed now, we will have little flexibility to accelerate development later if forecasts rebound or other circumstances point to the need for the 2016 in-service date.

I. Forecast Update

The Company developed the Spring 2011 forecast as part of our normal annual forecasting and budgeting cycle.[1] The median Spring 2011 forecast estimates that demand will start from a lower than previously expected 2010 base, will grow at a slower rate than our 2010 forecast, but will still result in a capacity deficit in 2016. If we assume Black Dog Units 3 and 4 will be retired, our 2011 forecast shows a capacity deficit of 320 MW in 2016, growing to 424 MW in 2017 and 599 MW in 2018 as depicted in Revised Figure 1-2 and 3-6.

Revised Figure 1-2 and 3-6: Forecasted Resource Needs by Year*



*assumes Black Dog Units 3 and 4 are retired in 2016

The Spring 2011 system demand estimate is approximately 385 MW lower in 2016 than indicated in the forecast used in our original Application. The change is largely due to a reduction in firm wholesale load and lower 2010 weather normalized peak demand.

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[1] The Spring 2011 forecast will be filed in the normal course of business on July 1, 2011 as part of our Minnesota Electric Utility Annual Report.

A. Firm Wholesale Customers

Xcel Energy has historically provided firm wholesale service to a number of municipal utilities in Minnesota and Wisconsin from our system resources. Recently, we have received notifications from all but one of our Minnesota firm wholesale customers and all of the Wisconsin firm wholesale customers that they will not be renewing their contracts when they expire. This represents a cumulative 229 MW reduction in demand by 2014. The 2010 forecast included a 65 MW reduction for the contracts that we knew were not going to be renewed when that forecast was prepared. At the time, we knew others were considering termination of their contracts and, in fact, received two additional notices representing nearly 50 MW. While these alone were not significant enough to warrant a forecast change, we have since received termination notices from the remaining wholesale municipal customers. The 2011 forecast includes adjustments to reflect an additional reduction of 164 MW.

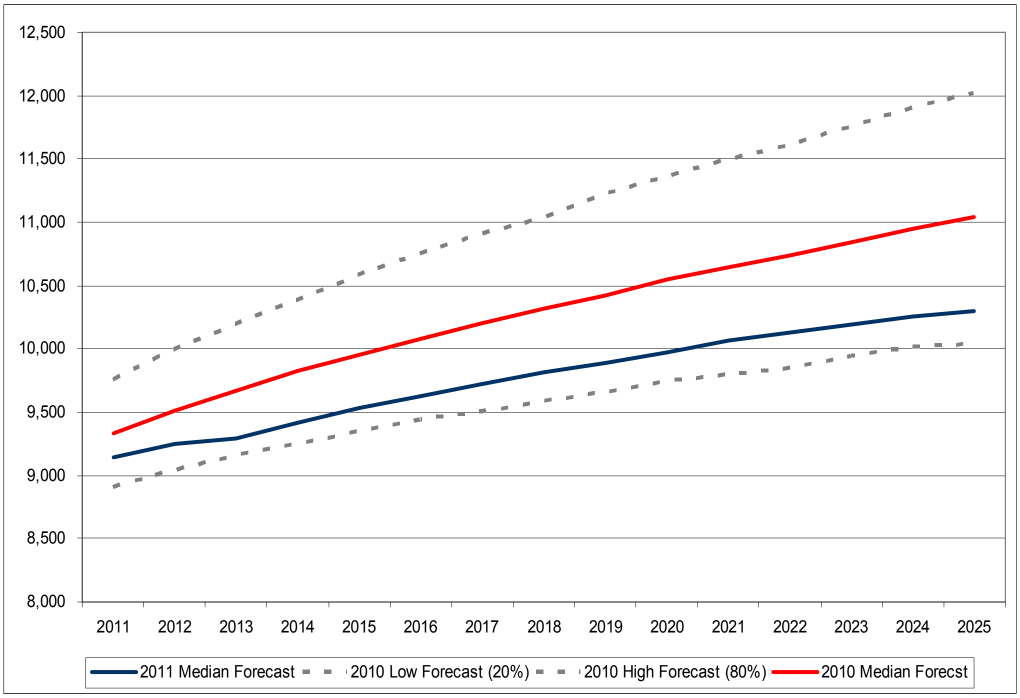
B. 2011 Median Peak Demand

The actual 2010 weather-normalized peak demand was lower than we had forecast last year. When 2010 results are incorporated, a 119 MW lower demand level is used as the starting point for the Spring 2011 median peak demand forecast. In addition, we are using refinements to our model assumptions that tie with historic data as well as updated economic indicators which suggest a weaker economy. Thus, using actual data through December 2010 and the most recent economic forecast obtained from Global Insight, Inc. (January 2011), our 2011 forecast for median peak demand in 2016 was reduced by approximately 240 MW. In addition, we are projecting lower impacts on peak demand from our DSM programs of approximately 20 MW by 2016 while achieving the same level of energy savings associated with our DSM programs.

C. Forecast Remains within Projected Range

Forecasts are estimates based on a specified set of assumptions. Actual results will differ from even the most carefully constructed forecast. Since any forecast contains some uncertainty, we conduct sensitivity analyses to assess a range of possibilities. In our Application, we described the sensitivity analyses we conducted. The 2011 Spring forecast still falls within that sensitivity range and thus is captured in our original range of sensitivity analyses, although it is fairly close to the bottom of the range. New Figure 3-7 illustrates how the 2011 median forecast falls within the 2010 bandwidth.

New Figure 3-7: Forecast Sensitivity



The change in our forecast has led us to reexamine our analyses of alternatives, timing and risk factors. It will be important to continue to monitor forecasts closely and to assess evolving economic indicators. If trends weaken further, it may be prudent to move more slowly and implement the project at a later time than January 2016. We propose to update the Commission on evolving forecast trends and whether or not they change our recommendation.

II. Project Remains Appropriate

In this section we discuss that even in light of the Spring 2011 forecast, we continue to believe replacing 253 MW of older coal generation from Black Dog Units 3 and 4 with about 700 MW of combined-cycle generation at the same site is the best way to meet customers' needs. Using the Spring 2011 forecast, the Project continues to perform well against the alternatives. While the magnitude of the differences is smaller, the Project still results in a lower present value of revenue requirements ("PVRR") over the long run. Revised Tables 4-1 and 4-2 update our analysis with the Spring 2011 forecast.

Revised Table 4-1: Cost Comparison as Compared to Alternatives ($000s)

	PVRR	Difference from Project
Black Dog Repowering Project	$98,142,253	---
Alternative Generation	$98,160,274	$18,021
Black Dog Life Extension	$98,561,684	$419,431
Biomass Alternative	$99,187,027	$1,044,774

As discussed in our original Application, the Alternative Generation Option assumes that we discontinue operating Black Dog Units 3 and 4 at the end of 2014 and Strategist is allowed to select new generic resources to replace the output of Units 3 and 4. Strategist selected combustion turbines to be installed in lieu of the Project, the first in January 2018. (Prior to that time, capacity deficits are covered by purchasing short-term capacity.) Investing in pollution control equipment to meet pending environmental regulations and refurbishing or replacing aging equipment to keep Black Dog Units 3 and 4 operating on coal remains a distant third alternative.

We continue to conclude it is prudent to retire Black Dog Units 3 and 4 as part of our Project and the Project is preferred to adding additional combustion turbines (the Alternative Generation option). Revised Table 4-2 provides further information on the Project compared to the alternatives.

Revised Table 4-2: Cost Sensitivity Analysis – PVRR Comparison ($000s)

	2016 Black Dog Repowering Project	Alternative Generation Difference from Repowering	Black Dog Life Ext Difference from Repowering	Biomass Difference from Repowering
Base ($0 CO_2)	$98,142,253	$18,021	$419,431	$1,044,774
High Gas (+20%)	$99,294,406	$33,287	$291,636	
*Low Gas (-20%)	$96,978,908	($1,546)	$545,983	
High Load (80th Percentile)	$102,124,604	$127,373	$512,453	
*Low Load (20th Percentile)	$95,828,785	($128,923)	$411,981	
High CO_2 ($34/2012)	$108,540,318	$97,090	$896,753	
Mid CO_2 ($17/2012)	$103,340,852	$47,261	$647,897	

Low CO_2 ($9/2012)	$100,889,387	$32,525	$538,167	
Late CO_2 ($15/2017)	$101,181,286	$26,060	$567,818	
*Very High Capital Expenditures +20%	$98,276,309	($116,034)	$285,375	
*High Capital Expenditures +10%	$98,209,281	($49,007)	$352,403	
Low Capital Expenditures -10%	$98,075,225	$85,049	$486,458	
No New Wind	$98,088,457	$18,000	$416,447	
No MISO Market	$98,164,440	$53,827	$423,485	
High Externalities	$98,473,039	$15,047	$451,178	
Low Externalities	$98,267,948	$15,898	$441,473	
3.9% Capital Escalation	$98,142,253	$60,484	$419,431	
5.9% Capital Escalation	$98,142,253	$107,808	$419,431	

The Project remains the least-cost option in all cases except the four sensitivities that are marked above. We provide a brief discussion of these four sensitivities for the Commission's consideration to demonstrate that these sensitivities should not unduly influence the Commission's analysis or decision.

A. Low Gas (-20%) Sensitivity Analysis

Our analysis found that if natural gas prices are 20% lower than forecast, the Alternative Generation scenario results in a small savings. The savings, less than $1.5 million, are quite small in comparison to the overall system PVRR of $98 billion. What drives this small difference is the trade-off between the lower upfront capital cost and the lower unit efficiency of combustion turbines compared to the higher upfront capital cost and higher efficiency of combined cycle technology. To make the combustion turbine option the more attractive option assumes that long-term gas prices will decline to a level 20 percent below the most recent gas price forecasts. Although the recent trend of natural gas prices has been downward, we believe our natural gas price forecast adequately captures these trends and that the natural gas prices in this scenario are highly unlikely to occur.

B. Low Load (20^{th} Percentile)

If we experience sustained lower than expected growth, the Alternative Generation scenario results in a PVRR savings of nearly $130 million. Such sustained low demand is inconsistent with our current economic analysis. On the other hand, the economic recovery that seemed so solid just a few months ago appears to be softening again. The very real risk that load growth will be slower than forecasted is better addressed in our consideration of the timing of the Project. As further discussed below, the Project may need to be delayed if we continue to see low load growth.

C. Higher Capital Expenditures

This sensitivity shows the system costs with the Project exceed the Alternative Generation scenario by $49 and $116 million if costs of the Project increase 10% and 20% respectively. This sensitivity assumes that the Project's capital costs increase but the Alternative Generation costs remain flat. This mismatch is unlikely and results in an 'apples v. oranges' comparison. A more realistic scenario is that the same forces causing Project cost increases would also impact the Alternative Generation proposal. Likewise if the Project is delayed and becomes more expensive due to increased competition and cost escalation, the Alternative Generation option would face the same competition and see similar cost increases.[2] We also developed two scenarios that would reflect this situation – one where capital costs were escalated by 3.9% for all new resources, and one where capital costs were escalated by 5.9%. In both of these scenarios, the Project was more cost-effective than the Alternative Generation scenario.

III. Timing and its Relationship to Risk Management

The lower Spring 2011 forecast has caused us to further evaluate the appropriate timing for the Project. In reexamining timing, Strategist predicted that under current assumptions there may be an economic benefit to customers from delaying the Project.

[2] In our currently pending rate case (Docket 10-971), the issue was raised of what is the appropriate standard to judge cost estimates at the Certificate of Need stage. Typically, cost estimates have not been detailed or designed for rate making purposes but rather as high-level estimates sufficient to judge among alternatives. Once a Certificate of Need is granted, the Commission will retain its authority to review the prudency of expenditures. If the Project is selected and experiences increased capital costs, it will be appropriate for the Commission to consider actual costs incurred in light of all of the circumstances, including the impact of delay, market forces and unforeseen contingencies.

New Table 4-1(a) Strategist Analysis with Changing In-service Dates ($000)[3]

	PVRR	Difference From 2016
Black Dog Repowering 2016 in-service date	$98,142,253	
Black Dog Repowering 2017 in-service date	$98,115,684	($26,569)
Black Dog Repowering 2018 in-service date	$98,098,271	($43,982)

In the 2016 case, coal operations at Black Dog Units 3 and 4 cease in 2013, but the units continue to operate using natural gas until the Repowering Project is completed. In the 2017 and 2018 cases, Black Dog Units 3 and 4 cease coal operations in 2014 as required[4] by recently proposed air quality regulations that are expected to be finalized by the end of 2011. In each case the units would operate on natural gas until the Project is completed. We did not examine delays beyond 2018 since the forecast indicates a new resource would be needed in the 2018/2019 timeframe to meet load growth even if Black Dog Units 3 and 4 continue to operate on natural gas. In addition to the economic results shown above, we have identified a number of other factors to consider in assessing the appropriate Project timing.

- <u>Forecast Risk</u>: If the Project is not completed in 2016 but demand forecasts rebound, we risk having to acquire additional short-term capacity on the MISO market and/or expedite the addition of peaking capacity.

- <u>Cost Risk</u>: We expect increasing competition and price pressure in the equipment and construction markets due to the impact of environmental regulations and coal plant retirements. Continued operation of Black Dog Units 3 and 4 on natural gas also increases the risk of mechanical breakdown at these older units.

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[3] New Table 4-1(a) presents the results of Strategist modeling that varies the in-service date of the Project based on the same modeling assumptions used in our original Application, including a 1.9 percent escalation rate. Externality values and carbon dioxide regulation cost estimates are excluded.

[4] Note that using the term required is based on our analysis that it is cost prohibitive to install the additional pollution control equipment to continue coal operations.

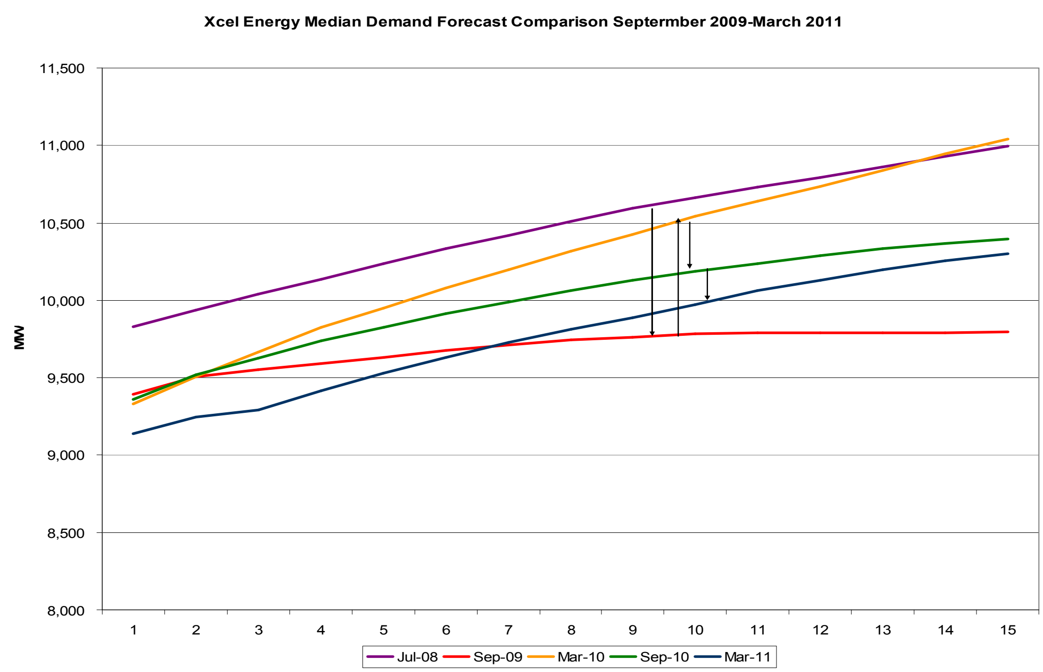
- Other Risks Considered: We looked at a number of other risks as well, including (i) the impact of delay on the cost and timing of our air permit, (ii) emissions netting and offset issues, and (iii) the potential for staging Project deployment. While these risks do not drive our recommended timing, they were an important part of our analysis.

A. Forecast Risk

Forecasts are by their nature predictions of future events based on a set of assumptions. Actual results will differ, depending upon how actual circumstances develop. This risk requires utilities to plan prudently to ensure that sufficient capacity is available to serve customers under all reasonable scenarios.

To mitigate this forecast risk, we update our forecasts each spring for budget and planning purposes. Our forecasts use historical trends and key economic indicators to predict future demand. Recently, the economy has been more difficult to predict. Fluctuations have had a larger impact than during periods of more stable economic performance. This recent fluctuation is depicted in New Figure 3-8.

New Figure 3-8: Forecast Fluctuations

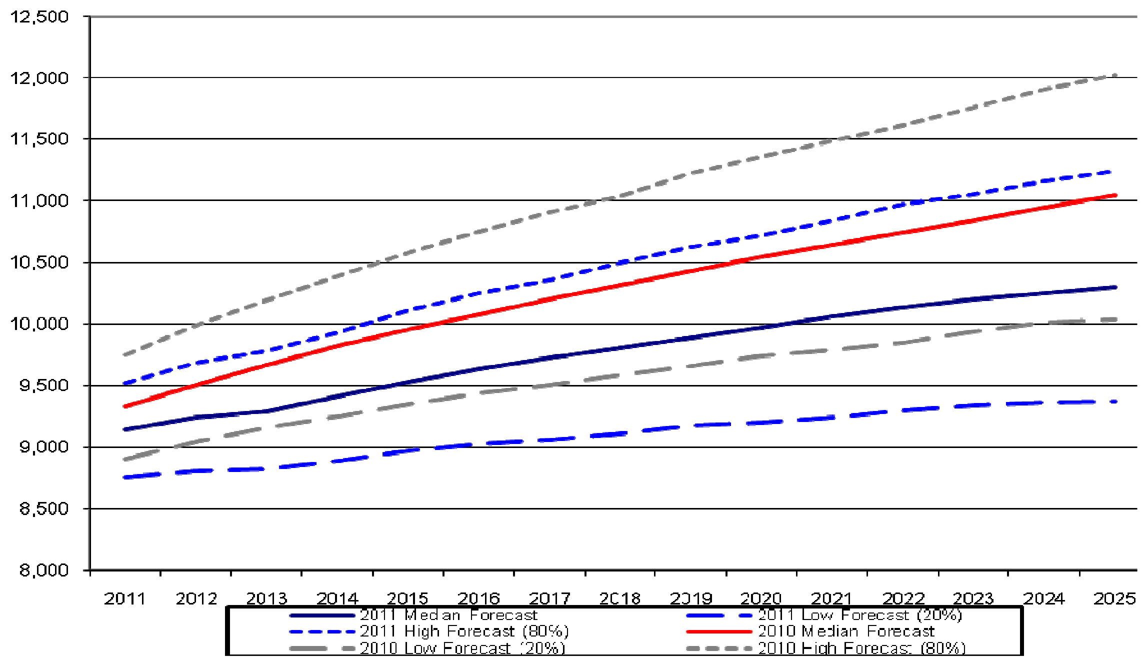


While the changes in our forecasts have been small as a percentage of our total resource requirements, these small shifts can affect the timing of resource additions. For example, a change of only 2% is about a 200 MW change in resource need.

Thus, if demand forecasts rebound even a small amount, delaying the Project now could result in needing to meet customer demands through greater reliance on the short-term capacity market. A larger rebound could require installing peaking units on short notice to meet our reliability requirements.

While we have provided median demand forecasts for the Commission to consider, we believe that it is most appropriate to consider the range of possible demand outcomes as depicted below in New Figure 3-9.

New Figure 3-9: Comparison of 2010 to 2011 Forecast Ranges



Although our analyses suggest that it would be reasonable to delay the in-service date for Black Dog to 2017 or 2018, we are concerned that if our forecast suddenly rebounds we will not be able to reestablish a 2016 in-service date in the future. As a result, we recommend that we maintain the currently proposed 2016 in-service date for now. As we update our forecast, we will provide results to the Commission. Updated forecast information will be available before major procurement commitments need to be made for the Project. At that time, we will reevaluate the Project and make further recommendations on timing if necessary.

B. Cost Risk

In reviewing Project timing we identified the risk that costs could escalate significantly in the relatively near future due to competition in the construction market. Industry studies show that emerging EPA regulations create the potential for anywhere from

25 to 75 GWs of coal retirement in the near term.[5] Power Magazine recently predicted "a loss of 50 GW of U.S. coal-fired capacity over the next decade." The Brattle Group reports that 12-15 GW of the coal generation in the MISO region will be retired by 2020 and that this generation will be replaced by natural gas generation.

Many utilities are reviewing the proposed EPA regulations and completing studies to determine if some of their older coal plants should be retired and which ones, due to transmission constraints and reserve margins, must be replaced. It is anticipated that these utilities may be about six to twelve months behind where we are today in our planning process and therefore we may have a timing advantage that could result in a cost advantage.

We do not predict a change in Project costs if we retain a 2016 commercial operating date, since commitments to major equipment can be made in 2012. However, we are already seeing indications of cost increases in key commodities such as copper and steel. We are concerned that deferring implementation beyond 2016 could result in cost escalation of Project components that is higher than our general inflation indicator of 1.9%. New Table 3-2 depicts the sensitivity of the Project to price escalation changes based on changes in timing.

New Table 3-2: Capital Cost Risk ($000)

	PVRR	Difference From 2016 Black Dog PVRR	
	2016 Black Dog Repowering	2017 Black Dog Repowering	2018 Black Dog Repowering
Base (1.9%/yr Capital Cost Increase)	$98,142,253	($26,569)	($43,982)
3.9%/yr Capital Cost Increase	$98,142,253	($13,347)	($18,694)
5.9%/yr Capital Cost Increase	$98,142,253	($126)	$7,096

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[5] The current U.S. coal fleet includes approximately 314 GW of coal generation, with 265 GW of that generation located within the Eastern Interconnection. The specific market and industry ramifications resulting from EPA's proposed Clean Air Transport Rule (regulating SO_2/NOx interstate pollution transport) and hazardous air pollutants regulations (utility MACT) are not entirely clear. A number of leading industry consultants, including M.J. Bradley and Associates, Charles River Associates, The Brattle Group, ICF International and Credit Suisse, have published studies identifying the expected impact on coal generation and future gas generation from these anticipated EPA regulations.

Although a delayed approach to the Project may be economic based on the Company's current inflation expectations, higher escalation rates decrease and even eliminate the economic benefit of delay.

Deferring the Project would also require us to continue operating Black Dog Units 3 and 4 on natural gas beyond 2016. Although Xcel Energy has provided the appropriate maintenance to ensure the reliability of these older units, their boilers, turbines and generators are essentially original equipment. As one would expect from 50 year old assets, recent operating data shows declining availability and their operation becomes less predictable. And older assets are at a heightened risk for expensive mechanical breakdowns.

If we experience major component failures on these units, our capacity position could change by as much as 250 MW. This capacity would need to be replaced, either by short-term capacity purchases or expedited construction. Structural changes in the MISO capacity market[6] and the potential loss of other older coal generation in MISO as discussed above may make it more difficult to purchase short-term capacity at a reasonable cost. As a result of these risks, we believe it would be prudent to minimize our reliance on Black Dog units 3 and 4 beyond 2016.

C. Other Risks Considered

In assessing the potential impacts of the Spring 2011 forecast, we looked at a number of additional factors. While none of these was dispositive, this review was helpful to test our analysis and associated recommendation.

Air Permitting Delay and Netting
The Project must obtain an air emission permit. If the Project is delayed or materially modified, we would likely have to resubmit our air permit application and restart our environmental review. The air quality permitting process allows us to compare or "net" the emissions from the new Project with those of the existing coal-fired units and determine the net increase/decrease of various emissions.[7] The netting rules

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[6] MISO has been working for the past year to develop a new reliability construct for the region. MISO's proposal is based on two components: a robust capacity market for 3-5 years forward and pricing that recognizes the capacity transfer limits between various regions within the MISO footprint. However, this capacity market is not yet well-established and remains subject to significant transmission constraints and limitations that reduce the flexibility potential from the MISO capacity market.

[7] By virtue of the change in fuel to natural gas, state-of-the-art combustion technology, and catalytic reduction and oxidation technology, the emission of almost all regulated pollutants will be lower from the new facility compared to Black Dog Units 3 and 4. Volatile organic compounds emissions are anticipated to be higher than existing levels with the assumption of an allowable capacity factor of 70%.

specify that the baseline emission levels from the existing plant are determined by looking at 24 consecutive months of annual emissions within the five year period of time before the new facility is under construction. Construction of the Project would need to start no later than spring 2017 to allow netting against coal-fired emissions occurring prior to 2014 (when coal generation will cease). Thus, we concluded that air quality permitting can be successfully completed with minimal risk if the Project is delayed a year.

Offsets
We also reviewed the impact that a change in ambient air quality standards in the Twin Cities area could have on air permitting if the Project is delayed. There is a potential risk that the Twin Cities could be found in nonattainment of ambient standards for ozone and fine particulate matter in the next few years. In that circumstance, nonattainment new source review provisions of the air quality rules would apply. In a nonattainment situation, emission limits for the pollutants of concern would be reduced. We would have to arrange for emission reductions at some other emission sources in the area to offset the emissions from the Project. Minnesota does not have experience with the timing and cost of deploying such an offsets program. It is not clear what the impact of the change would be on the Project. However, we believe there is a relatively low probability that the change would happen within the next two years, which would be the timeframe that would affect air permitting. While the risks of cost and complications from nonattainment are real, we concluded they were manageable and contribute only slightly to our consideration of the in-service date.

Staging Deployment
In preparing our original Application, we considered as an alternative, a phased construction process to install the combustion turbine portion of the Project in 2016 and the heat recovery and steam turbine portion in 2018. The economic analyses completed at that time showed that the phased construction option was more expensive due to the need for multiple deployments of construction forces and other inefficiencies. Thus, we did not re-examine this alternative at this time. Additionally, it should be noted that once we start Project construction, a phased approach will most likely not be feasible.

D. Flexibility Benefits Support Current Schedule

The lower Spring 2011 demand forecast makes the timing analysis more sensitive to capital cost assumptions and risks that can influence costs. While there are scenarios where deferring the Project by a year or two could result in reductions in long term system costs, we conclude that the forecasting and cost risks described above expose our customers to risks that can be mitigated by maintaining the proposed 2016 in-service date at the present time.

Construction of major infrastructure is a complex and multi-year process. If the Commission approves the recommended 2016 in-service date, Xcel Energy will continue currently-planned activities to implement that decision. During the implementation process we intend to monitor economic trends and evolving circumstances and adjust accordingly if necessary. We will need to proceed with renovation of the coal yard in spring of 2012[8] in order to ensure a 2016 in-service date. However, we will have additional opportunities to adjust timing if warranted before equipment commitments and actual construction starts.

We will notify and update the Commission if we believe a change in timing is in the best interests of our customers. Given the circumstances, we propose to provide the Commission with an update in the Spring of 2012 before we proceed with key development milestones such as commitments to major plant equipment. We would support the Commission including this update as a condition of granting the Certificate of Need.

If the Commission determines that the Project should be delayed to a later in-service date, the Company will need to design an implementation schedule and contractual commitments consistent with that direction. Long lead time procurement and major construction activities will not allow us to accelerate that schedule if the demand forecasts rebound or circumstances otherwise show that the 2016 date is necessary. If higher demand materializes before the plant is completed, we will need to pursue other options to fill shortfalls.

Even if the Commission is concerned about the proposed timing of the Project, we recommend that it authorize a 2016 in-service date, recognizing that the Company could delay the in-service date if future forecasts continue to indicate a weak economic climate, or other circumstances call for resetting the date.

While we acknowledge that this approach creates potential challenges related to implementation schedules and evaluation of competitive alternatives, the flexibility it offers will allow us to best manage the balance between proceeding immediately and slowing down as circumstances develop. Xcel Energy appreciates the Commission's

[8] Note that the Company's estimate of $70 million for unavoidable site remediation will be incurred regardless of whether this Project or an alternative is pursued.

guidance on the factors to be considered in deciding whether to accelerate or defer work as circumstances develop.

CONCLUSION

Xcel Energy appreciates the opportunity to provide the Commission and stakeholders with this Supplemental Filing. We continue to believe that the Project is the most appropriate alternative for the Commission's consideration. While the Spring 2011 forecast raised questions about timing, it does not change the Company's overall recommendation. We look forward to a comprehensive and fair review of this Project and any competing proposals that may be submitted to the Commission as part of this process.

Dated: June 14, 2010

Northern States Power Company,
a Minnesota corporation

/S/

By: ______________________________

JAMES ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

CERTIFICATE OF SERVICE

I, Lindsey Didion, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/CN-11-184

Dated this 14th day of June 2011

/s/

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Lindsey Didion
Administrative Assistant

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