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Rebuttal Testimony and Schedules
Steven W. Wishart

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Petition to the Minnesota Public Utilities Commission Seeking Approval for a Competitive Resource Acquisition Proposal
And For a Certificate of Need

Docket No. E002/CN-12-1240
Exhibit___(SWW-2)

Department of Commerce Strategist Analysis, Calpine Levelized Cost of Energy Analysis, Firm v. Interruptible Natural Gas Supply, and Other Strategist Issues

October 18, 2013

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Schedules

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Steven W. Wishart. I am Director of Resource Planning and Bidding for Xcel Energy.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes, I provided direct testimony on (i) the Company's assessment of anticipated generating capacity deficits in the 2017 to 2019 timeframe; (ii) the Strategist analysis we performed to evaluate the proposals that are the subject of this proceeding; (iii) the Company's recommendation regarding which proposals should be selected by the Commission; and (iv) important considerations that need to be addressed in the next phase of the process, the negotiation of power purchase contracts.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to various issues raised in the Strategist analysis provided by Department witness Dr. Steve Rakow and the Least Cost of Energy (LCOE) analysis of Calpine witness Mr. Paul Hibbard. I also provide an analysis of the benefits of firm versus interruptible natural gas supply as requested by Department witness Mr. Sachin Shah. I conclude by responding to various Strategist issues raised by other witnesses regarding the proposals in this proceeding.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. A summary of the principal issues in my rebuttal testimony is provided below:

A. The Department's Strategist Analysis

The direct testimony of Dr. Rakow provided an alternative Strategist analysis to the Company's comparing the cost and benefits of the proposals in various portfolios. Although our methodologies were substantially different, we both identified a combination of Black Dog 6 and Calpine's Mankato Expansion as the least cost alternative to meet the Company's identified need. However by only evaluating projects through 2036, Dr. Rakow does not address the long-term cost savings that Company-owned projects offer our customers in comparison to power purchase agreements (PPAs). When the long-term benefits are considered, Black Dog 6 is the most attractive proposal in this process, and Calpine's Mankato Expansion project and Invenergy's Cannon Falls Expansion project are in close competition for second place.

The Department's analysis also did not recognize the timing flexibility that our projects have. Changes in both our and the Department's assessments of the Company's future capacity need underscore the value of flexibility regarding in-service date. To minimize costs for our customers, we are willing to adjust the in-service date of our proposal to best match the first year of actual capacity need.

B. Calpine's Levelized Cost of Energy

We used Strategist modeling because it provides a complete cost-benefit analysis. Mr. Hibbard presented an analysis of the proposals in this proceeding based on their estimated levelized cost of energy. The primary short coming of the LCOE method is that it compares the proposals based on

their costs alone, completing ignoring the avoided costs the Company would realize as the result of each project being added to our system. Thus the LCOE approach is only a partial analysis. I recommend Mr. Hibbard's LCOE analysis not be considered in the selection of resources in this proceeding.

C. Firm vs. Interruptible Natural Gas Supply

In response to Mr. Shah's request, I attempt to clarify the costs and benefits of firm natural gas supply in comparison to interruptible service. Currently, the Company's system has approximately 1,800 MW of excess winter capacity in comparison to 800 MW of excess capacity in the summer. Although we would typically prefer year-round firm natural gas supply, interruptible service that may be curtailed in the winter does not significantly impact our ability to reliably serve customers, and it offers significant cost savings. In our analysis, we consider interruptible natural gas service only to be a viable option for peaking units. Peaking units such as those proposed by the Company and by Invenergy are typically only dispatched in the summer during periods of high customer demand. Intermediate units such as the combined cycle unit proposed by Calpine are dispatched frequently during the winter months, and therefore firm natural gas service is mandatory fort those types of units.

II. DEPARTMENT OF COMMERCE STRATEGIST ANALYSIS

Q. WHAT IS THE DEPARTMENT'S RESOURCE SELECTION RECOMMENDATION?

A. Dr. Rakow states on page 40 of his direct testimony that Calpine's Mankato Expansion in 2017 combined with our Black Dog Unit 6 in 2019 is the least cost package that "covers Xcel's capacity deficit to 2023 under the normal

forecast and to 2025 and beyond under the mid-low and low forecasts." Dr. Rakow then goes on to state that if the Commission is concerned about "the size of the package," the second ranked package under base case conditions is Calpine's proposal. He concludes with the observation that Black Dog 6 in 2017 or a combination of Invenergy's and Calpine's proposals are also options depending upon "which contingencies are of greatest concern" to the Commission.

Q. DO YOU AGREE WITH THE DEPARTMENT'S RECOMMENDATION?

A. In part. We agree that the combination of Black Dog 6 and Calpine represents one least-cost package. However as presented in our direct testimony, our analysis shows the combination of Black Dog 6 and Invenergy Cannon Falls represents another least-cost package, and therefore we recommend that both Calpine and Invenergy should proceed to the PPA negotiation phase of these proceedings.

In addition, we believe that Black Dog 6 should be selected under any resource need assessment. This is based on the fact that Black Dog 6 has the lowest PVSC of all the proposed resources, and the unit offers the Commission the flexibility to delay its implementation to achieve the best match possible with the Company's actual need in the 2017-2019 time period.

Q. WHAT IS YOUR ASSESSMENT OF THE STRATEGIST ANALYSIS PERFORMED BY THE DEPARTMENT?

A. First, Dr. Rakow's Strategist analysis is well thought out and clearly presented. The Company appreciates the Department choosing to conduct a Strategist

analysis because it acts as a check and balance to our own Strategist simulations. An examination of the similarities and differences between our respective results provides an opportunity to determine which of the proposals in this proceeding can most cost-effectively address our potential range of need in the 2017-2019 time period.

With respect to the principal differences between the Department's results and our own, the Company's analysis showed that due to a longer operating life and flexible in-service date, Black Dog Unit 6 offers significant savings for customers in comparison to other proposals. Dr. Rakow's First Round analysis confirmed this finding.[1] But in the Second Round analysis the results flipped,[2] and the Department ends up recommending Calpine's Mankato Expansion over Black Dog 6. Second, the Company's analysis showed that Calpine's Mankato Expansion and Invenergy's Cannon Falls project costs are closely matched, while the Department's analysis shows a considerable gap between the two projects.

A. Department Analysis of Black Dog Unit 6

Q. WHY SHOULD BLACK DOG 6 BE CHOSEN UNDER ANY RESOURCE NEED ASSESSMENT?

A. As demonstrated in my direct testimony, Black Dog 6 provides long-term cost benefits compared to all of the other proposals. These benefits are not reflected in the Department's analysis.

[1] See Rakow Direct, Attachment SR-4a at pages 9-10.

[2] See Rakow Direct, Attachment SR-5A at page 1.

Q. PLEASE ELABORATE ON THE BENEFITS OF BLACK DOG 6 WHICH WERE NOT REFLECTED IN THE DEPARTMENT'S ANALYSIS.

A. Based on review of the Department's analysis, I have identified two instances where their Strategist model is undervaluing the Black Dog 6 project:

1) from 2019 through 2036, the Department's decision not to 'lock' the model's long-term expansion plan resulted in Strategist adding additional costs to the project; and
2) the 2013-2036 simulation period chosen by the Department does not capture the long term benefits of the project. Worse yet, the "end effects" adjustment that was supposed to represent Black Dog 6's long-term savings actually resulted in a $10 million penalty for the project.

Q. PLEASE EXPLAIN THE BENEFITS OF BLACK DOG 6 FROM 2019 THROUGH 2036.

A. Through lower annual fixed costs, our Black Dog 6 unit offers considerable cost savings in comparison to Calpine's Mankato Expansion. From 2019 through 2036, the average annual fixed costs of Black Dog are **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, while the fixed costs of Calpine over the same period are **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. While Calpine's higher efficiency does provide additional savings through lower fuel costs, these savings are not enough to offset the higher fixed costs.

Q. IF BLACK DOG HAS LOWER ANNUAL COSTS FROM 2019 THROUGH 2036, WHY DOES THE DEPARTMENT'S ANALYSIS SHOW CALPINE'S PROJECT HAS LOWER

COSTS?

A. After reviewing the Department's analysis, I have determined that its modeling of the expansion plan in Strategist inadvertently added costs to our proposal which in my opinion were not appropriate. As explained by Dr. Rakow in his direct testimony, the Department did not 'lock' the long-term expansion plan in their model.[3] This means that for each bid portfolio studied, Strategist created a different portfolio of resources for the period 2020 through 2036. The result is that the Department's results are not a direct comparison between bid proposals, but rather a comparison of the bids plus the cost of some generic natural gas plants that were added by Strategist.

Our Strategist analysis locked the long-term expansion plan, and thus created a direct comparison between bid costs. The results of our model show that the net cost of Black Dog 6 is lower than the net cost of Calpine's proposal in almost every year for the period 2019 through 2036, as shown in Figure 1 below. By 2036, Black Dog 6 creates a net PVSC savings of $20 million in comparison to Calpine's project.

Q. PLEASE ELABORATE ON THE IMPACTS OF THE DEPARTMENT'S DECISION TO ONLY RUN STRATEGIST THROUGH 2036.

A. The proposals from Calpine, Invenergy, and Geronimo are all for 20-year PPAs, expiring by spring of 2037. However, the Company's proposed Black Dog Unit 6 and Red River Valley Units 1 and 2 have an expected operating life of 35 years, retiring in the 2050 to 2052 timeframe. Because the Department limited its Strategist simulations to the 2013 to 2036 period only,

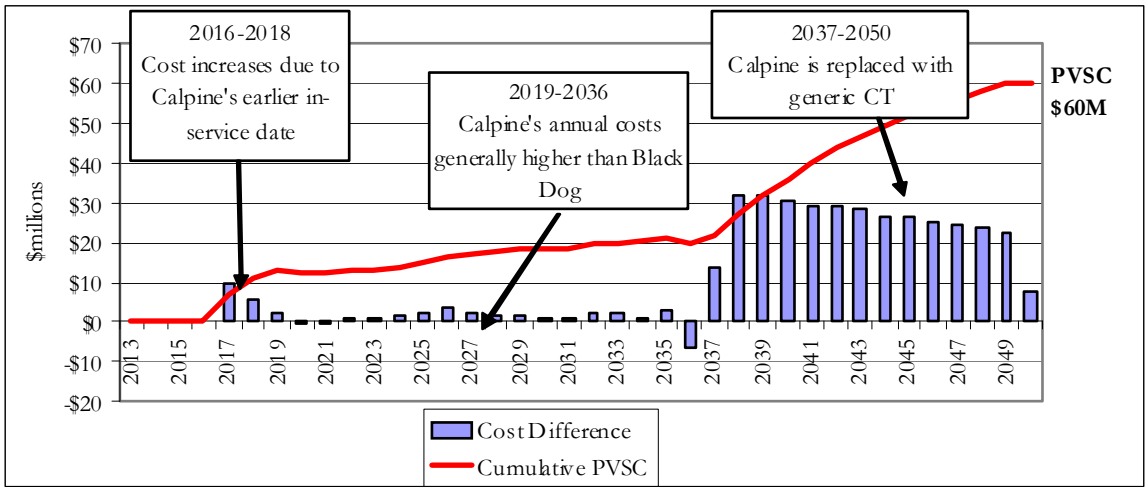
[3] See Rakow Direct at pages 31-32.

they do not capture the long-term benefits identified in the Company's analysis. Dr. Rakow acknowledges this impact at page 28, lines 8 and 9, of his direct testimony:

> *"However such an end date [(2036)], even with end effects, likely does not account for the full value of Xcel's bids…"*

To illustrate the impact of the shorter simulation period, I compare the annual cost difference between Calpine and Black Dog 6 from the Company's Strategist analysis to the Strategist analysis of the Department. Figure 1 below illustrates the Company's Strategist results, showing that after the savings realized as a result of Black Dog's later in-service date, the two projects have only small cost differences through 2036. Then in 2037, the Calpine project must be replaced by a new combustion turbine at the forecasted 2037 market price. This will be significantly more expensive than the cost of the depreciated Black Dog unit at that time, and thus Black Dog 6 offers significant cost savings in the 2037 to 2050 time period.

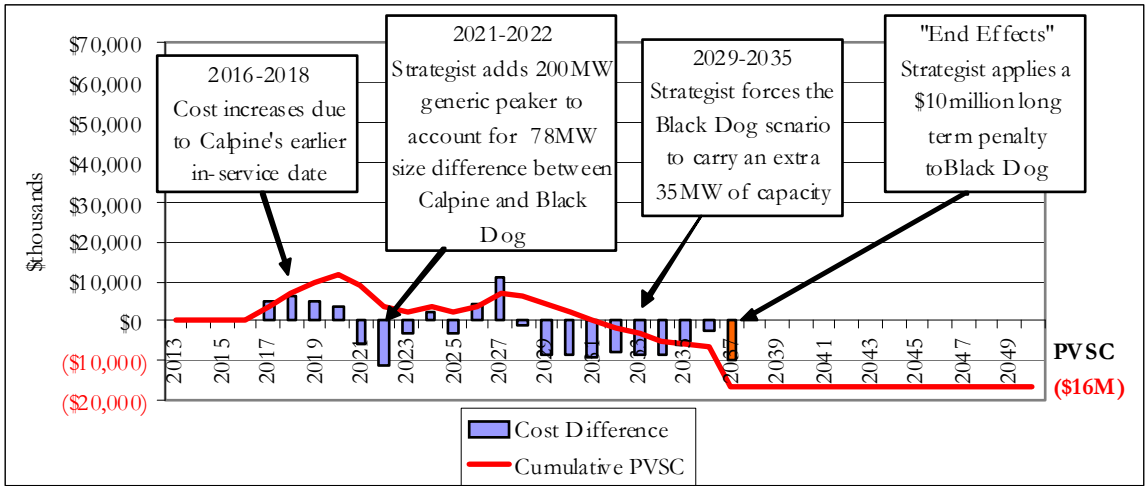
Figure 1 - Calpine Mankato vs. Black Dog 6
Xcel Energy Strategist Modeling



(Plan 56: Invenergy Cannon Falls + Calpine Mankato vs. Plan 1: Invenergy Cannon Falls + Black Dog 6)

Figure 2 below shows the results of the Department's Strategist modeling which is limited to the 2013 to 2036 time period. Its model begins with a similar pattern of cost savings, but then there are periodic jumps and swings in the net costs and net benefits of Black Dog depending on when Strategist chooses to add generic power plants. This is a result of the Department not locking the expansion plan in Strategist. Then at the end of the simulation period, Strategist adds a $10 million "end effects" penalty to the Black Dog scenario. The "end effects" adjustment is a lump sum estimate of the long-term cost of the unit after the year 2036. This adjustment is a short-cut alternative to actually modeling the cost of the unit to the end of its life as our Strategist analysis did. Based on the Company's decades-long experience with Strategist modeling, we have found the "end effects" adjustment is very unreliable. Much more accurate results are achieved by modeling the full lifetime of the resource being evaluated.

Figure 2 - Calpine Mankato vs. Black Dog 6
Department Strategist Modeling



(Master Scenario 1 - ICT1 CCC1 vs. BD618 ICT1)

Q. PLEASE EXPLAIN HOW THE 2037 TO 2050 BENEFIT OF BLACK DOG 6 PRESENTED IN FIGURE 1 CAN BE SO LARGE.

A. The net benefit is based on the cost difference between Black Dog 6 in the future and the cost to build a new plant to replace the retiring Calpine contract. A CC plant that would cost $120 million today will cost $193 million in 2037 using a simple inflation rate of 2 percent. By that time the book value of Black Dog 6 will be largely depreciated so its cost will be well below the market price for capacity at that time. On page 28, line 6 of my direct testimony I present a graph that shows that the costs of Black Dog 6 in 2037 will be 40 percent lower than its first year costs due the impacts of book depreciation.

Q. CAN YOU PROVIDE EXAMPLES OF THE ACTUAL LONG TERM BENEFITS OF OWNED UNITS?

A. Yes. The cost of the natural gas proposals in this docket range from **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. This can be considered the current market price for capacity. In comparison, some of the older plants we own have capacity prices as low as $0.15/kW-mo. This is a very large benefit for our customers. We expect that towards the end of its operating life, Black Dog 6 will have similar benefits. To provide context, Table 1 below summarizes the average cost of some of our older peaking facilities for comparison.

Table 1 – Approximate Cost of Xcel Energy Peaking Units (per kW/mo)

	Inverhills 1-6	Blue Lake 1-4	Key City 2-4	Granite City 1-4	Wheaton 1-6
In-Service Year	1972	1974	1970	1969	1973/74
Max Capacity	371 MW	194 MW	41 MW	64 MW	383 MW
Average Capacity Cost	**$0.63**	**$0.15**	**$0.13**	**$1.13**	**$0.79**

Q. EARLIER YOU MENTIONED THAT THE RESULTS OF THE DEPARTMENT'S ANALYSIS OF BLACK DOG 6 CHANGED BETWEEN THE FIRST ROUND AND SECOND ROUND. PLEASE ELABORATE.

A. Department Attachment SR-4a at pages 9 and 10 shows the First Round results for the Master Scenario 3, which identifies Black Dog 6 with an in-service date of 2017 (BD617) as being lower in cost than Calpine Mankato (CCC1). Later in his testimony, Dr. Rakow presents the results of the

Department's Second Round analysis, which he states are based on the Master Scenario 3, which is at page 1 of Attachment SR-5A of his direct testimony. These Second Round results show Black Dog 6 being higher in cost than Calpine, and it is these results on which Dr. Rakow bases his resource selection recommendation. Table 2 below summarizes the different cost results for Black Dog 6 and Calpine in the two rounds of the Department's Strategist analysis.

Table 2 – Department Evaluation of Black Dog 6 and Calpine

	Master Scenario 3 PVSC Results ($000)	
	Round 1	**Round 2**
Black Dog 6 – 2017 (BD617)	$41,410,496	$41,326,470
Calpine Mankato (CCC1)	$41,419,740	$41,315,664
Black Dog +/-	($9,244)	$10,806

Dr. Rakow provides no explanation why the two simulations, purportedly based on the same input assumptions, would be so dramatically different. While we obtained the Strategist files from the Department, we were unable to replicate the Department's results, shown in Table 2 above.

Q. PLEASE SUMMARIZE THE COMPANY'S POSITION REGARDING BLACK DOG 6.

A. We believe that the analysis conducted by the Company more accurately reflects the benefits of Black Dog 6 by simulating its costs over the full life-time of the project. Our analysis demonstrates that Black Dog 6 is the least cost resource among the proposals in this proceeding and should be selected under any resource need assessment. Compared to the Calpine proposal, our

project creates benefits though a flexible in-service date, considerably lower annual fixed costs than Calpine from 2019 through 2036, and the long-term savings of a Company-owned project that cannot be offered by 20-year PPAs.

B. Department Analysis of Invenergy Cannon Falls

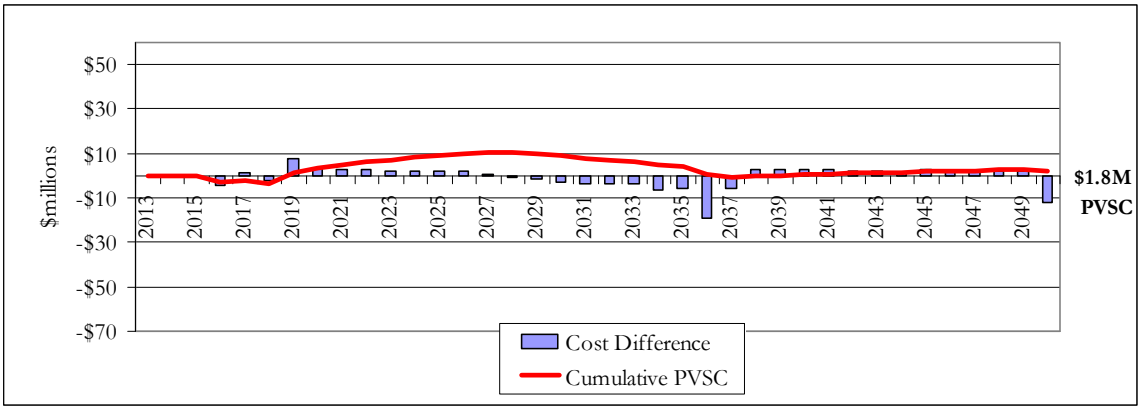
Q. YOU NOTED THAT THE COMPANY'S ANALYSIS SHOWED THAT CALPINE'S MANKATO EXPANSION AND INVENERGY'S CANNON FALLS PROJECT COSTS ARE CLOSELY MATCHED, WHILE THE DEPARTMENT'S ANALYSIS SHOWS A CONSIDERABLE GAP BETWEEN THE TWO PROJECTS. DO YOU HAVE AN EXPLANATION FOR THESE DIFFERENT RESULTS?

A. Yes, I believe so. Over the first few years of the Strategist simulations, the Department's and the Company's results are very similar, but starting in 2022 the Department's model starts changing the underlying expansion by moving the in-service dates of generic power plants to account for capacity differences among the projects proposed for selection. This is the result of the Department deciding not to 'lock' its expansion plan. In the Company's analysis, however, the expansion plan is locked so that it is the same across all scenarios, and capacity credits are used to address the capacity differences between the proposed projects.

Although our methodologies differ, our results are reasonably similar through 2036. However, at the end of 2036, the Department's model applies a $50 million "end effects" penalty to the Invenergy bid. As I mentioned in my discussion of the Department's modeling of Black Dog 6, the "end effects" adjustment attempts to represent an estimate of the long-term cost of a

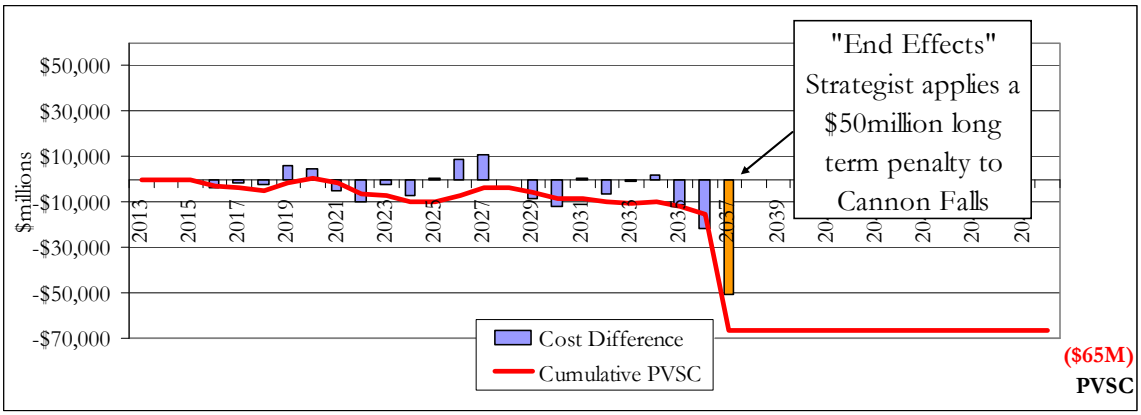
resource instead of modeling the long-term cost. The magnitude of this "end effects" adjustment is very non-intuitive. Figure 3 below shows the Company's modeled cost of Invenergy's Cannon Falls proposal while Figure 4 shows the Department's modeled cost of the proposal. Conceptually, there should not be so large a cost difference between the two since each retires in approximately the same time frame.

Figure 3 - Calpine Mankato vs Invenergy Cannon Falls
Xcel Energy Strategist Modeling



(Plan 1: Invenergy Cannon Falls + Black Dog 6 vs. Plan 2: Calpine Mankato + Black Dog 6)

Figure 4 - Calpine Mankato vs Invenergy Cannon Falls
Department Strategist Modeling



(Master Scenario 1 - BD619 CCC1 vs. BD618 ICT1)

Eliminating the apparent disproportionate impact of the "end effects" adjustment in the Department's Strategist analysis of Invenergy Cannon Falls would be consistent with the Company's analysis showing that the least cost potential of Cannon Falls in combination with Black Dog 6 is comparable to the combination of Calpine with Black Dog 6. We therefore continue to recommend that both Calpine Mankato and Invenergy Cannon Falls be selected by the Commission to move forward to the PPA negotiation stage of these proceedings.

III. CALPINE LEVELIZED COST OF ENERGY ANALYSIS

Q. WHAT IS YOUR ASSESSMENT OF THE LEVELIZED COST OF ENERGY ANALYSIS PRESENTED BY CALPINE WITNESS MR. HIBBARD?

A. A LCOE analysis only looks at costs, and is only appropriately used when comparing very similar resources of the same type where cost is the principal, if not only, distinguishing factor between the resources. In this proceeding,

however, we have a great variety of resources: peaking and intermediate resources, dispatchable and nondispatchable resources, and natural gas, solar, and short-term "paper" capacity resources. LCOE simply does not work in a situation like this. In this situation, a proper analysis must examine both the costs of the proposed resources and their widely varying benefits, which is what Strategist does.

The limitations of the LCOE approach were recently addressed by the Energy Information Administration (EIA), which annually publishes levelized cost estimates for various generation resources for use in its Annual Energy Outlook. This year's EIA analysis included the following cautionary note regarding the use of levelized costs:[4]

> Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of the levelized cost of electricity across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments, which may then be divided by average annual output of the project to develop a figure that expresses the "levelized" avoided cost of the project. This levelized avoided cost may then be compared to the levelized cost of the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's levelized avoided cost to

[4] http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf, last viewed on October 17, 2013.

> its levelized project cost may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than for simple levelized costs, because they require tools to simulate the operation of the power system with and without any project under consideration.

Q. DO YOU HAVE AN EXAMPLE OF HOW MR. HIBBARD'S LCOE IS PROBLEMATIC WHEN ASSESSING THE COST-EFFECTIVENESS OF DIFFERENT RESOURCES, AS THE EIA CAUTIONS?

A. Yes. For example, Mr. Hibbard contends that in order not to "punish" Calpine's CC unit for being a more expensive and cleaner generation resource (pages 29-30 of Hibbard Direct), $15 million of SCR technology costs should be added to each CT proposal so that their emissions are as low as Calpine's proposal (page 11 of Hibbard Direct). First, as Company witness Mr. Gregory Ford explains in his rebuttal, our proposed CT units will meet all current applicable environmental standards for emissions just as Calpine's proposed unit does. Adding millions of dollars in costs to our units so that they reach emission levels that they are not required to meet does nothing more than arbitrarily increase the capital costs of our CTs in relation to the more expensive capital costs of a CC unit.

Second, Mr. Hibbard's SCR adjustment does not address the real issue that he has identified: what is the value of any avoided emissions that would be realized if Calpine's CC project is added to our system rather than our proposed CTs? The Strategist simulations performed by the Company and the Department answer that question. The Strategist modeling presented in this proceeding has determined the impact each project has on our entire system's emissions over the life of the project. The model then assigns the

Commission's annually updated environmental externality values to establish the cost incurred or avoided as a result of the project being added to our system. Strategist thus directly calculates the value of Calpine's avoided emissions, while Calpine's LCOE analysis assigns an additional, unwarranted capital cost to our CTs because its cost-only approach cannot properly value the avoided emission costs of the Calpine project.

IV. BENEFITS OF FIRM VS. INTERRUPTIBLE NATURAL GAS SUPPLY

Q. PLEASE SUMMARIZE THE REQUEST OF DEPARTMENT WITNESS MR. SHAH REGARDING NATURAL GAS SUPPLY.

A. In his conclusion and recommendation, Mr. Shah requests that the Company address in rebuttal:

1. The use of current interstate pipelines in relation to the proposals in this proceeding;
2. The benefits and costs of firm vs interruptible natural gas; and
3. The operational impact of firm vs interruptible natural gas supply and its impact on the reliability impact to our customers.

Q. HOW WILL THE COMPANY USE ITS CURRENT INTERSTATE PIPELINE CONTRACTS IN RELATION TO THE PROPOSALS IN THIS PROCEEDING?

A. We reviewed a variety of options to achieve an appropriate balance between reliability and cost. The decision to supply a power plant with firm or interruptible transportation service should be made on a case-by-case basis applying the unique circumstances of that plant and the upstream interstate transporter's operational and market conditions. As noted previously, the Company expects to use firm transport contracts to serve the Black Dog and

Mankato plants if our Black Dog 6 and the Calpine's Mankato Expansion projects are selected by the Commission. As detailed in the Company's supplemental response to Department Information Request No. 42, included as Schedule 1 to my rebuttal testimony, we expect to use a combination of existing and new firm contracts.

The Mankato plant would be served by a new, firm transportation contract. The Black Dog plant would be served using existing firm contracts with a small amount of new, firm additional transport capacity from Northern Natural Gas (NNG). In both cases, the Company modeled the transportation supply options as reported in DOC-042. The Company plans to use firm transport because of the need for a high level of certainty of service and a pressure guarantee from NNG to ensure plant operations. We also plan to use firm gas transport because the plants are located within an area of NNG's system that is generally fully subscribed. An added benefit is that the firm transport service for both the Mankato and Black Dog locations may be acquired at a prearranged discounted rate from NNG, resulting in comparatively lower costs for the service.

Q. WHAT ARE SOME OF THE COSTS AND BENEFITS OF FIRM VERSUS INTERUPTABLE NATURAL GAS SUPPLY?

A. Firm service is certain; it will provide reliable fuel supply to a plant every day except for the rare occurrence of a force majeure or scheduled maintenance event. Pipeline companies do everything in their power to minimize the impact of maintenance on firm customers. However, during these infrequent events, firm customers are reimbursed for the lack of service. The downside

of firm service is the cost. Firm service contracts can be expensive and the monthly charges are paid whether the delivery service is used or not.

Interruptible service provides less certainty but can be less expensive. On days when the demand for natural gas supply is high, interruptible customers are not likely to receive service to their locations. However interruptible customers are only charged on the quantities delivered to their site. For a peaking resource that only operates a few times a year, usually to meet peak customer demand in the summer, the use of an interruptible natural gas supply can deliver significant costs savings without a significant impact on reliability, so long as the unit can operate on back-up fuel oil or there are other system units available to meet the demand.

Q. WHAT ARE SOME OF THE COSTS AND BENEFITS OF FIRM VERSUS INTERRUPTIBLE NATURAL GAS SUPPLY WITH RESPECT TO INVENERGY'S CANNON FALLS PROJECT?

A. To evaluate the costs and benefits of interruptible natural gas supply to the Cannon Falls Expansion, we re-ran the Strategist simulation for Plan 1, which includes Invenergy's Cannon Falls proposal plus the Company's Black Dog 6 project.

The modeling made natural gas unavailable to the Cannon Falls project from November through February. This reflects an assumption that natural gas is completely unavailable at the site and there is no additional back-up fuel oil to serve the new unit. The result of the simulation was that even in the unlikely event Cannon Falls cannot operate at all from November through February,

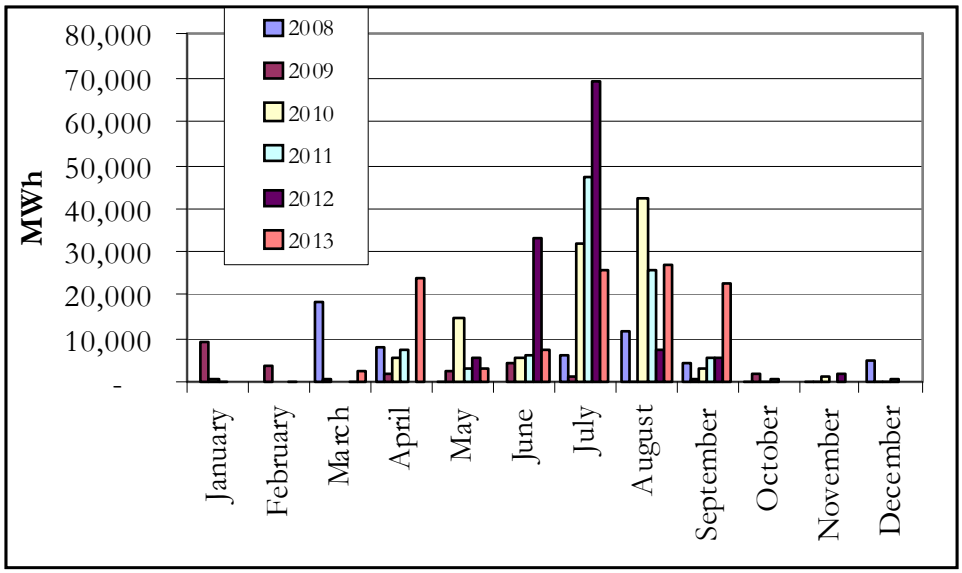
the project's cost effectiveness does not change. Table 3 shows that the PVSC of Plan 1 increases by less than $1 million.

Table 3 – Strategist PVSC Results
Invenergy Cannon Falls Unavailable November – February

		2013-2050 PVSC $millions	
	Selected Bids	Wishart Direct Testimony	Cannon Falls Unavailable Nov - Feb
Plan 1	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	$45,366	$45,367
Plan 2	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	$45,368	$45,368
	Net Difference	**$1.8**	**$1.5**

The results of this simulation are not surprising. Our customers' demand is significantly lower in the winter so our peaking resources very infrequently operate during the winter season. Figure 5 shows monthly generation at the existing Cannon Falls site since its commercial operation date of 2008.

Figure 5 – Cannon Falls Monthly Generation



Q. WHAT WOULD BE THE COST OF THE CANNON FALLS PROJECT IF FIRM NATUAL GAS SUPPLY WERE PROCURED FOR THE PROJECT?

A. Our supplemental response to Department Information Request No. 42, which is Schedule 1 of my rebuttal testimony, provides our cost estimates for firm and interruptible service for all the natural gas projects proposed in this docket. To test the cost impacts of firm natural gas supply at Cannon Falls, we again re-ran the Plan 1 Strategist simulations, but this time with year-round firm natural gas supply. Table 4 shows that the total PVSC for Plan 1 increases by about $30 million with the addition of firm gas at Cannon Falls, making it uncompetitive with the Calpine proposal.

Table 4
PVSC Impact of Firm Gas at Cannon Falls

	Selected Bids	2013-2050 PVSC $millions Wishart Direct Testimony	Cannon Falls Unavailable Nov - Feb
Plan 1	Invenergy Cannon Falls - 2016 - 150MW Black Dog 6 - 2018 - 208MW	$45,366	$45,397
Plan 2	Calpine Mankato - 2017 - 278MW Black Dog 6 - 2019 - 208MW	$45,368	$45,368
	Net Difference	**$1.8**	**-$29.3**

Q. WHAT ARE THE EXPECTED OPERATIONAL AND RELIABILITY IMPACTS OF INTERRUPTABLE SERVICE AT CANNON FALLS?

A. The simulations of Plan 1 with Cannon Falls unavailable from November though February showed that generation from other peaking resources with firm gas supply would increase from 900 GWh to 903 GWh. In the context of our total natural gas generation portfolio, this is a very small change.

To gauge the impact on reliability, I utilized our winter loads and resources (L&R) table. Just like our summer L&R that I presented in my direct testimony, the winter L&R shows how much excess generation capacity we will have over and above our customers' forecasted peak winter demand. Table 5 below shows that we currently have a very large amount of excess capacity to meet our customer's peak demand in the winter. In 2019 our total winter reserve margin is forecasted to be 22 percent, while MISO's minimum required reserve margin is 3.8 percent.

Table 5 – Xcel Energy Winter Loads and Resources

	2017	2018	2019
Peak	6,606	6,671	6,733
RM%	3.8%	3.8%	3.8%
Total Obligation	**6,857**	**6,924**	**6,988**
Resources			
Coal	2,367	2,367	2,367
Nuclear	1,708	1,610	1,610
Gas	3,547	3,533	3,533
Wind, Hydro, Bio	573	521	515
Solar	49	66	83
Load Management	379	379	379
Total Resources	**8,624**	**8,477**	**8,487**
Long (Short)	**1,767**	**1,553**	**1,499**
Reserve %	27%	23%	22%

V. OTHER STRATEGIST ANALYSIS ISSUES

Q. INVENERGY WITNESS MR. DANIEL EWAN IDENTIFIES A NUMBER OF ISSUES RELATED TO STRATEGIST AT PAGES 15-16 OF HIS DIRECT TESTIMONY. WHAT IS YOUR RESPONSE?

A. Mr. Ewan objects to Strategist's evaluation of a resource's costs over its expected life, that it compares resource options on a PVSC basis which results in the timing of the resources being critical, and that it is not clear how Strategist can address the costs and benefits of including or not including dual fuel capabilities in the proposals like Invenergy's. Addressing this last issue first, we did model the costs and benefits of using an interruptible gas supply for Invenergy's Cannon Falls project, which I discuss in the preceding section of my rebuttal testimony. Assuming the highly unlikely scenario of the gas supply to Cannon Falls being interrupted for the period November through

February and its back-up fuel oil being unavailable, Strategist showed the project's cost effectiveness would be essentially unchanged.

Mr. Ewan's concerns with respect to evaluating a project's costs over its life and the use of net present value in the evaluation of proposals do not seem justified to me. An evaluation showing that the costs of a proposed Company-owned project over its lifetime are less than the costs of a proposed PPA that must be extended through the addition of plant, or another PPA to cover the same time period, does not "punish" the PPA proposal. It simply shows that the owned project is more cost-effective in the long run. With respect to the timing of the various proposals submitted for the Commission's consideration, this is a critical issue because we do not want to impose the costs of additional resources on our customers before they are needed.

Q. DID THE COMPANY'S STRATEGIST ANALYSIS ADDRESS THE MODELING ISSUES THAT GERONIMO WITNESS MS. ELIZABETH ENGELKING IDENTIFIED AT PAGE 6 OF HER DIRECT TESTIMONY?

A. Our initial Strategist analysis did not address Ms. Engelking's request that Geronimo's proposal be modeled to apply towards meeting Minnesota's new Solar Energy Standards mandate. I explained at page 36 of my direct testimony that we did not do so because there are no other solar proposals in this docket, so the Company cannot assess the reasonableness of Geronimo's proposed pricing relative to other solar projects that could also help the Company meet its solar energy goals. However, the pricing of the generic solar used in our Strategist modeling to comply with the solar energy standard was priced below the Geronimo proposal. If the generic solar had been

removed from the model, Geronimo's proposal would have contributed to meeting the solar energy standard, but would have resulted in a larger PVSC impact for Geronimo because the model would be replacing cheaper solar with more expensive solar.

Ms. Engelking also stated in her direct estimony that Geronimo would be examining how our modeling incorporated the environmental costs of the various alternatives and whether it would include the savings associated with Geronimo's line loss reductions. As I discussed earlier, our Strategist analysis evaluated the environmental costs of the various proposals, and while we did not include line loss savings in our Strategist analysis, we did calculate what those savings would be based on Geronimo's estimate of its energy and capacity benefits. As explained at page 36 of my direct testimony, the savings were not enough to make Geronimo's project cost effective.

Q. DID THE COMPANY'S STRATEGIST ANALYSIS EVALUATE THE BENEFIT OF GREAT RIVER ENERGY'S (GRE) PROPOSAL OF TWO DIFFERENT CAPACITY LEVELS TO ALLOW THE COMPANY TO DEFER ADDING NEW CAPACITY RESOURCES WITHIN THE 2017 TO 2019 TIME PERIOD, AS NOTED BY GRE WITNESS MR. STAN SELANDER AT PAGE 3 OF HIS DIRECT TESTIMONY?

A. Yes. I addressed this issue at page 33 of my direct testimony, explaining that our Strategist analysis showed the total cost of the GRE contract is larger than the savings derived from delaying new construction during the 2018 to 2019 time period. Specifically, the cost of the GRE contract is greater than the savings realized from shifting the in-service year of Black Dog 6, which is the least cost proposal in this proceeding, from 2018 to 2019.

Q. CAN YOU SUMMARIZE THE COMPANY'S RESOURCE SELECTION RECOMMENDATIONS FOR THE COMMISSION?

A. We recommend that Black Dog 6 in combination with Calpine Mankato or Invenergy Cannon Falls be selected to meet the Company's resource need, and that both the Mankato and Cannon Falls proposals should go to the PPA negotiation stage to establish which one is more beneficial to our customers. We also recommend that under any resource need assessment, Black Dog 6 should be selected because it is the least cost resource option among the proposals in this proceeding. We also believe that given the current uncertainty over our resource need, the Commission should direct the Company to provide updates on its resource need assessments in the fall of 2014 and 2015. Consistent with this, we recommend that the Commission direct that the PPA negotiations address the viability of delay and/or cancellation options for the Calpine and Invenergy projects.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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

Xcel Energy			
Docket No.:	E002/CN-12-1240		
Response To:	Department of Commerce	Information Request No.	042
Requestor:	Sachin Shah & Steve Rakow		
Date Received:	June 28, 2013	**SUPPLEMENT**	

Question:

Subject: Information provided by Xcel Energy -- Northern States Power Company, A Minnesota Corporation (Xcel Energy, NSP or Company) in its *Petition to the Minnesota Public Utilities Commission Seeking Approval For A Competitive Resource Acquisition Proposal and For A Certificate of Need:*

Subject: Information provided by Invenergy Thermal Development LLC in the bids: *Cannon Falls Peaking Expansion: Goodhue County, Minnesota* and *Hampton Energy Center: Dakota County, Minnesota* (dated April 15, 2013 and May 9, 2013).

Subject: Information provided by Calpine Corporation and its affiliate Mankato Energy Center, LLC in the bid: *Calpine's Mankato Energy Center Expansion Proposal* (dated April 15, 2013 and May 8, 2013).

In Docket No. E002/CN-12-1240, the Company in its Certificate of Need (CN) filing, indicates the use of natural gas prices by existing generating units in its strategist base case.

On page 4 of the *Cannon Falls Peaking Expansion Bid* Invenergy in part states the following:

> … Invenergy proposes to develop the Cannon Falls Peaking Expansion and sell the capacity and energy to NSP with terms and conditions substantially similar to the existing Power Purchase Agreement between Cannon Falls and NSP dated April 1, 2005.

On page 4 of the *Hampton Energy Center Bid* Invenergy in part states the following:

> … Invenergy proposes to develop the Hampton Energy Center with a design and configuration that is very similar to Invenergy's existing Cannon Falls Facility this is located in Goodhue County. Furthermore, Invenergy proposes to sell the capacity and energy to NSP with terms and conditions substantially similar to the

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existing Power Purchase Agreement between Cannon Falls and NSP dated April 1, 2005.

On page 4 of the *Calpine's Mankato Energy Center Expansion Proposal* Calpine in part states the following:

> Consistent with the Commission's directive that parties be held to the cost information provided in their bids,4 the specific pricing, terms and conditions of Calpine's Proposal represent a fixed-price indicative offer5 with long-term performance guaranties wherein Calpine will assume the construction, delivery date and long term operating risk of the Mankato Expansion.

---

5. Subject to any material changes in project timing and/or scope required by the Commission or identified during final tolling agreement negotiations. Proposed pricing assumes a 2017 commercial operation date.

In Appendix A, on page 3 of the *Calpine's Mankato Energy Center Expansion Proposal* Calpine in part states the following:

> Calpine intends to follow the PPA structure used in the Purchased Power Agreement between MEC and Northern States Power Company executed on March 11, 2004 ("MEC PPA") for expediency, cost effectiveness and negotiating efficiency.

1. It is the Department's understanding, based on the above references, that Invenergy's *Bids* and Calpine's *Proposal* assume that Xcel would pay all of the fuel costs of purchasing and delivering natural gas to Cannon Falls facility's and Mankato Energy Center's points of delivery, respectively. Is this understanding correct?

2. If the answer to part (1) is in the affirmative, then please fully explain in detail if the natural gas fuel prices contained in Xcel's strategist base case for the existing Cannon Falls facility and the Mankato Energy Center would be appropriate to use in comparing the *Bids* and *Proposal* of Invenergy and Calpine, respectively, given the above references.

3. Please fully explain the type of natural gas being provided to the existing facilities at Cannon Falls and Mankato Energy Center (i.e., Firm, Interruptible, or a combination of Firm and Interruptible).

4. Please fully explain and identify the associated natural gas commodity costs in parts (2) and (3) above.

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5. Please fully explain and identify in detail the amount and type of interstate pipeline transportation and fixed reservation (demand) costs that are included in parts (2) and (3) above.

6. Please fully explain and identify the amount, if any, of local pipeline distribution service costs that are included in parts (2) and (3) above.

Where applicable for any and all parts above, please provide the requested data in a Microsoft Excel executable format with all links and formulae intact. If any of these links target an outside file, please provide all such additional files.

In addition, please provide your response in both a Microsoft Word and Adobe PDF format.

In addition, whenever acronyms are used in the data given in your response above, please provide an explanation of all acronyms used AND also provide a brief but complete explanation of the source of each data series that is provided.

If this information has already been provided in written testimony, filing, or in response to an earlier Department of Commerce (DOC) information request, please identify the specific testimony, and/or filing cite(s) or DOC information request number(s).

Response:

1. Yes, the bidders are proposing that Xcel be responsible for the costs of fuel purchasing and delivery for these projects and we are currently developing estimates of those costs. However, the bidder is responsible for installing and maintaining the incremental back-up fuel oil facilities.

2. No, it would not be appropriate to use the costs currently contained in Xcel's strategist base case to evaluate the *Bids* and *Proposal* of Invenergy and Calpine. The cost contained in the Strategist base case are natural gas commodity costs, plus the variable transport costs to deliver gas to the existing facilities based on the existing transport agreements. Although the natural gas commodity costs are likely to be representative of the supply cost, it is likely that the variable transport charges will be different. In addition, the Strategist base case does not include the annual fixed charges associated with fuel delivery at those sites.

   Both variable transport cost and annual fixed charges for fuel supply will be dependent on whether or not firm or interruptible fuel supply will be used at

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the facility. We are currently developing these estimates and propose to provide these costs in a supplemental response in approximately three weeks (Aug 9th). If the estimates are completed sooner than expected we will supply them as soon as they are available.

3. NSP uses a combination of firm and interruptible upstream transportation service to deliver firm gas supplies to Cannon Falls and Mankato, in addition to the back-up fuel oil. Gas supply is purchased at Ventura, Iowa on Northern Natural Gas (NNG) and then transported by NNG to the plants. Mankato is directly connected to NNG via a plant line. Cannon Falls is served from NNG via Greater Minnesota Gas (an intrastate pipeline).

4. Please see Attachment A for the associated natural gas commodity costs.

5. Attachment A also includes the volumetric transportation charges currently being used in Strategist for the two existing plants. The Strategist base case does not include the specific annual fixed charges (reservation / demand charge) associated with fuel delivery at those sites.

Please note that portions of Attachment A are marked "Non-Public" as it contains information the Company considers to be trade secret as defined by Minn. Stat. § 13.37(1)(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by other parties, who could obtain economic value from its disclosure or use. Thus, Xcel Energy maintains this information as trade secret.

SUPPLEMENT:

5. Please see Attachment B for details regarding the estimated upstream pipeline transportation costs to provide fuel to the Mankato, Hampton, and Cannon Falls plants. All three plants would be sited in an area where the interstate natural gas pipeline is essentially fully subscribed, requiring construction of additional pipeline facilities to make the plants' fuel supply highly reliable. Mankato would be served by transportation service from Northern Natural Gas. Since Mankato is proposed as a combined cycle, intermediate load facility, it will require firm gas transportation on a year-round basis.

Hampton and Cannon Falls would be served by transportation from Northern Natural Gas and Greater Minnesota Transmission. Attachment B shows estimated costs to provide firm year-round transportation service to Hampton and Cannon Falls to make the plants' fuel supply highly reliable. In the alternative, if the

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Commission elects less reliable service for these two plants, Attachment B separately shows costs for interruptible transportation service to the plants. Using interruptible service, the Commission should expect the plants to have regular fuel supply in the summer months (April through October) except during periods of pipeline maintenance and emergency operations. However, in the winter months (November through March), the Commission should expect the plants to be unable to operate on most cold winter days due to interruption of gas transportation services on Northern Natural Gas. The interruptible service option is cheaper for low-load factor peaker plants; however, the plants will not be available on many winter days.

6. There are no local distribution charges for Mankato in NSP's Strategist base case; however, Cannon Falls and Hampton rely on Greater Minnesota Transmission as described in (3) above. The Greater Minnesota Transmission system, which is considered an intrastate facility, would also be used to serve the Hampton and Cannon Falls plants. Those costs are detailed in Attachment B to Response 5 above. There are no other distribution charges anticipated for these plants.

Preparer:	Curt Dallinger/Steve Wishart	
Title:	Director/Director	
Department:	Gas Planning/Resource Planning	
Telephone:	303-571-2784/612-330-6128	
Date:	July 23, 2013	**SUPPLEMENT: August 15, 2013**

Northern States Power Company

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Strategist natural gas fuel prices vary monthly. Strategist fuel prices are input as an annual average which is then adjusted by a factor for monthly seasonality. The monthly Cannon Falls cost (Column H) is annually averaged (Column M). To calculate the seasonality factor, the monthly cost (Column H) is divided by the corresponding annual average (Column M) for the years 2012 through 2020. The seasonality for years 2021 through 2050 in the analysis below uses the 2021 seasonality.

	Cannon Falls Yearly Avg ($/mmBtu)		
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2012			Avg
2013		1	Jan
2014		2	Feb
2015		3	Mar
2016		4	Apr
2017		5	May
2018		6	Jun
2019		7	Jul
2020		8	Aug
2021		9	Sep
2022		10	Oct
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… TRADE SECRET DATA ENDS]

Cannon Falls Total Gas Commodity Cost = Ventura Hub Price + (Fuel Percentage * Ventura Hub Price) + Interruptible Rate (Winter Only) + Firm Rate (Summer Only) + Intrastate Pipeline Commodity Rate

Cannon Falls is subject to an Intrastate Pipeline Commodity Rate for intermediate pipeline connecting Northern Natural Gas to Plant.

Cannon Falls

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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Northern States Power Company

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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Northern States Power Company

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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Northern States Power Company

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	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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Northern States Power Company

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Cannon Falls

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Interruptible Rate - Northern Natural Gas ($/mmBtu)	Firm Rate - Northern Natural Gas ($/mmBtu)	Intrastate Pipeline Commodity ($/mmBtu)	Cannon Falls Total Gas Commodity Cost ($/mmBtu)	Strategist Cannon Falls Total Gas Commodity Cost ($/mmBtu)
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Oct-50							
Nov-50							
Dec-50							

TRADE SECRET DATA ENDS}

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Northern States Power Company

Strategist natural gas fuel prices vary monthly. Strategist fuel prices are input as an annual average which is then adjusted by a factor for monthly seasonality. Mankato seasonality is assumed to follow the seasonality of the forecast of Ventura Hub Price. The monthly Ventura Hub Price (Column C) is annually averaged (Column L). To calculate the seasonality factor, the monthly cost (Column C) is divided by the corresponding annual average (Column L) for the years 2012 through 2020. The seasonality for years 2021 through 2050 in the analysis below uses the 2021 seasonality.

	Mankato Yearly Avg ($/mmBtu)	Ventura Yearly Avg ($/mmBtu)
	[TRADE SECRET DATA BEGINS….	
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050		
	ADE SECRET DATA ENDS]	

	Avg
1	Jan
2	Feb
3	Mar
4	Apr
5	May
6	Jun
7	Jul
8	Aug
9	Sep
10	Oct
11	Nov
12	Dec

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2050
[TRADE SECRET DATA BEGINS….									
… TRADE SECRET DATA ENDS]									

Mankato Total Gas Commodity Cost = Ventura Hub Price + (Fuel Percentage * Ventura Hub Price) + Firm Rate

Mankato

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
	[TRADE SECRET DATA BEGINS….				
Jan-12					
Feb-12					
Mar-12					
Apr-12					
May-12					
Jun-12					
Jul-12					
Aug-12					
Sep-12					
Oct-12					
Nov-12					
Dec-12					
Jan-13					
Feb-13					
Mar-13					
Apr-13					
May-13					
Jun-13					
Jul-13					
Aug-13					
Sep-13					
Oct-13					
Nov-13					
Dec-13					
Jan-14					

PUBLIC DOCUMENT: TRADE SECRET DATA EXCISED

Northern States Power Company
Mankato

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Feb-14					
Mar-14					
Apr-14					
May-14					
Jun-14					
Jul-14					
Aug-14					
Sep-14					
Oct-14					
Nov-14					
Dec-14					
Jan-15					
Feb-15					
Mar-15					
Apr-15					
May-15					
Jun-15					
Jul-15					
Aug-15					
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Oct-15					
Nov-15					
Dec-15					
Jan-16					
Feb-16					
Mar-16					
Apr-16					
May-16					
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Jul-20					
Aug-20					
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May-21					
Jun-21					
Jul-21					
Aug-21					
Sep-21					
Oct-21					
Nov-21					
Dec-21					

PUBLIC DOCUMENT: TRADE SECRET DATA EXCISED

Northern States Power Company

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Jan-22					
Feb-22					
Mar-22					
Apr-22					
May-22					
Jun-22					
Jul-22					
Aug-22					
Sep-22					
Oct-22					
Nov-22					
Dec-22					
Jan-23					
Feb-23					
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Apr-23					
May-23					
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Jun-29					
Jul-29					
Aug-29					
Sep-29					
Oct-29					
Nov-29					

PUBLIC DOCUMENT: TRADE SECRET DATA EXCISED

Northern States Power Company
Mankato

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Dec-29					
Jan-30					
Feb-30					
Mar-30					
Apr-30					
May-30					
Jun-30					
Jul-30					
Aug-30					
Sep-30					
Oct-30					
Nov-30					
Dec-30					
Jan-31					
Feb-31					
Mar-31					
Apr-31					
May-31					
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Jun-36					
Jul-36					
Aug-36					
Sep-36					
Oct-36					
Nov-36					
Dec-36					
Jan-37					
Feb-37					
Mar-37					
Apr-37					
May-37					
Jun-37					
Jul-37					
Aug-37					
Sep-37					
Oct-37					

PUBLIC DOCUMENT: TRADE SECRET DATA EXCISED

Northern States Power Company
Mankato

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Nov-37					
Dec-37					
Jan-38					
Feb-38					
Mar-38					
Apr-38					
May-38					
Jun-38					
Jul-38					
Aug-38					
Sep-38					
Oct-38					
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May-41					
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Nov-44					
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Jan-45					
Feb-45					
Mar-45					
Apr-45					
May-45					
Jun-45					
Jul-45					
Aug-45					
Sep-45					

Northern States Power Company
Mankato

PUBLIC DOCUMENT: TRADE SECRET DATA EXCISED

	Ventura Hub ($/mmBtu)	Fuel Percentage - Northern Natural Gas (%)	Firm Rate - Northern Natural Gas ($/mmBtu)	Mankato Total Gas Commodity Cost ($/mmBtu)	Strategist Mankato Total Gas Commodity Cost ($/mmBtu)
Oct-45					
Nov-45					
Dec-45					
Jan-46					
Feb-46					
Mar-46					
Apr-46					
May-46					
Jun-46					
Jul-46					
Aug-46					
Sep-46					
Oct-46					
Nov-46					
Dec-46					
Jan-47					
Feb-47					
Mar-47					
Apr-47					
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Oct-50					
Nov-50					
Dec-50					

TRADE SECRET ENDS]

Northern States Power Company

Docket No. E002/CN-12-1240
Information Request DOC-042 Supplement
Attachment B, Page 1 of 1

Gas Supply Costs for MN IPP Bids

PUBLIC DOCUMENT: TRADE SECRET DATA EXCISED

Firm Option

Plant	Connecting Pipeline	Capacity (MW)	Heat Rate (MMBtu/MWh)	Demand Volume (Dth/hour)	Demand Volume (Dth/day)	Minimum Delivery Pressure (psig)	Market Price	Annual Demand ($/year)	Total Variable Costs ($/Dth) (1)	Fuel 1/	Comments
								TRADE SECRET BEGINS:			[TRADE SECRET BEGINS:
Calpine Mankato	Firm NNG	345	7.25	2,501	40,020	550	Ventura		$0.0377	.27 % 1.37%	
Invenergy Hampton	Firm NNG	357	10.9	3,891	62,261	550	Ventura		$0.0377	.27 & 1.37%	
	GMT								$0.0100		
	Total								$0.0477		
Invenergy Cannon Falls	Firm NNG	179	10.9	1,951	31,218	550	Ventura		$0.0377	.27 & 1.37%	
	GMT								$0.0100		
	Total								$0.0477		
								TRADE SECRET ENDS]			TRADE SECRET ENDS]

Interruptible Option

								[TRADE SECRET BEGINS:			
Invenergy Hampton	Int NNG	357	10.9	3,891	62,261	550	Ventura		0.2675 & 0.6275	.27 & 1.37%	Plant subject to interruption (2)
	GMT								$0.0100		
	Total								$0.0100		
Invenergy Cannon Falls	Int NNG	179	10.9	1,951	31,218	550	Ventura		0.2675 & 0.6275	.27 & 1.37%	Plant subject to interruption (2)
	GMT								$0.0100		
	Total								$0.0100		
								TRADE SECRET ENDS]			

(1) Rates are lower during the summer months of April - October and higher in the winter months of November - March.

(2) Using interruptible services only, plant may be without fuel occasionally in the summer due to pipeline maintenance and emergency operations. In the winter, service will be interrupted on many days due to firm customer demand.