STATE OF MINNESOTA
BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY TO INITIATE A COMPETITIVE RESOURCE ACQUISITION PROCESS

MPUC DOCKET NO. E002/CN-12-1240
OAH DOCKET NO. 8-2500-30760

XCEL ENERGY'S POST-HEARING REPLY BRIEF

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the initial briefs of the other parties. Upon review of the briefs, as well as the public comments received into the record, Xcel Energy confirms the positions and recommendations in our initial brief.

Overall, the record establishes the potential need for incremental natural gas-fired capacity in the 2017-2019 timeframe. While Parties disagree on the amount and basis of the need, the record establishes sufficient need (up to 500 MW per the Department's analysis and about 300 MW per Xcel Energy's update) to pursue new natural gas capacity. Black Dog Unit 6 – combined with either Calpine's Mankato or Invenergy's Cannon Falls expansion projects - are the best alternatives to meet the potential need. Each of these three plants constitutes a brownfield expansion of existing power plant resources that result in low-cost resources for our customers.

The choice between Calpine and Invenergy is very close; thus, the best way to choose between them is through simultaneous PPA negotiations, allowing the

Commission to assess the overall best resource portfolio for our customers. Finally, the Commission should accept our proposed MERP-style cost recovery proposal for Black Dog Unit 6 as the best way to keep costs low and provide customer benefits.

II. SUMMARY OF REPLY

Upon reviewing the parties' briefs and public comments, three principal issues stand out for discussion in reply: (i) what is the need to be met and how should that need be calculated; (ii) which alternatives should be selected to meet the need; and (iii) what is the process the Commission should employ for resource selection and deployment to meet that need. Our Reply is structured around these three issues, rather than replying individually to each of the parties.[1]

First, there is a broad spectrum of views on the Company's need in 2017-2019. The Department concludes the Company's need is up to 500 MW by 2019 as described by the Commission in its March 5, 2013 Resource Plan Order in Docket E002/RP-10-825. By contrast, XLI and Ecos Energy question whether there is any need in the 2017-2019 timeframe to justify the selection of any resources in this proceeding at all. GRE asserts that uncertainty around the need level should lead the Commission to select its capacity credit proposal over new construction. And Geronimo and its supporters asks that its project be chosen irrespective of the level of need.

The record, however, shows the potential need for new incremental natural gas-fired generation. The most recent data in the record supports finding over 300 MW of potential need by 2019, assuming the new MISO capacity reserve

[1] In addition to the briefs filed by the parties, public comments were filed by the Xcel Large Industrials (XLI), Ecos Energy (Ecos), Minnesota Solar Energy Industry Association (MnSEIA), and the City of Minneapolis (City). While the public comments are generally not based upon the evidentiary record developed in this case, they provide additional context for the Commission's consideration. Our brief focuses on the issues raised by the parties, while also responding to points raised by the commenters that are germane to those issues.

methodology is not used to adjust the level of need. Thus, the record supports our recommendation to pursue a combination of brownfield natural gas resources at this time. However, parties recognize uncertainty surrounding the need level. Continuing soft forecasts and evolving MISO capacity reserve requirements could reduce or eliminate the need. In our judgment, it is prudent to pursue new generation to be prepared to meet the peak demand and reserve requirements presented in this Docket.

At the same time, however, resource need uncertainty dictates that it is in our customers' interest that we have the flexibility to delay or even cancel projects in response to evolving circumstances. As a result, the Company continues to recommend that we provide need updates in the Fall of 2014 and 2015 with the potential that we change course if the need picture changes significantly. This strikes a prudent balance between the need to begin deploying new resources to meet the potential need while maintaining options if that need level degrades. This ensures that resources are timely selected for implementation, while providing the Commission the flexibility to tailor that implementation so that only those resources necessary to meet the need that materializes in the 2017-2019 time period will be built.

Second, there is a diversity of views regarding how the Commission should consider project performance characteristics in addition to cost when deciding among alternatives. Invenergy and Calpine focus on real and imagined differences between Invenergy's combustion turbine (CT) and Calpine's combined cycle (CC) proposals, each claiming those differences warrant selection of its project to the exclusion of the other. They each argue that the analysis should be skewed in its favor to make its project look better by comparison. Geronimo and its supporters instead focus on the environmental attributes of solar generation and assert that those attributes were inadequately included in the Department's and the Company's analyses.

The Company respectfully disagrees with these other parties. The Strategist analyses conducted independently by the Company and the Department confirm that Black Dog Unit 6 is an appropriate choice and that the choice between Calpine and Invenergy is very close. The Strategist modeling takes into account the performance characteristics of CT and CC technology that are germane to the determination of the relative value of each technology to our customers under the present circumstances. Strategist provides an 'apples-to-apples' comparison of the relative costs and benefits of the natural gas proposals and provides a sound basis for choosing among the alternatives.

While Xcel Energy remains fully committed to developing cost-effective solar resources and meeting our commitments to renewable energy, the public interest favors choosing natural gas alternatives over solar in this instance. The record establishes that, in addition to economics, choosing natural gas resources provides reliable and dispatchable resources. Further, Xcel Energy is obligated to consider the least-cost solar resources available to meet the new solar mandate. It is not in the public interest to pick solar in this proceeding where there was no solar competition and no way to effectively probe the marketplace to determine the most competitive pricing available among solar proposals. While Xcel Energy fully supports the State's solar energy goals and intends to comply with the solar mandate, it is premature to select solar in this proceeding.

Finally, there is substantial disagreement over how the resource selection and the implementation process should proceed. Calpine, Invenergy, and Geronimo each believe the Commission should select their respective project before the PPA negotiation phase, and that the PPA negotiation phase should not be competitive. The Company and Department, however, agree that the best way to achieve the final portfolio is to proceed with simultaneous negotiations with Calpine and Invenergy.

The Company urges that the Commission's final selection include Black Dog Unit 6 plus either Calpine or Invenergy, depending on which proposal offers our customers the best overall value, based on the outcome of PPA negotiations.[2]

Finally, our MERP-style cost recovery proposal for Black Dog Unit 6 provides the optimal balance of cost discipline and value to our customers. As a rate regulated utility, our proposal to add Black Dog Unit 6 to our system does not raise the same types of construction, operation, maintenance, and financial accounting and security issues that need to be addressed in the PPA negotiations for the Mankato and Cannon Falls projects. Our proposal creates an incentive for us to hold the line on costs and ensures that our customers share in that benefit. While we do not object to the Department's alternative proposal that Black Dog Unit 6 be held to its proposed capital costs and that the Company retain the benefit of all cost savings, we do not believe such a proposal optimally strikes the same balance since it does not share savings with our customers.

The balance of this brief is organized into the following sections:

- Standard of Review Revisited
- Need Issues
- Alternatives Issues
- Resource Selection Process Issues
- Conclusion

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[2] The Company also recommends the Commission consider holding Red River Valley Unit 1 in reserve in the event neither the Cannon Falls nor Mankato PPA is acceptable to the Commission upon completion of the negotiation phase. This greenfield unit is an attractive option to ensure that we can successfully fill the need in this case, is close in cost to the brownfield proposals, and at the same time adds geographic diversity and long-term value to our system.

III. STANDARD OF REVIEW REVISITED

All parties agree that this resource acquisition process is being conducted under the Commission's "track two" resource acquisition requirements and is intended to be a certificate of need "like" process. There is some disagreement, however, as to how the specifics of the certificate of need statute and rules should be implemented in light of the fact that this proceeding will not result in the issuance of a formal certificate of need.[3] The Company agrees with the Department that a formal certificate of need is not required. Nevertheless, the standards and requirements of the certificate of need statute and rules provide important guidance for the analysis and selection of resources in this proceeding.

The Commission's order establishing the competitive bidding process used in this proceeding emphasizes the importance of the certificate of need requirements in analyzing the proposals in this "track two" selection process. The "certificate of need filing requirements and decision criteria are clear, comprehensive, directly relevant . . . , and easily transferable to the resource procurement process."[4] Thus, while Minn. Stat. § 216B.243 and the other certificate of need statutes may not technically govern this proceeding, they provide an important foundation for the Commission's decision.

In any case, no one disputes that the four factors found in Minnesota Rule 7849.0120 are important to the Commission's decision. These factors are:
A) probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant; B) a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a

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[3] *See* Environmental Intervenors' Initial Brief at 2-3 and Exhibit A.

[4] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, Docket No. E002/RP-04-1752, ORDER ESTABLISHING RESOURCE ACQUISITION PROCESS, ESTABLISHING BIDDING PROCESS UNDER MINN. STAT. § 216B.2422, SUBD. 5, AND REQUIRING COMPLIANCE FILING at 6-7 (May 31, 2006) (emphasis added) ("Track 2 Resource Acquisition Order").

preponderance of the evidence; C) a preponderance of the evidence shows the proposed facility will provide benefits compatible with protecting the natural and socioeconomic environments; and D) the record does not demonstrate the design, construction, or operation of the proposed facility will not comply with relevant state, federal, and local government policies and regulations. Xcel Energy believes that the best guide in the decision-making process is to apply the four-factor test under the Commission's certificate of need rules to the record developed in this proceeding.

IV. NEED ISSUES

All the parties except Calpine and Invenergy addressed need in their initial briefs, as did XLI and Ecos in their comments. This issue is relevant to the first of the four factors in Minnesota Rule 78249.0120: the probable result of denial would be an adverse effect upon the future adequacy of the Company's energy supply.

A. Department Need Analysis

The record contains a series of data points supporting a system capacity need in 2019 of as much as 500 MW to somewhere in the range of 300 MW. The record suggests the need level could be lower as a result of continued soft demand and application of evolving MISO reserve margin requirements. The Department concludes that the Commission's finding in the Company's Resource Plan proceeding is dispositive of the need question and that the Company needs up to 500 MW by 2019.[5] Whether or not the Commission's Resource Plan finding is dispositive, data points in the record suggest a potential need in the 300 MW range in 2019 based upon the latest forecast updates (assuming no adjustment due to evolving MISO capacity

[5] Department Initial Brief at 10-12.

reserve margin requirements).[6] Based on their independent analyses, the Company and Department agree that construction of natural gas-fired capacity resources is required to satisfy the actual need.

Geronimo, on the other hand, notes that the record evidence indicates our need may be anywhere from 26 MW to 443 MW by 2019.[7] In light of this, Geronimo argues that the Commission should in essence determine the Company's need by starting at the low end of the range and selecting Geronimo's proposal first.[8] "If the Commission determines it is prudent to add additional generation beyond the 71 MW of accredited capacity provided [by] the Solar Proposal, <u>only then</u> should it consider which of the remaining alternatives should also be selected."[9]

XLI asserts that the Commission should make no resource selection in this proceeding because of the uncertainty surrounding our need, including the impact of adding solar capacity to meet the new solar mandate. Ecos' public comment also suggests that the addition of solar to our system in the coming years will offset the need for additional capacity. These arguments misstate the record. In developing our September 2013 forecast update, the Company included the impact of adding solar capacity to the system in the 2017-2019 timeframe.[10] While the addition of new solar

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[6] Xcel Energy Initial Brief at 13-14.

[7] Geronimo Initial Brief at 12.

[8] Geronimo Initial Brief at 15.

[9] *Id.* (emphasis added). The Environmental Intervenors also support the selection of Geronimo's resource proposal, as do MnSEIA and the City of Minneapolis. As noted in the City's comments, the Company has signaled our support of the City's Climate Action Plan, which has specific citywide Green House Gas (GHG) emissions reduction goals for 2015 and 2025. We also support Minnesota's environmental policy objectives, and continue to participate in the Clean Air Minnesota dialogue, which is evaluating ways to continue to proactively reduce emissions in the state. As further noted in the City's comments, there has been a marked reduction in GHG gas production due to increased use of natural gas and wind power. Adopting the gas bids submitted in this matter would further that trend. To the extent to which the City has raised other points based on the evidentiary record, these are similar to those raised by Geronimo and are addressed throughout this brief.

[10] Ex. 46 (Wishart Direct) at 7, Table 1; *see also* Xcel Energy Initial Brief at 10.

resources does indeed reduce the potential for a capacity shortfall, that reduction is taken into account in the September 2013 update.

The varying views of the level of need supported by the record in this case highlight the fact that there is considerable uncertainty about what the exact level of our need will be in the 2017-2019 timeframe. Forecasts continue to be soft, raising the risk that some new demand may not materialize. In addition, as the Department describes in detail, application of the evolving MISO capacity reserve requirements could have a significant impact on the need.[11]

As the provider of last resort, Xcel Energy recognizes our obligation to have sufficient generating resources available to meet our customers' demands under all reasonable circumstances. Accordingly, based on this record, we believe the Company should be prepared to add the new generation required to meet the need that emerges in 2017-2019 in a timely manner.

Our recommendation continues to be that the Commission recognize the uncertainty we face and provide for flexibility to adapt to changing circumstances. Because of the uncertainty identified, we continue to recommend that the Commission review the Company's need and the selected resources in the Fall of 2014 and 2015 to determine whether changed circumstances warrant delaying or cancelling the implementation of one or both of the resources selected in this proceeding.[12] As described later in this Reply, our proposal to conduct simultaneous PPA negotiations with both Calpine and Invenergy includes exploring options that

[11] Department Initial Brief at 32-36.

[12] GRE proposes that its proposal be included in the PPA negotiations with Calpine and Invenergy to explore how it can be used to address changed circumstances that may warrant the delay of these projects. GRE Initial Brief at 6-7. This misses the point. Circumstances warranting delay of the selected natural gas units would not require GRE's paper capacity credit instead. Moreover, GRE's proposal does not represent a least cost alternative. The Company's modeling showed that the addition of GRE's capacity credit to a portfolio allowed one of the two natural gas units in the portfolio to be delayed by a year, but that the cost of the credit for that period exceeded the cost savings realized from the delay. Ex. 46 (Wishart Direct) at 33.

would give the Commission the flexibility to delay or even cancel the projects if the need does not materialize. We expect that contractual delay or termination rights will come at some cost in the form of price increases for delay and termination payments to reimburse the vendor for sunk costs, which may affect which project to select. Nonetheless, we believe it will be appropriate to provide that flexibility to the Commission for its consideration under these circumstances.

B. XLI's Need Analysis

XLI points to continued soft demand forecasts and the reduction in need in the Company's September 2013 Update and under MISO's non-coincident peak reserve margin requirements methodology as reasons to question the presence of need in this case. XLI agrees with the Company that the September 2013 Update provides another data point to consider in assessing need, as is the Company's sales forecast in its recently filed rate case, which shows continued soft demand consistent with the September 2013 Update.[13] And XLI further agrees with the Company that the continuing changes to MISO's calculations add a layer of uncertainty as to the adequacy of the Company's resources.[14]

Xcel Energy appreciates XLI's analysis of this question and recognizes that the ultimate need level in 2017-2019 is uncertain and could change. The appropriate remedy for that uncertainty, however, is not further record development at this time. Rather, because of the timelines involved in building power plants, Xcel Energy believes it is prudent to select assets for deployment to meet the potential need while maintaining flexibility to delay or cancel deployment if subsequent events warrant. As the provider of last resort, it would not be in our customers' best interest for the

[13] XLI Comments at 8-9.

[14] XLI Comments at 9-11.

Company to be short, which could happen if we do not proceed to deploy new capacity and the potential need identified in this Docket materializes.

XLI goes further, however, arguing that because the Company "may" not have adequately accounted for the rate at which solar capacity may be added to the Company's system to meet the Solar Energy Standard (SES) set forth in Minn. Stat. § 216B.1691, subd. 2f, there is now uncertainty as to whether the Company can be said to have any capacity need at all in the 2017-2019 period.[15] XLI is mistaken, however. As Company witness Steve Wishart explained in his direct testimony, our September 2013 Update assumed that the Company will obtain all the solar energy it needs during the 2017-2019 time period to meet the approximately 290 MW of solar generation that will be needed by the end of 2020.[16] Likewise, the Company's Strategist modeling of the cost impacts of the resources proposed in this proceeding included the solar energy required to meet the mandate.[17] Fulfillment of the solar mandate therefore does not raise the specter that the Company will have no capacity need in the 2017-2019 timeframe.

Further, as described in more detail below, the Company does not support stopping the acquisition process in this proceeding based on evolving MISO reserve margin requirements. That evolving process introduces too much uncertainty at this time, and should be further developed and reviewed over the next year rather than relied upon in this proceeding.

[15] XLI Comments at 11-12. Ecos Energy also asserts that the Company's capacity need will be extinguished upon the Company acquiring all the solar energy necessary to fulfill its obligations under Minnesota's new Solar Energy Standard. Based on this, Ecos argues that whatever need the Company will have in 2017-2019 should not be determined in this Commission-ordered competitive acquisition process open to all resources, but rather only through a later RFP process limited to solar energy resources only. Ecos Energy Comments at 1-2.

[16] Ex. 46 (Wishart Direct) at 7-8.

[17] Ex. 46 (Wishart Direct) at 21-22.

C. Environmental Intervenors' Need Analysis

The Environmental Intervenors claim that the 128 MW capacity need based MISO's expected 2014 calculation of reserve margin requirements should be substituted for the 500 MW need identified by the Commission. Its only support for this claim is that no one has provided persuasive evidence that this should not be done.[18]

We respectfully disagree with the Environmental Intervenors' position that the Commission base its need determination solely on evolving MISO calculations of reserve margin requirements. Based on the Company's September 2013 Update, 2012 reserve margin methodology results in a capacity need of 307 MW in 2019, while its 2013 methodology results in a need of 26 MW in that year, and its anticipated 2014 methodology results in a 128 MW need.[19] This year-to-year instability is not conducive to resource planning, and MISO has acknowledged that it intends to address the issue.[20]

The Department's review of this issue is instructive. Department witness Dr. Rakow notes that there is uncertainty regarding how to determine the diversity factor that is used under MISO's new non-coincident peak methodology for determining reserve margins. He found that the Company provided information in response to discovery showing that there are a variety of diversity factors that would be reasonable to use.[21] Dr. Rakow also pointed out that the level of reduced demand that can be achieved through the Company's demand side management programs at the time of the Company system peak may not be as great at the time of the MISO

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[18] Environmental Intervenors Initial Brief at 11.

[19] Ex. 46 (Wishart Direct) at 10, Table 4.

[20] Ex. 46 (Wishart Direct) at 10.

[21] Ex. 83 (Rakow Direct) at 24.

system peak, which adds further uncertainty.[22] He therefore concluded that in this proceeding the reserve margin requirements associated with both the old coincident peak and the new non-coincident peak methodologies need to be considered to determine the reasonable range of the Company's capacity needs.[23]

As described in the Company's testimony, we are concerned that relying on the 2013 MISO reserve margin requirements would expose our customers to too much risk.[24] Using those evolving rules to set the need in this case presents the risk of a generation shortfall and over-reliance on the market in a period of concern about fossil fuel retirements. We believe it is more prudent to pursue generation based on what may end up being a more conservative resource assessment with flexibility to delay or cancel.

V. ALTERNATIVES ANALYSIS

All parties provided discussion of the alternatives placed in the record to meet the identified need and provided their recommendations for how best to meet that need. This is relevant to the second of the four factors in Minnesota Rule 7849.0120: a more reasonable and prudent alternative to the proposed resource has not been demonstrated by a preponderance of the evidence. Each of these positions are described below.

[22] Ex. 83 (Rakow Direct) at 24-25.

[23] Ex. 83 (Rakow Direct) at 25. The Department also notes that MISO's non-coincident peak methodology has not been brought to the Commission so there has been no determination made yet whether this significant change in determining reserve margins is reasonable for planning purposes for regulated utilities in Minnesota. Department Initial Brief at 32-33.

[24] Ex. 46 (Wishart Direct) at 10-11; Ex. 49 (Alders Direct) at 7.

A. Department's Position on Alternatives

The Department conducted an independent Strategist analysis of the resource proposals in this proceeding that included several rounds of simulations and multiple input sensitivity tests. Despite using somewhat different assumptions, the Department's analysis reaches essentially the same results as the Company's Strategist analysis.

After the first two rounds of analysis, Dr. Rakow recommended Calpine's Mankato expansion in 2017 combined with our Black Dog Unit 6 in 2019 as 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."[25] He noted that if the Commission is concerned about "the size of the package," the second ranked package under base case conditions was Calpine's proposal alone.[26] But he acknowledged that the decision to model Black Dog Unit 6 for only 20 years with an end effects adjustment rather than modeling it for its full service life of 35 years "likely does not account for the full value" of the unit.[27] Dr. Rakow concluded 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.[28]

Dr. Rakow conducted a third round of Strategist analysis that investigated the impact of deferring the in-service date of Invenergy's Cannon Falls expansion, and running the new unit with an interruptible gas supply.[29] Based on these changes, the PVSC results for the Mankato and Cannon Falls projects are much closer, and the

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[25] Ex. 83 (Rakow Direct) at 40.

[26] *Id.*

[27] Ex. 83 (Rakow Direct) at 28.

[28] Ex. 83 (Rakow Direct) at 40.

[29] Ex. 86 (Rakow Rebuttal) at 10-12.

Department agrees that Black Dog Unit 6 should be included and that both Cannon Falls and Mankato should proceed to the PPA negotiation phase.[30] The Department also agrees with the Company that maintaining competition through the negotiation phase is important to ensure that the Calpine and Invenergy provide the best available deal for our customers.[31]

Of course, if Calpine and Invenergy provide PPA terms that are unacceptable to the Commission, the Company's Red River Valley Unit 1 is another appropriate choice. Based on the specific record developed in this case, Xcel Energy recognizes that the Calpine Mankato and Invenergy Cannon Falls brownfield expansion proposals (as well as Black Dog Unit 6) are more cost effective than the Company's Red River Valley greenfield proposal. As a result, at this time, the Company views the Red River Valley project as a back-up in the event we are unable to come to appropriate terms with Calpine and Invenergy. That said, the Company remains committed to developing generation in the Northwestern part of our system. Geographic diversity of generation is an important consideration and we intend to continue working toward developing strategic sites in the Northwestern part of our system for future generation. The Red River Valley site near Hankinson, ND (or another location in the Fargo/Grand Forks area), would provide important geographic diversity to our supply portfolio and would place generation near our load centers along the Red River Valley. While, in this instance, the record did not support our Red River Valley greenfield site (due mainly to the economies involved in brownfield development), we anticipate that, as the need for natural gas capacity arises over the next 20 years, our procurement efforts will focus on geographic diversity as an important factor.

[30] Department's Initial Brief at 62.

[31] Ex. 86 (Rakow Rebuttal) at 15.

Upon completion of the PPA negotiations, the Department recommends that the Commission select the two projects with the terms most favorable to our customers.[32] Absent differences between the Cannon Falls and Mankato PPAs, the Department supports the combination of Black Dog Unit 6 with Mankato.[33]

The Company generally agrees with the Department's analysis and conclusions. In particular, we agree that Black Dog Unit 6 is one of the alternatives that should be selected. We further agree that the Calpine Mankato and Invenergy Cannon Falls proposals are economically very close and that a competitive PPA negotiation process is the best way to assess which of those projects provides the best value to our customers.

The Company respectfully disagrees with the Department, however, that the competitive PPA negotiations should delay the Commission's selection of Black Dog Unit 6. To the contrary, due to the long-term benefits of Black Dog Unit 6 – a 35-year life versus 20-year contract term for the PPAs – the Company's project demonstrates clear economic value and should be included. The Department's analysis only evaluated the first 20 years of Black Dog Unit 6, ending its Strategist simulations in 2036.[34] This analytic approach understates the unit's greatest savings for customers, and as such led to incomplete results. The Commission should, therefore, select Black Dog Unit 6 as one of the alternatives and order simultaneous PPA negotiations with Calpine and Invenergy. The Commission can then assess the outcome of those negotiations and pick the PPA alternative that optimizes value to our customers.

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[32] Department's Initial Brief at 62.

[33] Department's Initial Brief at 63.

[34] Ex. 83 (Rakow Direct) at 29.

B. **Calpine's Position on Alternatives**

Since the net present value of the Mankato and Cannon Falls expansions are essentially the same, Calpine focuses its arguments on the differing performance characteristics of CC and CT natural gas generation. Some of those differences are real, some are imagined, and nearly all of them are offset in one way or another. While Calpine claims its identified differences warrant selection over Invenergy, the net effect of Calpine's arguments, when read in conjunction with Invenergy's contrary arguments (as described below), highlight just how close the decision is and why it is important to negotiate PPAs with both of them as part of the selection process.

Contrary to Calpine's arguments, the Strategist modeling by both the Company and the Department captured the material performance differences between CT and CC technology and their impact on system costs. In the end, Xcel Energy continues to support selecting the Calpine Mankato expansion as appropriate to meet a portion of the potential need, and to proceed to PPA negotiations to determine the overall value of its proposal compared to the Invenergy proposal.

Calpine claims that the failure of the Company and the Department to add certain factors to their analyses resulted in the cost value of its Mankato project being understated. In addition, Calpine asserts that its Mankato project is superior to the CT projects based on certain non-price qualitative factors. These are discussed below.

1. Levelized Cost of Energy (LCOE)

Calpine bases its analysis on the LCOE methodology for assessing the costs of various proposals. That methodology is not supported on this record and is demonstrably inferior to the Strategist analysis provided by the Department and the Company.

As the name implies, a LCOE analysis only evaluates the cost of a generation resource, completely ignoring the different benefits that a resource may provide. As a result, LCOE is only appropriately used when comparing very similar resources where price is the only distinguishing factor between the resources. In this proceeding, however, there is a wide variety of resources: peaking, intermediate, natural gas, solar, and short-term "paper" capacity resources. In this situation, a proper analysis must examine both the costs of the proposed resources and their widely varying benefits, which is what the Strategist simulation model does.[35]

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:

> . . . <u>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</u>. 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 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

[35] Ex. 48 ('Wishart Rebuttal) at 15-16.

of the power system with and without any project under consideration.[36]

The Strategist simulation performed by the Company and the Department do precisely this. The Strategist model contains all of the project cost information used to calculate LCOE values, but it also performs dispatch simulations to estimate each project's avoided costs.[37]

The LCOE approach focuses only on the various costs of a proposal, failing to provide a complete cost-benefit analysis. We therefore recommend that Calpine's LCOE analysis not be relied upon at all in the Commission's selection of resources in this proceeding. Calpine will not be significantly harmed by this, however, since both the Company's and the Department's analyses support the selection of its Mankato project.

2. Selective Catalytic Reduction (SCR)

Calpine recommends that the costs of selective catalytic reduction (SCR) be added to the base costs of Invenergy's and the Company's peaking proposals.[38] However, the record establishes that both Black Dog Unit 6 and Cannon Falls are anticipated to meet all emission permitting requirements without SCR technology.[39] Calpine is correct that the emission of NOx and other effluents are higher with peaking units in comparison to intermediate combined cycle plants. However, the Strategist simulations conducted by the Company and the Department included detailed emission inputs for every generation unit on the Company system, and the

[36] Ex. 48 (Wishart Rebuttal) at 16-17 (emphasis added) (citing: http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf, which was last viewed on December 1, 2013).

[37] Ex. 46 (Wishart Direct) at 21, 23.

[38] Ex. 52 (Hibbard Direct) at 29-30 and n.35.

[39] Ex. 43 (Ford Rebuttal) at 3-4; Invenergy Initial Brief at 53-54.

difference in total system emissions is tracked by the model.[40] The Strategist model also included the Commission established cost for environmental externalities and forecasted CO2 compliance costs.[41] The result is that the Strategist simulations quantified the value of lower emissions from the Calpine proposal based on Commission approved values.

3. Fuel Supply

Calpine also claims that its Mankato project is being improperly undervalued as a result of the Invenergy Cannon Falls proposal being modeled on interruptible gas. Specifically, Calpine reasons that since Cannon Falls is <u>not</u> competitive when modeled with firm gas as Mankato and Black Dog Unit 6 were, Cannon Falls should be eliminated from further consideration.[42]

Calpine justifies this position on the grounds that all thermal projects should be analyzed the same way to ensure a level playing field. This position is based on a false premise as it ignores important differences between CC and CT technology and how these two technologies are used in power generation. The record is clear that CTs generally operate less than 5% of the time, and typically only in the summer when there is a surplus of natural gas supply.[43] Interruptible gas service may be appropriate for CTs under these circumstances. By contrast, Calpine recognizes that CC units can be expected to operate with capacity factors of 20 or more, and may be called on at

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[40] Ex. 46 (Wishart Direct) at 21.

[41] Ex. 46 (Wishart Direct) at 21-22.

[42] Calpine Initial Brief at 18.

[43] Ex. 46 (Wishart Direct) at 13, 14, 15; Hrg. Tr. Vol. I at 117-19.

any time to supply intermediate priced energy.[44] As a result, it is important that a CC have firm fuel service to support that higher expected operations pattern.[45]

With an interruptible contract for natural gas supply, the Invenergy project would still have access to the necessary fuel supply in most hours of the year. Only during extremely cold weather, when demand for natural gas is at its highest, would the fuel supply be curtailed.[46] The Company specifically modeled the impact of fuel curtailment at Cannon Falls for the entire winter, and found that the PVSC impact would be negligible.[47] The Company also evaluated what the impact of having Cannon Falls on interruptible gas might be on the Company's system, and found that because the system currently has excess capacity in the winter months, there would be essentially no impact to system reliability.[48]

4. *Qualitative Factors*

Calpine identifies four qualitative factors that it says establish the superiority of Mankato as an addition to the Company's system over Black Dog Unit 6 and Cannon Falls. The evidentiary record is to the contrary.

Calpine first claims that its CC project must be recognized as environmentally superior to the CT projects because it generates less emissions per MWh than they do.[49] However as previously mentioned, Strategist calculates the additional costs associated with emissions based on Commission approved values. Schedule 4 of the

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[44] Ex. 46 (Wishart Direct) at 17.

[45] Ex. 48 (Wishart Rebuttal) at 19.

[46] Ex. 48 (Wishart Rebuttal), Schedule 1 at 5.

[47] Ex. 48 (Wishart Rebuttal) at 20-21.

[48] Ex. 48 (Wishart Rebuttal) at 23. The availability and desirability of back-up fuel for the Cannon Falls expansion project is a subject that can be explored during the PPA negotiations. Ex. 46 (Wishart Direct) at 50.

[49] Calpine Initial Brief at 20-24.

public version of Mr. Wishart's direct testimony (Exhibit 86) includes tables that list the net emission costs differences between various alternatives. Because the emission profiles of the natural gas proposals are not all that different from each other, the Strategist results show that emission costs play a relatively small role in the economic evaluation of these resource proposals

Next Calpine claims it should be given greater value because it serves as a hedge against future resource retirements in the region.[50] As the Department notes, the goal in this proceeding is to determine how the cost of operating the Xcel Energy system will be affected by the addition of the resources proposed in this proceeding, not how they impact MISO's ability to better manage its system,[51] such as hedging against capacity shortages due to resource retirement. The last two non-renewable resource addition to the Company's system were also intermediate CC units: High Bridge and Riverside. Currently these two units are under-utilized and thus available to hedge against any unforeseen retirements.[52] The addition of the Calpine's CC unit would only provide marginal benefits associated with retirement hedging.

Calpine also claims that the Mankato expansion has greater ability to support the integration of renewable resources, asserting that CT capacity is a more expensive and higher-emitting way to meet any net load variability that could otherwise be met by CC capacity.[53] While CC technology is appropriate and valuable in many circumstances, it is not a panacea that is best for all circumstances. Calpine witness Mr. Hibbard acknowledged that CCs cannot provide integration of renewable resources if the CC is not already on-line, and that it takes several hours to bring them

[50] Calpine Initial Brief at 24-25.

[51] Ex. 86 (Rakow Rebuttal) at 17-18.

[52] Ex. 1 (Company's Proposal) at 1-14 to 1-15.

[53] Calpine Initial Brief at 26.

on line from a cold start.[54] This is a disadvantage of CC technology compared to CT technology to the extent that resources are needed to "follow" the variability of wind and solar resources as the weather changes. Thus the record shows that both CT and CC units can be valuable resources for integrating renewables.

The final qualitative factor Calpine relies upon is its "foresight" in planning to add a second CC unit at its existing Mankato plant site. Calpine touts this foresight as allowing it to price its proposal aggressively and reduce the proposal's impacts on the environment and community in which it will be located.[55] But the same is true of course with both Black Dog Unit 6 and Cannon Falls, which are also expansion projects at brownfield sites. There does not appear to be any record evidence indicating the magnitude of the environmental and community benefits is greater for the Mankato project than for the other two.

C. Invenergy's Cannon Falls Proposal

Invenergy takes the contrary position in its brief that a CT unit (so called 'capacity resource') is preferable to a CC unit (so called 'energy resource') in meeting the Company's potential need. Similar to Calpine, Invenergy notes real and imagined differences in an effort to make its proposal seem better in comparison. Again, these arguments, when read in conjunction with Calpine's brief, reinforce the need for competitive PPA negotiations to ensure we receive optimal value for our customers.

Invenergy identifies various issues as demonstrating the superiority of its Cannon Falls proposal over Calpine's Mankato expansion project and the Company's Black Dog Unit 6. For the most part, Invenergy's arguments involve qualitative analyses that do not alter the conclusions to be drawn from the Strategist modeling that has been done in this proceeding, or are contrary to the record evidence.

[54] Hrg. Tr. Vol. I at 42-43

[55] Calpine Initial Brief at 27-29.

1. *CTs Better Fit Xcel Energy's System*

While Calpine proclaimed the benefits of CC technology in supporting the integration of intermittent resources into the Xcel Energy system, Invenergy touts the benefits of CT technology to do the same thing.[56] As previously discussed, however, both types of resources can help balance intermittent generation, and therefore this aspect of the proposal should not be used as a deciding factor in resource selection.

In further support of its claim that a CT unit would better fit the needs of the Company's system, Invenergy notes there is a lower ratio of peaking to wind capacity on the Company's system than on the system of our affiliate Public Service Company of Colorado (PSCo).[57] PSCo, however, does not belong to a Regional Transmission Organization like MISO, and so the issues PSCo must address with respect to the balance of resources within its fleet and how they are dispatched to maximize the efficiency and effectiveness of PSCo's system can be materially different than those faced by the Company.

Invenergy further asserts that its CT proposal at Cannon Falls will help address the declining load factor of the Company's system.[58] Like Calpine, Invenergy exaggerates the point in an attempt to make its project look better by comparison. The Strategist modeling included updated load forecasts that incorporated the minor decrease in load factor that is expected.[59] The modeling results show that both CT and CC technologies have the potential to add value to our system. There is no meaningful distinction based on the criterion of changing load patterns.

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[56] Invenergy Initial Brief at 18-22.

[57] Invenergy Initial Brief at 20-21.

[58] Invenergy Initial Brief at 25-27.

[59] Ex. 46 (Wishart Direct) at 21.

2. *Unnecessary Costs of Alternatives*

Invenergy qualitatively argues about the appropriate level of CT versus CC capacity on our system to support its claim that Calpine's Mankato proposal will unnecessarily increase costs for our customers.[60] This argument is also misguided. The Strategist modeling that has been conducted by the Company and the Department accounted for all the various costs and benefits of adding these proposed CT and CC resources to the Company's system, and the results demonstrate that the PVSC of Cannon Falls and Mankato are very close. While the monthly fixed payments to Calpine would indeed be higher, the Calpine project creates significant fuel cost savings through its higher efficiency.[61]

The record also does not support Invenergy's contention that the Company's Black Dog Unit 6 proposal will impose unnecessary costs on our customers.[62] Our recommendation is for the Commission to select Black Dog Unit 6, in combination with either Mankato or Cannon Falls.[63] Building a peaking facility with a 35-year or more life does not "lock" our customers into a resource acquisition to their disadvantage, as Invenergy implies.[64] Rather the record evidence shows that Black Dog Unit 6 will be lower cost than Invenergy's project during its 20-year contract period, and will then provide on-going benefits after the Invenergy contract has expired.[65] As Dr. Rakow acknowledged, years 21-35 of Black Dog Unit 6 provides real customer value that has not been fully captured by the Department's modeling.[66]

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[60] Invenergy Initial Brief at 29-33, 44-47.

[61] Ex. 46 (Wishart Direct) at 17.

[62] Calpine Initial Brief at 33-37.

[63] Ex. 46 (Wishart Direct) at 40; Ex. 49 (Alders Direct) at 8. Thus our recommendation is not to provide over 600 MW of capacity, as Invenergy claims. Invenergy Initial Brief at 34.

[64] Invenergy Initial Brief at 34.

[65] Ex. 46 (Wishart Direct), Schedule 4 at 1.

[66] Ex. 83 (Rakow Direct) at 28.

3. Inadequate Strategist Modeling

Invenergy reviews a variety of problems it sees with the Strategist modeling in this proceeding,[67] claiming that if these problems were all fixed its project would be the "clear winner."[68] But what the record evidence shows is that despite the differing assumptions between the Company's Strategist modeling and the Department's three rounds of Strategist modeling, the Cannon Falls and Mankato projects were determined to be too close in cost for either to be declared the outright winner over the other.

Further, the in-service date and expected forced outage and emission rate assumptions used in the Company's and Department's Strategist analyses were those included in Invenergy's bid information, and thus modeled in the same manner as those same assumptions were modeled for Calpine's Mankato proposal and the Company's Black Dog Unit 6 proposal.[69] Thus, Invenergy's Cannon Falls facility was modeled on a consistent basis with, and can be judged consistently against, the other natural gas proposals.

D. Geronimo Solar Energy Proposal Issues

Geronimo argues that its solar proposal is the least cost resource and is a statutorily preferred low-emission, renewable distributed generation resource.[70] As such, Geronimo argues its proposal should be selected first, regardless of the level of need established on the record.[71]

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[67] Invenergy Initial Brief at 37-42.

[68] Invenergy Initial Brief at 42.

[69] Ex. 46 (Wishart Direct) at 23; Ex. 83 (Rakow Direct) at 4.

[70] Geronimo Initial Brief at 1-2.

[71] *Id.*

1. Least Cost Resource

Geronimo's first claim is that its solar proposal has the lowest LCOE.[72] The shortcomings of LCOE analysis have been previously addressed in Section V.B.1.a. The LCOE approach only evaluates the costs of projects while ignoring the avoided cost benefits that each project will produce. Evaluating only costs, while ignoring benefits, will in most cases lead to faulty conclusions.

Geronimo next claims that its proposal would have been identified by Strategist as the least cost option if certain additional benefits of solar had been recognized: 1) transmission line losses, 2) the market value of solar renewable energy credits (S-RECs), 3) avoided transmission capacity costs; and 4) the project's higher PVSC being minor.[73] None of these claims withstand scrutiny.

Transmission Line Losses. First, the issue of transmission line losses was addressed in the Company's testimony. Although not specifically included in the Strategist model, the Company estimated that avoided line losses could account for an additional $10 million benefit for the Geronimo project. This benefit was insufficient to overcome the $34 million rate impact of the solar proposal.[74]

Value of S-RECs. Second, while Geronimo is correct that the generation from their project would be used for compliance with the Minnesota solar energy standard, there is no way at this time to substantiate the value of S-RECs in Minnesota. Both the Company and the Department have recommended a separate solar RFP that will identify the lowest cost solar available for compliance.

Under Geronimo's proposal as submitted, the PPA price covers <u>both</u> the energy produced by the project and the S-RECs associated with that energy. In other

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[72] Geronimo Initial Brief at 16-17.

[73] Geronimo Initial Brief at 19-20.

[74] Ex. 46 (Wishart Direct) at 35.

words, Xcel Energy obtains the S-RECs without further compensation to Geronimo as the value of the S-RECs is already embedded in the energy price. If Geronimo believed in their stated S-REC values, one option available to them would have been to sell only the energy from the project at a reduced price to reflect the value of the retained S-RECs, while keeping the S-RECs for themselves to then later be sold on the open market.

Further, once obtained pursuant to Geronimo's proposed PPA, the Company would use the S-RECs to fulfill its SES obligations. This means that we would retire those S-RECs in the course of complying with our State-law solar generation obligations. In short, Xcel Energy will have nothing to sell in the market to realize additional "savings." Thus, the S-RECs have no value to Xcel Energy beyond compliance with its solar energy requirements.

As explained by Company witness Steve Wishart, the generic solar units in Strategist were priced below Geronimo's units based on market information the Company had from other jurisdictions, adjusted for Minnesota.[75] As a result, if the Geronimo project was modeled to fulfill the SES, Strategist would have had to select it over cheaper priced generic units, thus <u>increasing</u> the cost of adding the Geronimo project to our system beyond what the cost of the project when modeled as it was by the Company - to <u>not</u> displace cheaper solar units.[76] Under either modeling scenario, the Company would use the S-RECs obtained from the selection of the Geronimo proposal to meet its obligations under SES and there would be none available for sale to realize further savings against the PVSC of the proposal as modeled.

Avoided Transmission. Third, Geronimo claims because the Legislature has "recognized that distributed solar energy projects have the added benefit of avoiding

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[75] Ex. 48 (Wishart Rebuttal) at 25; Hrg. Tr. Vol. I at 110.

[76] Ex. 48 (Wishart Rebuttal) at 25-26.

transmission capacity costs"[77] some value for this should be imputed to its project. However, there is no record support for actual avoided transmission arising from Geronimo's proposal. Further, the statute Geronimo cites, Minn. Stat. § 216B.164, does not contemplate that the value of the avoided transmission of a solar facility should be recognized in addition to the cost a utility pays to add the facility to its system, as Geronimo contends.

Moreover, the only transmission that likely to be avoided would be short lines used to interconnect new natural gas plants what will not be needed as a result of the SES. This cost of interconnection was included in each natural gas bid and in the Strategist modeling, and a review of the bids shows that interconnection represents a very small proportion of each project's total cost.[78] The avoided transmission capacity cost savings identified by Geronimo appear to be greatly exaggerated and therefore do not justify selection of the project.[79]

Minor PVSC Difference. Finally, Geronimo asserts that its identified $34 million rate impact is a minor cost difference in comparison to the entire costs of the Xcel Energy system.[80] However, Geronimo's proposal is not being measured against total system costs but against its cost impact relative to its size and the costs of other proposals in this proceeding. The record evidence shows that the total net present value of the payments to Geronimo if it were added to our system is $186 million, resulting in a $34 million rate impact in excess of that of Black Dog Unit 6 and

[77] Geronimo Initial Brief at 20 (citing Minn. Stat. § 216B.164, subd. 10(f)).

[78] Ex. 1 (Company's Proposal); Exs. 7 and 9 (Calpine Trade Secret Proposal and Strategist Data); Exs. 22, 27, 29, and 31(Invenergy Trade Secret Cannon Falls Proposal and Strategist Data); Ex. 46 (Wishart Direct)at 23.

[79] Geronimo itself acknowledges that the rate it used to calculate the value of avoided transmission capacity - MISO's existing rate for network integration service - is an average cost rate for service, not a marginal cost for additional transmission capacity. Ex. 61 (Beach Rebuttal) at 8-9. The use of this crude proxy to estimate the cost of the avoided capacity associated with Geronimo's proposal further undercuts Geronimo's claim that any such adjustment should be made.

[80] Geronimo Initial Brief at 25-26.

Cannon Falls.[81] To reduce Geronimo's rate impact to be a least cost alternative comparable to those natural gas units, Geronimo's net present value payments would have to be reduced by nearly 20% ($34 million divided by $186 million = 18.3%).

2. *Modeling was Not Biased*

Geronimo asserts that the Company's Strategist modeling inappropriately favored the natural gas proposals. Geronimo first objects that the Company allowed the Strategist model to treat each of the three units in the Company's and Invenergy's proposals individually.[82] The reason the Company did this is because the terms of the proposals allowed the units to be selected individually by the Commission.[83] They were therefore modeled accordingly.

Geronimo also objects that the credit capacity the Company used in its Strategist modeling unfairly favored the natural gas proposals.[84] To the contrary, the capacity credit was used so that a facility like Calpine's Mankato expansion would not be unfairly disfavored because of its larger capacity.[85]

Moreover, the capacity credit in and of itself plainly had no substantial impact on Strategist's ranking of the resources. The Department did not use the capacity credit methodology to account for the higher capacity and efficiency of the Mankato expansion and arrived at the same relative ranking of the resources as did the Company.[86]

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[81] Ex. 46 (Wishart Direct) at 35, Table 8 (showing the $34 million PVSC impact on total system costs of the resource portfolio adding Geronimo to the system on top of Black Dog Unit 6 and Cannon Falls).

[82] Geronimo Initial Brief at 21.

[83] See Ex. 1 (Company Proposal) at 1-3 to 1-4; Ex. 46 (Wishart Direct) at 40-41; Ex. 25 (Invenergy Cannon Falls Proposal); Ex. 26 (Invenergy Hampton Corners Proposal).

[84] Geronimo Initial Brief at 21-23.

[85] Ex. 46 (Wishart Direct) at 17.

[86] Ex. 86 (Rakow Rebuttal) at 13-14.

Finally, Geronimo objects that the generic solar units in the Strategist modeling were priced below Geronimo's proposed units, while the generic CTs and CCs were priced above the CT and CC units proposed by the Company, Invenergy, and Calpine. As explained in the testimony of Mr. Wishart, the pricing for the generic solar and generic gas units was based on internal Company information from across its jurisdictions.[87]

Furthermore, with regard to the natural gas generic units, it is correct that they were priced somewhat higher than the cost of the actual bids received for Black Dog Unit 6, Mankato, and Cannon Falls. This is not surprising since generic units are necessarily priced as greenfield construction, resulting in somewhat higher costs. The three natural gas proposals are brownfield expansions, however, and therefore are predictably cheaper than building at a new site.

Thus the treatment of generic units in the model is not based on any favoritism but rather on the proposals submitted and the market price information the Company had in hand. And as noted above, Geronimo did not introduce any evidence in the record to call the Company's cost information for solar units into question.

3. Renewable Energy Preference

Geronimo spends a great deal of time in its brief arguing about Minnesota's preference for renewable resources. Geronimo concludes, incorrectly, that this preference necessarily means that Xcel Energy is 'required' to select the solar proposal irrespective of all other circumstances. While Xcel Energy is committed to expanding renewable energy portfolio, solar generation is not the best resource to meet the potential need established in this Docket.

There is no question that the Geronimo proposal will comply with the environmental requirements of Minnesota law. But based on the record in this

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[87] Hrg. Tr. Vol. I at 109-110.

proceeding, so will Black Dog Unit 6, and the Cannon Falls and Mankato expansion projects.[88] The question is whether Minnesota's statutory preferences for renewable energy require Geronimo to be selected rather than Black Dog Unit 6, Cannon Falls, or Mankato.

Minn. Stat. § 216B.243, subd. 3a calls for the Commission in a certificate of need proceeding to consider whether the Company has "explored the possibility of generating power by means of renewable energy resources and has demonstrated that the alternative selected is less expensive (including environmental costs) than power generated by a renewable energy source." Thus to be favored over a nonrenewable resource Geronimo's solar generation proposal had must be a least-cost alternative, and as discussed above it is not.

In addition, Minn. Stat. § 216B.2422, subd. 4 provides that the Commission shall not approve a nonrenewable resource unless the Company demonstrates that a renewable resource is not in the public interest. Contrary to the claims of Geronimo and the Environmental Intervenors, the record evidence supports the determination that the selection of Geronimo's proposal to meet our potential need is not in the

[88] *See generally* Environmental Report- Xcel Competitive Resources Acquisition Proposals (Oct. 2013). Minn. Stat. § 116D.04, subd. 6 does not alter this conclusion, as the Environmental Intervenors suggest in describing the statute as "prohibiting approval of activities that would cause pollution where 'feasible and prudent alternatives' exist and stating that 'economic considerations alone shall not justify such conduct.'" Environmental Intervenors Initial Brief at 5, n.10. Alternatives need only be considered when there is a prima facie showing that the proposed state action will cause "pollution, impairment or destruction" of natural resources within the state. *Iron Rangers for Responsible Ridge Action v. Iron Range Resources*, 531 N.W.2d 874, 882 (Minn. Ct. App. 1995) *rev. denied* (Minn. July 28, 1995). "Pollution, impairment or destruction" is defined as violating an environmental quality standard, limitation, rule, order, license, stipulation agreement, or permit, or materially adversely affecting the environment. Minn. Stat. §§ 116D.04, subd. 1a(b)(incorporating the definition provided in Minn. Stat. § 116B.02, subd. 5). There is no such prima facie showing with respect to any of the proposals in this proceeding, nor could there be given the record evidence indicating all the proposals will meet applicable facility permitting requirements. *See also In re Application for Air Emission Facility Permit*, 566 N.W.2d 98, 105 (Minn. Ct. App. 1997) (there can be no finding of material adverse environmental effects where a facility will comply with all applicable state and federal permitting standards).

public interest.[89] While the Company is obligated to obtain this energy at the least cost possible, the record evidence discussed previously indicates Geronimo's proposal is not least cost.

As it stands, the record in this proceeding supports the conclusion that Geronimo's proposal is priced above market compared to dispatchable natural gas capacity. As discussed in Section V.C.2 above, while Geronimo objects to this conclusion, it did not provide any evidence to the contrary. It is clear from the Strategist analysis conducted by both the Company and the Department that the Geronimo proposal is not least cost.

Geronimo, as well as the Environmental Intervenors, minimize the cost premium associated with Geronimo's proposal on the grounds that the premium is "minor" and does not outweigh the renewable energy benefits of the proposal.[90] As explained above, Xcel Energy disagrees with the conclusion that the solar proposal's price premium is inconsequential; it is substantially more expensive than the resources that the Company and the Department are recommending to meet the Company's potential need, and the rate impact of the solar proposal is relatively large in comparison to its size. For purposes of filling the need identified in this proceeding, the lowest-cost natural gas proposals are in the public interest.

4. *Non-Cost Reasons for Not Selecting Geronimo*

In addition to economics, there are non-cost reasons supporting the decision not to choose the Geronimo solar proposal. Taken together, these reasons support the conclusion that selecting that proposal on this record would not be in the public interest.

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[89] Geronimo Initial Brief at 35; Environmental Intervenors Initial Brief at 5-7.

[90] Geronimo Initial Brief at 25-26; Environmental Intervenors Initial Brief at 7-8.

Under the solar mandate, the Company is required to add approximately 290 MW of solar generation to its system by 2020.[91] Xcel Energy fully intends to comply with that mandate and is taking steps to probe the market for reasonably-priced solar resources. In order to meet our public interest obligation of buying reasonably priced solar resources, it is important to understand the market and the available competition prior to making the purchase. Otherwise, the Company cannot know whether the cost is reasonable compared to other solar alternatives.

Whether or not Xcel Energy purchases solar generation in this proceeding, Xcel Energy will, in the long term, purchase the 290 MW of solar generation required by the mandate. If Xcel Energy purchases solar resources through this proceeding, we will count those resources toward the mandate and the 100 MW Geronimo proposal would use up one-third of our required solar purchase. We do not believe it is in the public interest to fill such a large proportion of the mandate without probing the solar market to determine whether the pricing put forward by Geronimo is higher or lower than other solar proposals. On the other hand, if Xcel Energy does not purchase solar resources in this proceeding, it will still fulfill its 290 MW mandate, but will do so through targeted RFPs that foster competition among solar proposals designed to elicit the lowest-priced solar resources.

Under these circumstances, it would contrary to the public interest to nevertheless select Geronimo's 100 MW solar proposal to meet one third of our obligations under SES when there is no evidentiary support for a finding that the proposal is cost-effective in comparison to other solar options that could meet the requirements of the mandate.[92] For this reason we continue to recommend that Geronimo's solar proposal is more appropriately considered in an upcoming solar solicitation where it can be compared against other solar energy proposals so we can

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[91] Ex. 46 (Wishart Direct) at 22.

[92] Ex. 46 (Wishart Direct) at 36; Ex. 83 (Rakow Direct) at 11.

adequately confirm that we are obtaining solar generation at the lowest possible price.[93] An all-solar RFP could be issued for projects of a size and timing determined in our next resource plan as approved by the Commission.[94]

VI. RESOURCE SELECTION PROCESS

A. Resource Selection Recommendation

The Department recommends the Commission identify Black Dog Unit 6 and the Calpine and Invenergy expansion projects as the pool of resources to meet the Company's need, with the Commission's final selection of two of the three based on the outcome of the Company's PPA negotiations with Calpine and Invenergy.[95] Calpine, Invenergy, and Geronimo, however, each believe they should be selected by the Commission to meet the Company's need before PPA negotiations begin, and that the PPA negotiation process should not be competitive.[96]

The Company generally agrees with the Department's approach except that it does not believe there is any need to wait until the end of the PPA negotiation phase to select Black Dog Unit 6 as one of the two resources. Black Dog Unit 6 is included in all of the top 20 plans in the Company's Strategist analysis because it is the optimum resource in terms of both low cost and flexibility of implementation.

We also have proposed a MERP-style cost recovery method that will incentivize the Company to avoid capital cost increases while simultaneously offering customers the opportunity to share in any savings the Company realizes. We believe

[93] Ex. 46 (Wishart Direct) at 36. The Department also proposes this approach. Department Initial Brief at 63.

[94] *Id.*

[95] Department Initial Brief at 57.

[96] Calpine Initial Brief at 31-32; Invenergy Initial Brief at 56-58; Geronimo Initial Brief at 31-34.

this is the best overall proposal for our customers.[97] Alternatively, we do not object to the Department's proposal that we be held to the capital costs in our proposal and then be allowed to realize all of the benefits of any savings. Finally, we are a rate regulated utility, and as such our Black Dog Unit 6 does not raise the construction, operation, maintenance, financial accounting, and financial security risks that need to be addressed in the PPA negotiations with Invenergy and Calpine, and which could affect the pricing of their projects.

B. Competitive PPA Negotiations

The Company continues to support its proposal to undertake simultaneous negotiations with Invenergy and Calpine to develop the proposal that is the best interests of our customers. The Department also supports this approach as a reasonable way to select the project "with terms most favorable to ratepayers."[98]

Calpine, Invenergy and Geronimo appear to recognize that simultaneous negotiations shifts negotiating leverage away from the project and in favor of our customers by putting pressure on the project to negotiate more ratepayer-friendly terms than its competitors in order to advantage their ultimate selection. Their self-serving objections to the Company's and Department's proposal to have a competitive PPA negotiations are three-fold: (i) competitive PPA negotiations constitute a change in the Track 2 process; (ii) such negotiations would discount the record evidence developed in the proceeding; and (iii) such negotiations lack transparency, creating the risk that the Company unilaterally makes the resource determination through the PPA negotiation process rather than the selection being

[97] Ex. 49 (Alders Direct) at 6; Xcel Energy Initial Brief at 3. In addition, we included our estimates of the fixed and variable O&M costs for Black Dog Unit 6 in Table C3a in Appendix C of our proposal. These costs will be subject to prudence review and disallowance as is the O&M costs for all Company-owned generating units.

[98] Department Initial Brief at 62.

made openly by the Commission. These concerns are all misplaced and, to the contrary, the negotiation process unquestionably result in better terms for our customers than if Xcel Energy is required to negotiate a PPA with a single "winner" as that winner will have little incentive to accept ratepayer-friendly terms.

Track 2 Process. First, there is no significant change being proposed to the Track 2 process. Track 2 provides that the Commission makes a determination based on the evidentiary record developed in the contested case as to which of the resource proposals will proceed to PPA negotiations with the Company. Under Track 2, the Company and the selected vendor have four months to come to terms on a PPA, after which the PPA is brought to the Commission for review and approval. That process has not been modified in the least by negotiating multiple PPAs simultaneously.

The only difference being proposed here is that two resource proposals should move forward to the PPA negotiation phase. This is because the evidentiary record shows that there is no clear winner between Calpine and Invenergy. The record supports a finding that either the Calpine Mankato and Invenergy Cannon Falls expansions could be a reasonable choice to complement Black Dog Unit 6. The choice between them is so close that it is likely that the final terms of the PPAs could influence the Commission's final choice between them. The outcome of those negotiations will inform the Commission's choice of the better project to be included in this resource selection.

Delay or Termination Provisions. Second, the competitive PPA negotiations will address the very same issues that would be addressed if there was only one resource in the negotiations, namely, what are the final PPA terms and conditions upon which the resource proponent and the Company can agree. The only difference here is the competitive nature of the process. Each of Calpine and Invenergy will know that the other is also negotiating similar terms, which will put pressure on them to optimize the value of their proposal in order to win the final contract. As the Department observes, the competitive pressures of the process will ensure that the Company as well as Calpine and Invenergy keep the interests of our customers foremost in mind in the course of the negotiations.

The type of issues that will need to be addressed in negotiations will certainly have the potential to sway the selection. Several of the issues could have a material impact on the value of the PPA sufficient to swing the Commission's decision one way or another. The amount and terms of the required security fund can have an impact on the value of PPA proposals to our customers. Further, the specifics surrounding the availability of the unit and financial consequences for poor performance are generally customized in negotiations and could influence the relative value of the proposals.

The uncertainties surrounding the ultimate level of the need to be filled will guide our PPA negotiations. To mitigate those uncertainties, we will attempt to negotiate two contractual mechanisms to give us added flexibility: (1) the option to delay the proposed in-service date; and (2) the option to cancel the PPA if the Commission subsequently finds that the need no longer justifies proceeding with that project. Each of these issues will require individual negotiation that we anticipate will include discussion over whether such clauses would require payments or price changes. Knowing that the Company is negotiating similar concepts with the other bidder should encourage each to make its very best proposal to capture the contract. Far from lacking transparency (as argued by Geronimo) this process will inject healthy competition in the negotiation phase and should increase the transparency of the costs to be incurred by our customers.

In our experience negotiating PPAs, we generally find that PPA vendors are reluctant to agree to an option to delay the in-service date without compensation. We acknowledge that Invenergy agreed on the record to move the in-service date of the

Cannon Falls project from 2016 to 2017 with no price change, and move the project's in-service date to 2018 or 2019 with revised pricing.[99] Calpine has proposed revised pricing if its project's proposed in-service date in 2017 is moved to 2018 or 2019.[100] But these commitments do not necessarily answer the question of whether the vendor could allow us to make a subsequent change in the in-service date and what compensation might be required for that flexibility.

For example, if the proposed in-service date for the PPA project is 2017 and the Commission decides we should delay implementation until 2019 because of declining need, the PPA must provide for the right to delay the in-service date and specify the terms and compensation surrounding such delay. At a minimum, we expect that the vendors will ask for recognition of the time-value of the delay. But because the vendor is facing competition, it could act as an incentive for the vendor to keep its compensation request as low as possible.

Likewise, the option to terminate the PPA prior to commercial operation will raise significant issues in the negotiations that will benefit from competition between Invenergy and Calpine. In order to obtain financing or to expend significant capital in furtherance of the project, PPA vendors generally require that their contractual obligations become fixed upon receipt of Commission approval. In other words, once the Commission approves the PPA, the vendor knows that Xcel Energy cannot walk away from the contract (absent a vendor breach or other extraordinary circumstance) and the vendor has reasonable assurances it will recover its investment.

If an early termination clause is negotiated, the Company anticipates it would have to include compensation in the form of a make-whole payment or break-up fee. Depending upon the timing of the termination, that cost could be significant. Again,

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[99] Ex. 69 (Ewan Rebuttal) at 4; *see also* Ex. 87 (Rakow Nonpublic Rebuttal Attachments), Attachment SR-R-9 at 4.

[100] Ex. 87 (Rakow Nonpublic Rebuttal Attachments), Attachment SR-R-9 at 5-6.

having competition available during these negotiations should help mitigate the amount and terms of a break-up fee which should ameliorate the impact on customers.

Transparency. Finally, the claim that our proposed negotiation process lacks transparency ignores that fact that the final PPAs will be subject to Commission scrutiny and approval. We contemplate the Commission's PPA review and approval process will involve a comment period during which all parties to the proceeding will be able to examine the terms of the PPAs and comment on which PPA is in the best interests of our customers.[101]

Thus there is no opportunity for the Company to make any determinations unilaterally or behind closed doors. To the contrary, competitive negotiations will require the Company to deal in good faith with both parties to reach the best terms that can be agreed to for the benefit of our customers. The Company's execution of this obligation will then be subject to review by the Commission, with the Department and the two competing parties themselves providing the Commission their point of view on whether the process was appropriately handled by the Company.

At the end of this process, the Commission will determine which PPA should be selected in combination with Black Dog Unit 6 to proceed forward. Because the PVSC of the Mankato and Cannon Falls expansion projects are so similar, our proposal is that the PPA that offers the best value should be selected.

[101] To the extent to which trade secret information is contained in a PA, the current Protective Order could be used to address access to such information.

VII. CONCLUSION

The Commission should select Black Dog Unit 6 to meet the potential need in combination with either the Mankato or the Cannon Falls expansion project. Both Calpine and Invenergy should be directed to proceed to the PPA negotiation phase to determine which of the Mankato and Cannon Falls expansion projects provides the PPA with the best value for our customers. If neither proceed past the negotiation phase, the Commission should select our Red River Valley Unit 1 to meet our need in combination with Black Dog Unit 6.

Further, the Commission should order a process that allows the Company to report in 2014 and 2015 about any changes in the need for additional capacity. If warranted, the Company should be allowed to defer or cancel one or both of the selected projects depending upon the actual need at the time.

Finally, for the Black Dog Unit 6 proposal, the Commission should adopt the Company's MERP-style cost recovery approach. In the alternative, the Commission could accept the Department's alternative cost-recovery method for Xcel Energy's project.

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Respectfully submitted,

By /s/ *James Denniston*

James R. Denniston
Assistant General Counsel
NORTHERN STATES POWER COMPANY, a Minnesota corporation
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401
Telephone: (612) 215-4656

Michael C. Krikava
Thomas Erik Bailey
BRIGGS AND MORGAN, PA
2200 IDS Center
Minneapolis, MN 55401
Telephone: (612) 977-8566

ATTORNEYS FOR NORTHERN STATES POWER COMPANY