

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

*In the Matter of Petition of Northern States Power Company to
Initiate a Competitive Resources Acquisition Process*

MPUC Docket No.: E-002/CN-12-1240
OAH Docket No.: 8-2500-30760

Exhibit No.: ____ (PJH-1)

**DIRECT TESTIMONY OF
PAUL J. HIBBARD**

ON BEHALF OF CALPINE CORPORATION

September 27, 2013

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I. INTRODUCTION

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Q. Would you please state your name, business address, and occupation?

A. My name is Paul Hibbard. I am a Vice President at Analysis Group, Inc. (AGI), an economic, finance and strategy consulting firm headquartered in Boston, Massachusetts, where I work on energy and environmental market, policy, and strategy consulting. My business address is 111 Huntington Avenue, 10th Floor, Boston, Massachusetts 02199.

Q. Please describe your background and experience.

A. I have been with AGI for almost seven years since 2003. First, from 2003 to April 2007, and most recently, from August 2010 to the present. In between, from April 2007 to June 2010, I served as Chairman of the Massachusetts Department of Public Utilities (DPU). While Chairman, I also served as a member of the Massachusetts Energy Facilities Siting Board, the New England Governors' Conference Power Planning Committee, and the NARUC Electricity Committee and Procurement Work Group. I also served as State Manager for the New England States Committee on Electricity and as Treasurer to the Executive Committee of the 41-state Eastern Interconnect States' Planning Council.

From 2000 to 2003 I worked in energy and environmental consulting with Lexecon, Inc.. Prior to working with Lexecon, I worked in state energy and environmental agencies for almost ten years. From 1998 to 2000, I worked for the Massachusetts Department of Environmental Protection on the development and administration of air quality regulations, State Implementation Plans and emission control programs for the electric industry, with a focus on criteria pollutants and carbon dioxide

1 (CO₂), as well as various policy issues related to controlling pollutants from electric
2 power generators within the Commonwealth. From 1991 to 1998, I worked in the
3 Electric Power Division of the DPU on cases related to the restructuring of the electric
4 industry in Massachusetts, the setting of company rates, the quantification of
5 environmental externalities, integrated resource planning, energy efficiency, utility
6 compliance with state and federal emission control requirements, regional electricity
7 market structure development, and coordination with other states on electricity and gas
8 policy issues through the staff subcommittee of the New England Conference of Public
9 Utility Commissioners.

10 I hold an M.S. in Energy and Resources from the University of California,
11 Berkeley, and a B.S. in Physics from the University of Massachusetts at Amherst. My
12 curriculum vitae is attached as Exhibit No. __ (PJH-2).

13 **II. PURPOSE AND SUMMARY OF TESTIMONY**

14 **Q. What is the purpose of your testimony?**

15 A. The purpose of my testimony is to provide a quantitative and qualitative
16 comparative evaluation of proposals currently before Xcel Energy (Xcel or the Company)
17 and the Minnesota Public Utilities Commission (Commission) to meet the estimated 500
18 megawatts of Xcel's forecasted capacity and energy need for the 2017 to 2019 timeframe.
19 In particular, I have been asked by Calpine to compare the proposals for thermal
20 generation capacity from Xcel, Invenergy, and Calpine. I compare these proposals from
21 the perspectives of (1) ratepayer impacts on an equivalent levelized cost of electricity
22 (LCOE) basis; (2) public policy, resource mix and system operations; and
23 (3) considerations with respect to ratepayer risks.

1 **Q. Would you please summarize your findings?**

2 A. Yes. This is a unique time for Xcel's procurement of additional capacity
3 resources; one that requires careful consideration of costs to ratepayers as well as energy
4 and environmental policy; changing requirements for the generating fleet and emerging
5 operational needs; and ratepayer risks associated with different asset ownership or
6 contracting arrangements.

7 I have analyzed, from the perspective of Xcel's ratepayers, the levelized cost of
8 electricity of the thermal resources offered in this procurement by Xcel, Invenergy, and
9 Calpine. Using conservative assumptions regarding unit capacity factors (CF) and other
10 financial and operational factors, Calpine's Mankato bid represents the best value for
11 ratepayers by a wide margin, and under a wide range of assumptions.

12 In addition, significant changes to industry circumstances will have important
13 consequences for Xcel's resource needs, system operations, and long-run costs.
14 Emerging controls on carbon at existing power plants are a real possibility, making
15 attention to existing resource attrition, the opportunities for economical supply of electric
16 energy and capacity, and the emission rates and efficiency of new resources particularly
17 important. Renewable standards and goals will change the operational requirements of
18 the power grid in a time frame relevant to this procurement, increasing the need for
19 resources that can continuously and economically offer operational flexibility across all
20 hours of the year, and do so without diluting – from an emissions perspective – the
21 environmental objectives of Minnesota's Renewable Energy Standard. The potential
22 retirement of long-standing baseload resources in addition to unforeseen market-related
23 or operational problems may require substitution with capacity that can play a similar

1 baseload and/or intermediate role. And new utility contracts or investment in this context
2 can carry significant and different ratepayer risks associated with exposure to
3 development, cost and operational factors that should be considered carefully by Xcel
4 and the Commission.

5 Attention to these issues suggests the Commission should ensure that resource
6 decision making be disciplined by a level playing field, competition, and a fair, equal and
7 transparent assessment of resource alternatives. Attention to ratepayer risks in turn
8 suggests that all bidders should be held to cost recovery tied to specific prices, terms and
9 conditions submitted with their offers, and the Commission should carefully review the
10 different risk profiles of offered projects.

11 In consideration of all of these key factors – a comprehensive and transparent
12 analysis of the levelized cost of electricity of resources competing in this procurement;
13 the operational, efficiency, and environmental benefits of combined cycle technology
14 relative to competing alternatives; and the value in shielding ratepayers from certain
15 development, cost and operational risks – I conclude that Calpine’s Mankato facility
16 should be among the resources selected in this acquisition process.

17 **Q. How is your testimony organized?**

18 In Section III, I summarize my calculations with respect to the LCOE for each of
19 the Xcel, Invenenergy and Calpine proposals, including analytic method, assumptions,
20 underlying data, scenarios reviewed, and results. In Section IV, I identify key public
21 policy considerations, aspects of Minnesota’s power system, and the operational and
22 environmental characteristics of the thermal energy generating capacity proposed in this
23 solicitation (that is, combined cycle (CC) and combustion turbine (CT) technologies) that

1 should be considered in evaluating proposals in this procurement. Finally, in Section V, I
2 address important considerations related to ratepayer risk, and the need for heightened
3 attention to the different risk factors presented by resources bid into this procurement.

4 **III. LEVELIZED COST OF ELECTRICITY**

5 **Q. Is it possible to construct an analysis that provides a clear and transparent**
6 **comparison of proposals from the perspective of electric ratepayers?**

7 A. Yes. It is not only possible, but it is critically important that a robust and
8 transparent quantitative analysis of bids be considered by the Commission. One way to
9 do this is through a levelized cost of electricity analysis, in which the capacity, energy,
10 and other cost elements in project proposals are translated into an equivalent dollars-per-
11 megawatt hour (MWh) metric, using consistent financial, market, and temporal
12 assumptions across all proposals.

13 **Q. What is the value of carrying out a LCOE calculation, and how have you**
14 **approached the LCOE analysis in this instance?**

15 A. In this docket the Commission is being asked to choose from among multiple
16 resources with different terms, cost elements, technologies, and operational utilization
17 factors. Most importantly, the projects in this solicitation differ in at least two
18 fundamental ways. First, they include both firm power purchase agreement (PPA)
19 proposals from merchant generators (with twenty-year terms, specific price points, and
20 operational guarantees) and self-build project cost estimates from the incumbent utility
21 (with life-of-asset terms, an incentive ratemaking proposal, and no operational
22 guarantees). A comparison of bids under these circumstances must include a clear and

1 transparent demonstration of how assumptions related to the different terms and payment
2 structures affect the expected cost and value of different bids.

3 Second, the proposals in this solicitation include projects whose use in daily
4 operations is fundamentally different from the standpoint of frequency, duration, and
5 timing of commitment and dispatch. That is, CTs will have a very different operational
6 profile and use (infrequent, short-duration operations) than that of CCs (frequent, long-
7 duration operations). A comparison of bids under these circumstances must include a
8 clear and transparent demonstration of how expectations or assumptions regarding
9 resource use affect the expected cost and value of different bids.

10 A LCOE analysis is able to capture these fundamental differences in a transparent
11 manner, and enables a relatively straightforward and consistent comparison of bids.
12 Below, I present a LCOE analysis I conducted for the thermal energy generating
13 resources offered in this solicitation. My purpose for and approach to the LCOE analysis
14 was to construct a fully independent, objective, and transparent analysis that treats all
15 offers on an equal and fair basis. However, since I am a witness for Calpine in this
16 proceeding, I took an expressly conservative approach to the evaluation of Calpine's bid;
17 that is, wherever there was uncertainty in bid or financial parameters, or the need to apply
18 subjective judgment in analytic assumptions, I selected values that tend to disadvantage
19 Calpine's proposal relative to other offers in this procurement.

20 The LCOE metric for each proposal represents the net present value of the
21 expected annual costs – including variable and fixed operation and maintenance costs,
22 capital costs, and the return on investment – divided by annual generation over the term
23 of the proposal. The LCOE calculation establishes annual costs in accordance with

1 contract terms (in the case of PPAs), or using traditional calculations of annual revenue
2 requirements (in the case of utility self-build units), creating comparability across such
3 structural differences in proposal pricing and asset lives. In addition, the LCOE analysis
4 accounts for differences in utilization between resource types through variable capacity
5 factor inputs that determine average annual generation.¹ LCOE analysis is an accessible
6 and useful representation of the ultimate impact to ratepayers, against which any other
7 analyses may and should be compared.

8 **Q. Xcel and the Department of Commerce will be using Strategist to compare**
9 **proposals in this proceeding. Is it your view that Strategist modeling is not useful?**

10 A. No. Strategist can be a useful tool for considering at a high level and from a long-
11 term resource planning perspective the potential implications of different resource
12 combinations over time. However, Strategist has a number of limitations that need to be
13 considered when interpreting results and comparing proposals in this proceeding. In
14 particular, the Strategist model may fail to capture operational details that could be
15 important in understanding the relative value of CC versus CT technologies on the
16 Company's system, in particular as the level of variable renewable generation on the
17 Company's system increases.² As Xcel Energy noted in its 2010 Resource Plan, the
18 Strategist model has limitations, in that it "...loses the ability to capture some operational
19 detail, such as the ramp rates on our generating units..." and "...uses a simplified

¹ The LCOE analysis compares ratepayer impacts of each proposal under a user-specified set of capacity factor assumptions. However, it does not include dispatch simulation, and thus it does not quantify the economic and environmental benefits of displacing generation. Ignoring such benefits would tend to underestimate the value of CC capacity relative to CT capacity, since the more efficient and more highly-utilized CC capacity would likely generate greater price and emission displacement than CT capacity.

² Xcel Energy has recognized the operational uncertainty associated with growing integration of wind on its system. See, e.g., Xcel Energy, "2010 Resource Plan" (hereafter, "Resource Plan"), Minnesota Public Utilities Commission Docket Number E002/RP-10-825, August 2, 2010, at p. 4-8.

1 approach to modeling load and wind patterns.”³ In effect, as variable renewable
2 resources become a major contributor to generation, the dispatch model used in Strategist
3 may not be well-suited to understanding how units will be committed and/or operated to
4 manage potential variations in wind and solar output (and thus net load), particularly over
5 the shortest timeframes (i.e., on the order of seconds to tens of minutes) when on-line
6 resources will be needed to follow load and provide regulation service. The greater the
7 level of net load variability due to renewable resource integration, the less confidence one
8 should have in Strategist results with respect to the operations of CT and CC
9 technologies.

10 I do not mean, however, to suggest that the Commission should not closely
11 review and consider Strategist modeling results. To the contrary, the decision made in
12 this proceeding will affect ratepayer costs, risks, and system operations/reliability for
13 decades. Given the importance of this decision, the Commission should carefully
14 consider all of the modeling and analyses presented by parties in the proceeding. I only
15 mean to suggest that the Commission should keep in mind that Strategist is a proprietary
16 “black box” model, one whose unit commitment and dispatch module is opaque and
17 admittedly simplistic, in ways that are clearly of heightened importance in comparing
18 technologies offered in this procurement. One value of the LCOE analysis I present is
19 that it provides a fully transparent and straightforward assessment of the cost of proposals
20 to ratepayers in a manner that provides the Commission with an additional analytical tool
21 to inform its decision.

³ Resource Plan at p. 4-10.

1 Q. Could you please provide a summary of the results of the LCOE analysis you
2 conducted?

3 A. Yes. I estimated the LCOE for the bids using data contained in each proposal
4 with respect to capital costs, energy costs, operating costs, financing costs, and pollutant
5 emissions provided by each company. To complete the analysis, I made a number of
6 additional operational and financial assumptions, which I summarize below. Key results
7 are presented in Figure 1 below and in Exhibit No. __ (PJH-4), and include the following:

- 8 • Calpine’s Mankato proposal offers the lowest LCOE across all gas-fired bids at
9 [TRADE SECRET INFORMATION BEGINS TRADE SECRET
10 INFORMATION ENDS].
- 11 • The Invenergy Hampton and Cannon Falls bids are the most expensive gas-fired
12 options. The LCOE for each bid is in excess of [TRADE SECRET
13 INFORMATION BEGINS TRADE SECRET INFORMATION
14 ENDS].
- 15 • Xcel’s Black Dog bid is the lowest cost option among the CT proposals. The
16 LCOE for Black Dog - which accurately replicates Xcel’s revenue requirement
17 estimate for the Black Dog unit – is [TRADE SECRET INFORMATION
18 ENDS] TRADE SECRET INFORMATION ENDS].⁴

⁴ Xcel estimated a revenue requirement of [TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]. See Xcel Energy, “Application to the Minnesota Public Utilities Commission for Approval of a Competitive Resource Acquisition Proposal and for a Certificate of Need, Appendix C” (hereafter, “Appendix C”), Minnesota Public Utilities Commission Docket No. E002/CN-12-1240, April 15, 2013, at p. C-5.

1

[TRADE SECRET INFORMATION BEGINS

Figure 1

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TRADE SECRET INFORMATION ENDS]

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- This finding is robust to a range of assumptions (discussed below)⁵ and scenarios,

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including:

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- *Changes to discount rate and inflation rate* – the base case is calculated using an inflation rate of 2.36 percent, and a discount rate of 7.47 percent; I also reviewed results at inflation and discount rates of 2 percent and 5 percent, respectively.

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- *Changes to assumed capacity factors* – as discussed below, and presented in Exhibit No. __ (PJH-5), results can vary as a function of assumed (or realized) CFs of the resources. In the base case I assume [TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS] capacity factor for CTs, and 20 percent capacity factor for CCs. In the alternative capacity factor scenario, I review the results assuming capacity factors for CTs and CCs based on

⁵ Exhibit No. __ (PJH-3) includes a full list of model assumptions and inputs.

1 actual CFs realized by these technologies on Xcel’s system over the past
2 three years.

- 3 ■ *Changes to assumed PPA term length* – In the base case, I assume bid
4 terms for the PPAs (20 years), and the depreciation life assumed for the
5 Xcel proposals (35 years). To test the sensitivity of results to difference in
6 term lengths, I also analyze results with the PPA term lengths extended to
7 35 years, holding constant the pricing terms.
- 8 ■ *Changes to cost overruns and Xcel’s Return on Equity (ROE)* – In the
9 base case, I assume Xcel’s self-build costs are equal to their estimates; in
10 this scenario, I assume that Xcel’s costs come in ten percent under budget
11 (and with appropriate adjustments to investment ROE for the first five
12 years).
- 13 ■ *Changes to estimated starts per turbine and related dispatch payments* –
14 In the base case I assume 125 starts for CCs, and 75 starts for CTs. In this
15 scenario I assume 75 starts for both technologies.
- 16 ■ *Technology controls* – In this scenario, I assume that CTs are required to
17 install selective catalytic reduction (SCR) technology to minimize
18 emissions in the same manner as CC technology; this adds approximately
19 \$15 million (2017 dollars), and lowers nitrogen oxide (NO_x) emission
20 rates to 2.5 parts per million.
- 21 ■ *CO₂ Emissions* – In this scenario I add a CO₂ cost to all resource
22 emissions at \$21.50 per ton, escalating annually at the inflation factor.
- 23 ■ *Non-Firm Fuel Service* – In the base case, I price natural gas
24 supply/transportation on a firm basis for all bids in order for them to
25 qualify as year-round capacity resource, and to allow a level playing field
26 analysis of all resources. In this scenario, I allow the Invenergy CT
27 capacity to operate on non-firm natural gas supply/transportation bases.
28

29 The results under each of these scenarios are summarized in Exhibit No. __ (PJH-

30 4). In short, under nearly every way to analyze the LCOE of proposals in this
31 proceeding, against a wide range of potential future power system and financial
32 conditions, and using assumptions (where needed) that conservatively overstate
33 Mankato’s costs or understate competitors’ costs, Calpine’s Mankato proposal offers
34 substantial benefits from a ratepayer’s perspective relative to the other bids in this
35 solicitation. In particular, even using estimates of resource utilization that would
36 seriously understate the value of Mankato relative to competing CT proposals, Mankato
37 is the clear winner. Specifically, assuming average annual capacity factors of [TRADE

1 **SECRET INFORMATION BEGINS** **TRADE SECRET INFORMATION**
2 **ENDS]** for CT units and 20 percent for the Mankato CC unit (my selection of these
3 capacity factors is described below), the LCOE of Mankato is 42 percent less than the
4 next closest proposal (Xcel’s Black Dog CT), and 46 percent to 59 percent less than all
5 other bids that I evaluated. At average annual capacity factor assumptions that are higher
6 than 20 percent for the Mankato unit, or lower than **[TRADE SECRET**
7 **INFORMATION BEGINS** **TRADE SECRET INFORMATION ENDS]** for CTs
8 – both likely outcomes for reasons that I discuss later in this testimony – Mankato’s
9 advantage from a LCOE perspective increases.

10 **Q. Could you please summarize the key assumptions in the LCOE analysis?**

11 A. Yes. First, the bids (and associated Strategist Assumption Documents) were the
12 source of all data used in the analysis for items specified in the proposals, such as unit
13 size, availability, capacity payments or costs, energy pricing, start costs, contract term,
14 and plant emission rates. Second, where possible I used financial and fuel cost
15 assumptions consistent with those used by Xcel in recent Strategist analyses, or for
16 ratemaking purposes, or provided by Xcel in responses to interrogatories in this
17 proceeding. Finally, where for the purpose of LCOE calculations I needed to identify
18 inputs that could not be found in proposals, interrogatories, or Xcel Strategist/rate
19 documentation, I applied commonly-used industry data and assumptions. Specific key
20 assumptions for the base case, and sources for those assumptions, include the following
21 (more detail on the assumptions and calculation methods is included in Exhibit No. __
22 (PJH-3)):

- 1 • For the *Discount Rate* I applied the weighted average after-tax cost of capital of
2 7.47 percent used by Xcel Energy for modeling analysis in the 2010 Resource
3 Plan;⁶
4 • Where I apply an *Inflation Rate* to nominal values that are not expressly bid with
5 an escalation factor, I use 2.36 percent, consistent with the general inflation rate
6 applied in the Sherco Life Cycle Management analysis;⁷
7 • For *Gas Prices*, I relied on information provided in this docket. Specifically, I
8 used the total gas costs calculated using the original and supplemental responses
9 to IR DOC-42 and later updated in IR-CAL-10 for firm service to each of the
10 Calpine, Xcel and Invenergy bids.⁸ For the annual demand charge for the Xcel
11 bids, I relied on the Strategic Assumptions Documents;
12 • For variable costs associated with pollutant emissions, I used prevailing market
13 prices for allowances of sulphur dioxide (SO₂) and NO_x;
14 • For capacity factors, I assumed [**TRADE SECRET INFORMATION BEGINS**
15 **TRADE SECRET INFORMATION ENDS** for CTs, and 20 percent for
16 CCs (discussed further below).
17

18 **Q. Xcel Energy suggests in its Response to IR DOC-42 that the Commission may elect**
19 **to allow non-firm natural gas transportation service for CT units (but not CC units),**
20 **given their expected lower level of utilization. Do you believe that would be an**
21 **appropriate assumption for your analysis?**

22 A. No I do not; this would not allow for a comparison across bids with all resources
23 on the same level playing field. First, the purpose of this solicitation is to procure
24 capacity to meet Xcel Energy’s capacity obligations as a load-serving entity within the
25 Midcontinent Independent System Operator (MISO) system. Consequently, the capacity
26 procured in this resource acquisition must have the same meaning with respect to being
27 available to meet Xcel Energy’s capacity supply obligations, and reliably serve Xcel’s

⁶ Resource Plan at p. 4-2.

⁷ Xcel Energy, “Life Cycle Management Study for Sherburne County (Sherco) Generating Station Units 1 and 2” (hereafter, “Sherco Study”), Minnesota Public Utilities Commission Docket Number E002/RP-13-368, July 1, 2013, at D-8.

⁸ Xcel Energy response to the Department of Commerce, Supplement to Information Request No. 042, Docket E002/CN-12-1240, June 28, 2013, at p. 5. Xcel Energy response to Calpine Corporation, Information Request No. 010, Docket E002/CN-12-1240, August 20, 2013, at p. 2.

1 customers on a year-round basis. As Xcel notes in its response to IR DOC-42, however,
2 allowing interruptible natural gas transportation service would mean *less reliable service*,
3 noting that under these conditions the Commission “...should expect the plants to be
4 unable to operate on most cold winter days due to interruption of gas transportation
5 services...”⁹ While CT units may operate mostly when nearing peak-load conditions,
6 they also may be relied upon in winter months, and must be available to operate year-
7 round in response to contingency events or otherwise as needed to meet system reliability
8 needs. This may be particularly true under system conditions that require CTs to balance
9 the state’s increasing penetration of intermittent renewable resources, or otherwise
10 require CT operation at higher CFs than realized historically. Further, while it is true that
11 there is *generally* sufficient natural gas transportation during summer months when
12 demand is highest, this cannot be guaranteed. Should there be flow restrictions due to a
13 pipeline outage, maintenance, or other gas system condition, a customer that has firm
14 transportation service will always have priority over one that does not. In order for the
15 proposals submitted in this procurement to be evaluated on a comparable, apples-to-
16 apples basis, the same assumptions and pricing inputs for natural gas transportation
17 service should be used for all bids. Consequently I use the estimated cost of firm service
18 for all bids in the base case LCOE analysis.¹⁰

⁹ Xcel Energy response to the Department of Commerce, Supplement to Information Request No. 042, Docket E002/CN-12-1240, June 28, 2013, at p. 5.

¹⁰ As noted above, I also evaluate LCOE assuming non-firm service for the Invenergy facilities. While this changes the LCOE for the Invenergy bids, the difference is not significant, and does not alter my conclusions based on the LCOE analysis. For example, changing natural gas pricing to a non-firm basis for the Cannon Falls facility decreases its LCOE from [TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS], which is still [TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS] higher than the result for the Mankato facility keeping Mankato on firm natural gas service and holding all other base case assumptions constant.

1 **Q. Is this the only issue of comparability related to natural gas supply that needs to be**
2 **considered in project evaluation?**

3 A. No, it is not. One issue the Commission may want to consider to ensure
4 comparable bid evaluation is how Xcel Energy positions its mix of existing natural gas
5 commodity and transportation arrangements and incremental fuel procurement practices
6 with respect to proposal evaluations. The result of this procurement may include some
7 mix of natural gas-fired generation, including capacity constructed and operated by Xcel,
8 Invenergy, or Calpine, or some combination thereof. But regardless of who owns the
9 capacity procured, the responsibility for procurement of natural gas commodity and
10 transportation will fall to Xcel, since the Invenergy and Calpine bids are tolling
11 agreements. Consequently, for any thermal resource selected in this procurement, the
12 new need for natural gas will be folded into Xcel’s overall natural gas procurement
13 strategy, which is designed to optimize the use of existing and new commodity, storage,
14 and transportation assets, contracts, and spot purchases for use of natural gas in all owned
15 and tolling contract resources.¹¹ To its credit, Xcel has appropriately recognized this
16 fact, noting in response to Calpine Information Request No. 12 that “the demand cost to
17 have firm gas transportation to the Calpine Mankato site uses a one time discounted
18 expansion that NSP negotiated in the past. The cost of the expansion is irrelevant as NNG
19 is obligated to provide the expansion at the discounted rate.”¹² For the purpose of
20 resource evaluation in the current procurement, this means that the *only* differences that

¹¹ See, Xcel Energy, “Fuel Acquisition and Risk Management Plan” (hereafter “Xcel Fuel Plan”), Minnesota Public Utilities Commission Docket Number E002/RP-10-825, July 1, 2013, at pp. 22-36 for a discussion of Xcel’s coordinated approach to gas supply for owned assets and tolling agreements.

¹² Xcel Energy response to Calpine Corporation, Information Request No. 012, Docket E002/CN-12-1240, August 20, 2013, at p. 1.

1 should be assumed with respect to gas supply and transportation pricing for competing
2 bids are known incremental investments specifically needed to meet gas transportation
3 needs that are unique to a given facility’s location (as well as any differences in local
4 transportation costs in delivering natural gas to each unit).

5 **Q. Please describe your approach to assigning capacity factors to resources for the**
6 **purpose of the LCOE analysis.**

7 A. As noted above, capacity factors can have a significant impact on the LCOE of
8 competing proposals, and so need to be considered carefully in the context of estimating
9 proposal value in this procurement. Ultimately, the annual average capacity factors that
10 would be realized for the facilities in question will depend on a number of key factors,
11 including (1) the potential for the retirement of existing resources, which could
12 dramatically and differentially affect the CFs for resources that are competing in this
13 solicitation; (2) the level of new variable resource integration in and around Xcel’s
14 service territory, and how that affects the need for on-line load-following service and the
15 use of intermediate and baseload capacity; and (3) the contractually guaranteed heat rates
16 of competing proposals, and how they compare to the heat rates of other resources on the
17 system.

18 In my base case LCOE analysis, I assume annual average CFs of [**TRADE**
19 **SECRET INFORMATION BEGINS** **TRADE SECRET INFORMATION**
20 **ENDS]** for CT units based on the CF presented by Xcel Energy in its Strategist
21 Assumption Document.¹³ Based on a review of historical CF data presented in the Xcel
22 Fuel Plan, this may overstate the CF for CTs. Table 4 in the Xcel Fuel Plan shows that

¹³ Appendix C at p. C-3.

1 the vast majority of CFs for natural gas-fired CT units from 2010 through 2012 were
2 between 1 and 3 percent in each year.¹⁴

3 In my base case LCOE analysis, I assume a 20 percent annual average CF for
4 Calpine’s Mankato facility, which I believe is lower than what would actually occur, for a
5 number of reasons. First, Calpine’s proposal provides for a guaranteed heat rate of

6 **[TRADE SECRET INFORMATION BEGINS**

7
8 **TRADE SECRET INFORMATION ENDS]** Consequently, if

9 selected in this procurement, one would expect the Mankato proposed facility to be
10 committed and dispatched as often, or nearly as often (and thus have a CF on the same
11 order as) the most efficient CC units on the system. Table 4 in the Xcel Fuel Plan shows
12 that Xcel’s two most efficient CC units (High Bridge and Riverside – **[TRADE**

13 **SECRET INFORMATION BEGINS**

14 ¹⁵ **TRADE SECRET INFORMATION ENDS]** operated at 37 percent
15 and 44 percent CF in 2012, and between 14 percent and 23 percent in 2010 and 2011.
16 My choice of 20 percent for a CC CF is less than the three year average CF (25 percent)
17 for these two plants over the 2010-2012 period. Of course, to the extent that over the
18 next several years emerging CO₂ and other Environmental Protection Agency (EPA)
19 requirements lead to the retirement of additional baseload coal-fired generation, I would
20 expect the role and CFs of CC units on Xcel’s system – particularly the most efficient,

¹⁴ Xcel Fuel Plan at p. 23. Only 2 out of 15 entries for CT units between 2010 and 2012 were above 3 percent (yet still less than **[TRADE SECRET INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**) – 5 percent for Blue Lake and 4 percent for Cannon Falls, both in 2012.

¹⁵ SNL Financial reports a heat rate of 7,203 for High Bridge in 2012 and a heat rate of 7,275 for Riverside in 2012.

1 highest heat rate units – to expand significantly relative to past performance and current
2 expectations.

3 **Q. Why are expectations regarding the CFs of CC and CT units so important in**
4 **valuing the proposals in this procurement?**

5 The addition of low heat rate, high-efficiency CC capacity on Xcel’s system
6 would generate significant savings for Xcel’s ratepayers (and reductions in emissions)
7 through displacement of less efficient, higher-emitting resources in many hours.¹⁶ If only
8 CT capacity is chosen – instead of CC capacity – the opportunity to generate these
9 marginal energy cost savings would be lost. Consequently, the value to ratepayers of CC
10 versus CT capacity varies significantly based on annual average CF expectations for each
11 proposed unit. In addition, a straightforward impact of higher capacity factors is to
12 spread the higher fixed costs of CC capacity across a greater number of hours, thereby
13 reducing the realized LCOE. The specific impact on the LCOE of competing proposals
14 is depicted graphically in Figure 2 (below) and Exhibit No. __ (PJH-5), which show the
15 LCOE in \$/MWh for each bid as a function of capacity factors. For example, at the
16 intersection of the horizontal and vertical dashed lines in Figure 2, you see that at a CF of

17 **[TRADE SECRET INFORMATION BEGINS TRADE SECRET**
18 **INFORMATION ENDS]**, the LCOE for the Black Dog facility is **[TRADE SECRET**
19 **INFORMATION BEGINS TRADE SECRET INFORMATION ENDS]**.¹⁷

20 Following the horizontal dashed line to the right, you see that the Calpine Mankato
21 facility’s LCOE is equal to Black Dog’s at a CF of approximately 8 percent, and *always*

¹⁶ Importantly, as noted above, the LCOE analysis I present in this testimony does *not* capture the cost and emission benefits that stem from displacement of less-efficient, higher-emitting resources. All else equal, I would expect that inclusion of such benefits would improve the value of Mankato relative to the CT units offered in this procurement.

¹⁷ Black Dog is used in this example because it is the next most cost-effective proposal.

1 lower than this at CFs above 8 percent. In other words, if the Black Dog CT is modeled
2 at a [**TRADE SECRET INFORMATION BEGINS** **TRADE SECRET**
3 **INFORMATION ENDS**], Mankato will always be more cost effective at any CF above
4 8 percent than Black Dog (or any other proposed CT, as can be seen in Exhibit No. __
5 (PJH-5)). Furthermore, as can be seen in Exhibit No. __ (PJH-5), at any CF greater than
6 approximately 14 percent, the Mankato proposal will always be the most cost-effective
7 option on a \$/MWh basis compared to any proposed CT operating at the same, or lower,
8 CF.

9 **[TRADE SECRET INFORMATION BEGINS**

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11 **Figure 2**

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22 **TRADE SECRET INFORMATION ENDS]**

1 Q. At utilization rates for CTs and CCs similar to those actually experienced in 2012,
2 how would the proposals in this procurement compare?

3 A. Figure 2 also can be used to consider how the LCOE of competing proposals
4 varies as a function of expected annual average CFs. For example, if one assumes the
5 Black Dog CT achieves a CF of not [TRADE SECRET INFORMATION BEGINS
6 TRADE SECRET INFORMATION ENDS], but 5 percent – equal to the 4
7 maximum CF for a CT in 2012 – its LCOE increases from [TRADE SECRET
8 INFORMATION BEGINS TRADE SECRET
9 INFORMATION ENDS] to approximately [TRADE SECRET INFORMATION
10 BEGINS TRADE SECRET INFORMATION ENDS]. This can be seen
11 by following the red line in Figure 2 from [TRADE SECRET INFORMATION
12 BEGINS TRADE SECRET INFORMATION ENDS] to 5 percent (along
13 the X axis), and seeing how this changes the intersection with levelized cost (along the Y
14 axis). The lower the CF value, the steeper the curve; this illustrates the large difference
15 CF assumptions make in changing the LCOE of the proposed unit. In contrast, if one
16 assumes the Mankato CC achieves a CF of not 20 percent, but 44 percent (moving to the
17 right along the X axis for the blue line) – equal to the maximum CF for a CC in 2012 – its
18 LCOE decreases from [TRADE SECRET INFORMATION BEGINS
19 TRADE SECRET INFORMATION ENDS]. Consequently, the difference
20 between the Mankato and Black Dog bids at these values (44 percent and 5 percent,
21 respectively) increases from [TRADE SECRET INFORMATION BEGINS
22 TRADE SECRET INFORMATION ENDS] to approximately [TRADE
23 SECRET INFORMATION BEGINS TRADE SECRET

1 **INFORMATION ENDS]** based only on assuming annual average capacity factors that
2 are more in line with actual experience at best-performing CT and CC units in 2012.

3 **Q. What conclusions do you draw from your review of LCOEs under different**
4 **assumptions about CFs for CT and CC units?**

5 A. It is clear that expectations about annual average CFs are a major factor in
6 comparing the cost to ratepayers of the proposals submitted in this procurement.
7 Consequently, of paramount importance is that the Commission carefully consider what
8 its expectation is about future utilization of the resources bid into this procurement, in
9 consideration of unit efficiency relative to the existing resource mix, potential future
10 retirements, likely evolution of system load and operations, and Minnesota’s energy
11 policy goals. Based on my LCOE analysis, it appears that one has to expect highly
12 unrealistic CFs of 8 percent or less for Mankato – which if selected would likely be
13 among the most efficient and highly-utilized CC facilities on the Company’s system –
14 and 6 percent CFs for CT units in order to conclude that it is not in ratepayers interests to
15 include Mankato among the winning resources stemming from this procurement.

16 **IV. REGULATORY AND RESOURCE MIX CONSIDERATIONS**

17 **Q. In your view, are there important considerations relative to this procurement with**
18 **respect to federal and state energy and environmental regulation and policy?**

19 A. Yes, there are a number of federal and state policies and regulatory efforts that
20 could significantly affect Xcel’s resource mix and that, while uncertain at this time, need
21 to be carefully considered when reviewing proposals in this procurement, especially
22 when considering the 35 (or more) year useful lives of any new capacity resources. This
23 includes, in particular, the implementation of Minnesota’s existing greenhouse gas goals

1 and potential for new federal requirements to control CO₂ from power plants, and policies
2 to foster the significant expansion of variable renewable resources. The importance of
3 these considerations is heightened by the fact that any thermal resources selected in this
4 procurement may be the only such resources added to Xcel's system between now and
5 close to the end of the decade, at which point system mix and operational needs could be
6 very different from today.¹⁸

7 **Q. What is important to consider regarding CO₂ emissions?**

8 A. Resource planning and procurement always occur in the presence of uncertain
9 forecasts of, for example, electrical load growth; resource performance, addition, and
10 attrition; fuel prices; and the like. This resource planning process is no different – all
11 elements of load growth, fuel pricing, and resource additions are based on assumptions
12 and forecasts that may turn out to be wrong. But in one sense the current context is
13 unique – perhaps the most important uncertainty that needs to be wrestled with is how to
14 think about what current and potential CO₂ control requirements mean for resource
15 selection in the current procurement. Xcel's Sherco study highlights the importance of
16 considerations related to CO₂ control requirements, in that assumptions related to CO₂
17 control and pricing are the strongest influence on the wisdom of various capital
18 investment strategies.¹⁹

19 While efforts to pass national CO₂ legislation stalled in Congress over the past
20 few years, the state of Minnesota, the White House, and EPA all have implemented
21 and/or are continuing to develop regulations or policies to control emissions of CO₂, and

¹⁸ This assumes that the next resource acquisition process would not result in a procurement of resource offers until sometime in 2015 or 2016, and that the lead time between procurement and operation is on the order of three to four years.

¹⁹ Sherco Study at p. 2.

1 achieve meaningful CO₂ reductions. In particular, President Obama’s Administration and
2 EPA are clearly heading down a path that would require states to address emission of
3 CO₂ from existing electric generating facilities, with compliance timeframes that could
4 become relevant within the first few years of operation of the resources that will be
5 selected in this procurement. The State of Minnesota also has set CO₂ reduction goals
6 that become meaningful within this time frame– the Next Generation Energy Act of 2007
7 (effective August 1, 2007) called for cutting greenhouse gas (GHG) emissions, setting a
8 target of reducing Minnesota’s GHG to 15 percent below 2005 emission levels by 2015,
9 30 percent by 2025, and at least 80 percent by 2050.²⁰

10 **Q. Could you please summarize the most important EPA initiative with respect to**
11 **potential CO₂ control requirements?**

12 A. Yes. As Xcel Energy notes in its Life Cycle Management Study for Sherco, EPA
13 is expected to issue a proposal for GHG rules for existing power plants that may require
14 the filing of State Implementation Plans in 2016, and compliance three (2019) to five
15 (2021) years after this.²¹ While the prospects of national GHG legislation or regulation
16 have historically been frustrated or delayed by political disagreements and legal
17 challenges, current circumstances are different in fundamental ways. This administration
18 and EPA have made it clear that this is a high priority over the next two years. Further,
19 action by the administration follows major rulings by the U.S. Supreme Court and the
20 U.S. Court of Appeals for the District of Columbia Circuit upholding EPA’s authority to
21 regulate CO₂ as a pollutant under the Clean Air Act.²²

²⁰ Next Generation Energy Act of 2007, Article 5, Section 2, Subdivision 1.

²¹ See, e.g., Sherco Study at pp. 22-23.

²² See, e.g., Sherco Study at p. 21.

1 On June 25, 2013, President Obama announced sweeping measures to reduce
2 greenhouse gas pollution. In part, the President announced that he would use his
3 executive powers to require reductions in the amount of carbon dioxide emitted by the
4 nation’s power plants.²³ The Presidential Memorandum containing this Plan directs the
5 EPA to “work expeditiously to complete carbon pollution standards for both new and
6 existing power plants.”²⁴ For existing power plants, the Memorandum calls for EPA to
7 issue proposed carbon pollution standards, regulations, or guidelines, for modified and
8 existing power plants by no later than June 1, 2014 and issue final standards, regulations,
9 or guidelines, by no later than June 1, 2015.²⁵ The carbon reductions at power plants are
10 the centerpiece of a three-pronged Climate Action Plan that will also involve new federal
11 funds to advance renewable energy technology, and support mitigation.²⁶ Following this,
12 on September 20, 2013, EPA released its proposed New Source Performance Standard
13 (NSPS) rules to regulate CO₂ emissions from new power plants.²⁷ EPA has also
14 committed to working with states and stakeholders to develop emission guidelines for
15 existing power plants and, in accordance with the Presidential Memorandum, “...will
16 issue proposed standards for existing power plants by June 1, 2014.”²⁸

²³ Landler, Mark. “Obama Outlines Ambitious Plan to Cut Greenhouse Gases,” The New York Times, June 25, 2013 (hereafter “Landler”). Available at http://www.nytimes.com/2013/06/26/us/politics/obama-plan-to-cut-greenhouse-gases.html?pagewanted=all&_r=0.

²⁴ “The President’s Climate Action Plan,” Executive Office of the President, June 2013, accessed 9/23/2013. Available at <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

²⁵ “Presidential Memorandum – Power Sector Carbon Pollution Standards,” The White House Office of the Press Secretary, accessed 9/23/2013. Available at <http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards>.

²⁶ Landler.

²⁷ Environmental Protection Agency, “EPA Proposes Carbon Pollution Standards for New Power Plants” (hereafter, “EPA News Release”), News Release, September 20, 2013. Available at <http://yosemite.epa.gov/opa/admpress.nsf/0/da9640577ceacd9f85257beb006cb2b6!OpenDocument>.

²⁸ EPA News Release.

1 In some sense, EPA is now obligated to move forward with controls on existing
2 power plants. With its release of the proposed NSPS for CO₂ from new power plants, it
3 has initiated a proceeding that may lead to a final NSPS rule. Promulgating the final
4 NSPS rule would then trigger section 111(d) of the Clean Air Act – a provision that
5 requires EPA and the states to create performance standards to limit emissions from
6 existing power plants.²⁹

7 **Q. Why is the move towards meaningful controls on emissions of CO₂ from existing**
8 **power plants important in the procurement at issue in this proceeding?**

9 A. While now, in 2013, the potential for regulations and policies to control CO₂
10 emissions (as well as the potential for a further tightening of national ambient air quality
11 standards and other environmental requirements) that would take effect in or around 2020
12 may seem distant, it is not at all distant in the context of this acquisition process. It is
13 directly relevant to this procurement because the resources selected in this process will
14 not be in operation until just one to three years prior to 2020. The resources chosen will
15 thus have a direct bearing on both the difficulty and cost Minnesota faces in achieving
16 compliance with various requirements, and the options and flexibility Minnesota has with
17 respect to changes in the mix of resources and the GHG intensity of its power sector.
18 Since roughly a third of Xcel Energy’s resource portfolio (in terms of both capacity and
19 energy) is coal-fired baseload resources, the availability of other resources that could
20 operate as baseload or intermediate resources in this timeframe needs to be considered in

²⁹ “Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act: Options, Limits, and Impacts,” Nicholas Institute for Environmental Policy Solutions Report, NI R 13-01, January 2013, at p.5. Available at http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

1 the selection of resources in the current procurement cycle.³⁰ In this context, the
2 selection of CC technology rather than or at least in addition to CT technology provides a
3 hedge against the risk that increasingly stringent control requirements lead to greater than
4 expected retirements of baseload coal-fired capacity since CC capacity can operate in
5 baseload and intermediate roles (whereas CT technology is not well-suited for this
6 purpose). In particular, adding CC capacity at this time will increase the flexibility that
7 Xcel and the Commission have to consider the implications of potential retirements due
8 to environmental requirements or unforeseen market or operational circumstances.

9 **Q. Please explain the context for growth in variable renewable resources in and around**
10 **Xcel Energy’s service territory.**

11 A. In 2012, wind generation represented 11 percent of Xcel’s resource mix, a number
12 that is expected to grow substantially over the next decade.³¹ Minnesota has
13 implemented aggressive programs to promote the development and acquisition of new
14 renewable resources. Specifically, through legislation in 2007 and 2013 Minnesota
15 enacted a renewable energy standard (RES) requiring that renewable electricity amount
16 to 31.5 percent of Xcel’s retail electricity sales in Minnesota by the end of 2020, with at
17 least 25.5 percent coming from wind (24 percent) and solar (1.5 percent) resources.³²
18 Similar requirements are in place for other electricity providers in Minnesota. While
19 Minnesota has in place other incentives for the development of renewables (e.g., net

³⁰ Sherco Study at p. 7. It should also be noted that Xcel may not be able to rely on transactions with neighboring regions to help, should compliance raise resource mix challenges. MISO as a whole is heavily reliant on coal-fired baseload resources, and has identified potential retirement of such resources due to EPA requirements only (that is, not accounting for potential CO₂ requirements) as a risk to maintaining planning reserve margins. Potomac Economics, “2012 State of the Market Report for the MISO Electricity Markets,” June 2013 at pp. 16-17.

³¹ Sherco Study at p. 7.

³² “Minnesota incentives/Policies for Renewables & Efficiency, Renewables Portfolio Standard,” DSIRE, accessed 9/2/2013. Available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN14R.

1 metering), the RES will have by far the most significant impact on utility-scale variable
2 renewable development over the next decade.

3 **Q. Why is the level of renewable development important for this procurement?**

4 A. This level of variable renewable integration has both reliability and environmental
5 implications that should be considered by the Commission. With respect to reliability,
6 Xcel Energy has noted that the Minnesota RES requires a penetration of wind on its
7 system that is at the limits of what was studied from a reliability standpoint in the
8 Minnesota Wind Integration Study; and that Xcel remains unsure about the impacts of
9 variable renewable integration on its system.³³ Of course, Xcel and Minnesota are not
10 alone in needing to consider the potential implications of integrating a vast amount of
11 variable resources in system operations – but at a level of almost a third of the energy
12 generated to meet customer demands on an annual basis, new variable resources will
13 likely have a significant impact on the commitment and dispatch, economics, and
14 emissions of the remainder of the generating fleet used to serve Xcel’s load. In this
15 respect, the choices made in this procurement can either support or frustrate the
16 operational and environmental objectives of integrating variable renewable resources.

17 The challenge of supporting integration of variable resources covers time spans of
18 seconds to minutes to hours to days. The significant increase in net load variability due
19 to wind/solar forecasting uncertainty and variability in output that will be in play by 2020
20 – within a couple years of when this procurement’s resources will come on line – will
21 require adjustments in commitment and dispatch decisions across all time scales. Both
22 CT and CC technologies are effective in responding from on- or off-line states to

³³ Resource Plan at p. 4-8.

1 expected variations in load that occur over several hours or more. Further, both on-line
2 CCs and on- or off-line CTs can effectively be used to respond to sudden system events
3 for which recovery is needed on the order of tens of minutes or hours, such as the loss of
4 generation or transmission resources, or errors in daily demand forecasts or variable
5 generation output. Finally, on-line CCs can effectively be used as a load-following or
6 regulation resource for net load variations on the order of minutes and tens of minutes.
7 While CTs are effective in managing changes that need to be responded to on the order of
8 tens of minutes or more, the CT proposals in this proceeding may require [**TRADE**
9 **SECRET INFORMATION BEGINS** **TRADE SECRET**
10 **INFORMATION ENDS**] advance notice time.³⁴

11 **Q. What are the environmental implications associated with balancing renewable**
12 **resources that should be considered in the context of this procurement?**

13 A. The most obvious policy goal of the RES in Minnesota is to meet customer load
14 on a going-forward basis with reduced emissions and other environmental impacts. The
15 Commission should consider how the selection in this procurement may affect the degree
16 to which Minnesota meets this policy objective. To the extent thermal generating
17 resources are selected in this solicitation, it will be either only CT resources, only CC
18 resources, or some combination of the two, at a time when Xcel will be integrating – and
19 balancing from an operational perspective – vast amounts of variable renewable
20 resources consistent with the RES. Thus the task of balancing the increased net load

³⁴ Invenenergy, “Cannon Falls Peaking Expansion” Minnesota Public Utilities Commission Docket Number E002/CN-12-1240, April 15, 2013, at p. 12; Invenenergy, “Hampton Energy Center” Minnesota Public Utilities Commission Docket Number E002/CN-12-1240, April 15, 2013, at p. 12; Xcel Energy, “Application to the Minnesota Public Utilities Commission for Approval of a Competitive Resource Acquisition Proposal and for a Certificate of Need” (hereafter “Xcel Petition”), Minnesota Public Utilities Commission Docket Number E002/CN-12-1240, April 15, 2013, at p. 1-12.

1 variability of the system will fall in part to the resources selected at this time. To the
2 extent that CT resources are selected over CC resources in this procurement, the
3 environmental impacts of the increased need to balance the integration of RES resources
4 will be worse. This would be a perverse outcome given that the overall goal of promoting
5 renewable energy is to ensure an environmentally responsible energy mix.

6 **Q. Please explain how the environmental impacts may be worse.**

7 A. The relative impact of CT versus CC technologies from an emission perspective is
8 presented in Exhibit Nos. __ (PJH-6a) and (PJH-6b). This exhibit shows emission rates
9 from each unit proposed in this solicitation on a pounds per MWh (lb/MWh) basis. In
10 other words, the exhibit provides a true apples-to-apples environmental comparison of the
11 projects with respect to the level of emissions that result from production of an equivalent
12 amount of energy. The emission rates for the Mankato facility are lower than the next-
13 closest option by [TRADE SECRET INFORMATION BEGINS

14 **TRADE SECRET INFORMATION ENDS]** for nitrogen oxides (NO_x),
15 and [TRADE SECRET INFORMATION BEGINS

16 **TRADE SECRET INFORMATION ENDS]** for CO₂. These emission rates are
17 primarily a direct function of the relative energy efficiency (i.e., heat rates) of the
18 respective projects; in simple terms, using less fuel per MWh results in less air pollution
19 per MWh. With respect to NO_x, the differential is also due to the fact that Mankato
20 includes back-end emission control technology that is not included in the CT bids.

21 **Q. Are there policy options that could help at least partially mitigate this outcome?**

22 A. Yes. First, the selection of the Mankato bid would help counter this potentially
23 perverse outcome, by ensuring that the most efficient, lowest-emission resource capable

1 of balancing variable renewable resources is added to the system. In addition, the
2 Commission should consider the value of mitigating the environmental impacts of CT
3 capacity used to help manage net load variability by requiring the installation of state-of-
4 the-art selective catalytic reduction (SCR) technology on any CT resources that succeed
5 in this procurement, and that the costs of that equipment – which are small relative to the
6 overall costs of CT proposals in this procurement – be included in the economic
7 evaluation of the bids.³⁵ Failure to do so would place Mankato at a competitive
8 disadvantage, and would, in effect, punish Mankato for being a cleaner option.
9 Considering the policy objectives of Minnesota’s RES and other efforts to address power
10 plant emissions, this requirement would help create a more level playing field from an
11 emissions perspective for the resources under consideration and evaluation in this
12 procurement. Relying on any argument that such equipment is not necessary strictly from
13 a permitting perspective may be appropriate for a project that is being considered on a
14 stand-alone basis, but would be shortsighted and contrary to the obvious state policy
15 objectives associated with truly integrated resource planning efforts in the context of a
16 comparative evaluation of new capacity resources.

17 **Q. Would you please summarize your conclusions regarding important considerations**
18 **related to the policy and resource mix context in this proceeding?**

19 A. Yes. The Commission should carefully consider the combination of the potential
20 requirements related to emissions of CO₂ from existing power plants, the environmental
21 objectives of Minnesota’s RES, and the vast quantity of variable renewable resources that

³⁵ Based on recent study for the PJM Interconnection, I estimate the cost of SCR installations on CT technology to be on the order of \$15 million in 2017 dollars for a unit roughly the size of the CTs proposed in this procurement. This is a fraction of the capacity costs of the CT proposals. Brattle Group with CH2M Hill, "Cost of New Entry Estimates For Combustion-Turbine and Combined-Cycle Plants in PJM," August 24, 2011, Table 20 at p. 20.

1 will need to be integrated and balanced over time frames relevant to the resource
2 procurement in this proceeding. All of these factors point to a fundamental change in the
3 power system of Xcel and its neighbors; changes that could involve a significant
4 reduction in existing baseload (coal-fired) capacity and substantially greater net load
5 variability for many hours of the year and across all time frames – from on the order of
6 seconds to days, in all seasons of the year, and in all times of the day. This type of
7 system needs or will benefit from additional capacity that (1) is flexible; (2) is responsive
8 to all balancing authority operating needs; (3) is available to help manage net load
9 variability and uncertainty across all time frames; (4) is designed to operate continuously
10 and/or frequently, across many hours of the year and under many different system
11 conditions; and (5) is able to help integrate and balance a large amount of variable
12 renewable resources at relatively high efficiency and low emission rates.

13 **Q. What do you believe this implies for the resource selection at this time?**

14 A. Both CT and CC capacity are effective in helping to manage net load variability
15 and integrate a quickly growing portfolio of renewable resources, across a wide range of
16 time frames of interest. However, considering the policy objectives and resource mix
17 risks discussed above, combined cycle capacity – in particular Calpine’s Mankato
18 proposal – is perfectly suited to meet these needs, ranging from efficiently helping
19 manage renewable resource integration to cost-effectively filling in as intermediate or
20 baseload capacity should existing baseload capacity retire. Further, Calpine has offered
21 the Mankato facility at a highly competitive price which, as is discussed in Mr.
22 Thornton’s testimony, takes advantage of the project’s unique economies of scale.

1 Mankato, therefore, is both an economic and environmentally-appropriate resource for
2 Xcel and its customers.

3 While Xcel may want to also add CT capacity to its system, I believe it would be
4 a mistake to add CT capacity only, or to the exclusion of the Mankato facility. CT
5 capacity is not designed to operate frequently or continuously, at high capacity factors,
6 and thus may not be ideal in light of the policy and resource mix considerations discussed
7 above. And while CT capacity can come on line fairly quickly, it is not ideal for
8 balancing net load variability economically across many hours of the year, in all seasons,
9 and can not always be on line to help balance such variability on a second-to-second or
10 minute-to-minute basis, to the extent that becomes an important operational concern.
11 Finally, the relatively high heat rate and high emission rates of CT capacity relative to CC
12 capacity mean that the cost and environmental impact of using only CT capacity to
13 balance renewable generation would be counterproductive to the purpose of Minnesota's
14 RES and other economic and environmental objectives.

15 **V. CONSIDERATIONS RELATED TO RATEPAYER RISKS**

16 **Q. In light of the fact that the proposals being reviewed by the Commission in this**
17 **proceeding result from a competitive process, why do you think it is important to**
18 **comment on ratepayer risks as part of your testimony?**

19 A. I want to focus in this last section of my testimony on the question of who bears
20 the risk of utility decisions, rather than whether processes (such as competitive
21 procurements) lead to efficient outcomes for consumers.

22 Clearly, I recognize that for many years, the Commission has understood the
23 value of competitive procurements as an important – essential – part of the electric

1 utility’s resource planning and supply strategy. I note, for example, the Commission’s
2 statement in 2006 that the “purpose of the competitive process – getting the best overall
3 price for ratepayers – cannot be achieved without robust competition.”³⁶ The
4 Commission recognized that competition in the generation sector could result in greater
5 efficiency in power production and lower costs to consumers.³⁷

6 The goal of obtaining “the best overall price for ratepayers” relies not only on
7 competition to allow for discovery of the best offer prices from suppliers, but it also
8 depends upon discovering and weighing any differences in the risk profile of the
9 competitive offers. Price is certainly one aspect of getting the best deal for ratepayers;
10 the development status and the terms and conditions under which a product is proposed at
11 a particular price also affects the relative value of different competitive offers to
12 consumers.

13 **Q. Please explain further what you mean by the impact on consumers of the terms and**
14 **conditions under which a product is supplied.**

15 A. We see this relative “risk” principal at work all the time in the electric industry.
16 Utilities must make decisions at one point in time about investments and other
17 commitments that could be greatly affected by events that will occur much later, and
18 which may or may not comport with the original expectations. Development uncertainty
19 can lead to delays, changes in costs, and unexpected outcomes. Labor and material costs
20 change. Fuel prices change. Public policy changes. Consumer habits change. Countless

³⁶ Minnesota Public Utilities Commission, “Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, Subd. 5, And Requiring Compliance Filing ‘In the Matter of Northern States Power Company d/b/a Xcel Energy’s Application for Approval of its 2004 Resource Plan’” (hereafter “Resource Acquisition”), Minnesota Public Utilities Commission Docket Number E-002/RP-04-1752, May 31, 2006, at p. 6.

³⁷ Resource Acquisition, at p. 2.

1 things can change, so that – after the fact – the original decision to select a particular
2 power plant may end up looking like a very good deal or a bad failure. These conditions
3 – variations in development status, open versus guaranteed pricing, and uncertain versus
4 guaranteed performance – are exactly what is before the Commission in the instant case.

5 **Q. In your view, does Calpine’s proposal appropriately manage the risks related to new**
6 **resource acquisition?**

7 A. Yes. The risk profile, from the perspective of ratepayers, is different for the
8 different offers made in response to this solicitation. Xcel, for example, seeks a cost-
9 recovery arrangement under which the supplier (Xcel) passes through to ratepayers the
10 actual dollars of power plant investment (into utility rate base), with the allowed return
11 for the investment conditioned to a limited extent, and for only the first five years, on
12 how the actual costs compare to project estimates.³⁸

13 By contrast, Calpine has offered a proposal under which it bears all of the risk
14 associated with construction and operating cost overruns.³⁹ In effect, the Commission
15 knows now with a high level of certainty what ratepayers will pay over time for power
16 from the Mankato proposal, and what performance Calpine is obligated to provide from
17 the perspectives of capacity availability and operational performance. This is because in
18 addition to proposing a specific offer price, Calpine has included heat rate and
19 availability guarantees as part of its proposal.⁴⁰ Also, as discussed above, CC generation
20 is a less risky proposition from a long-term market perspective because it more

³⁸ Xcel Petition, at p. 4-14.

³⁹ Calpine Corporation, “Mankato Energy Center Expansion Proposal,” (hereafter “Mankato Proposal”) Minnesota Public Utilities Commission Docket No. E002/CN-12-1240, April 15, 2013 at p. 4.

⁴⁰ Mankato Proposal, Appendix B at p. 2.

1 effectively hedges against uncertainty related to environmental policy, fuel price
2 forecasts (due to CC’s greater energy efficiency) and longer-term market trends.

3 In short, compared to other offers in this procurement, from the perspective of
4 ratepayers, Calpine’s proposal can be viewed as a low risk proposition that hedges
5 ratepayer risk, via the terms of a binding contract, to the maximum extent possible. In my
6 view this constitutes a meaningful difference in proposal attributes and allocation of risk,
7 which should be factored into the Commission’s decisions about which offers provide the
8 best “price” and “value” to ratepayers.

9
10 **VI. CONCLUSION**

11 **Q. Would you please summarize your testimony in this proceeding?**

12 A. Yes. In summary, consideration of a range of economic, operational and
13 environmental factors supports approval of Calpine’s Mankato bid to meet at least part of
14 Xcel’s current resource need.

15 With respect to economic considerations, Mankato is the least expensive option
16 among the thermal energy resources offered in this procurement by Xcel, Calpine, and
17 Invenergy. This conclusion appropriately relates to long-term costs, based on the
18 levelized cost of electricity, as seen from the perspective of Xcel’s ratepayers. Using
19 conservative assumptions regarding unit capacity factors and other financial and
20 operational factors, Calpine’s Mankato bid represents the best value for ratepayers by a
21 wide margin, and under a wide range of assumptions, especially when delivered fuel
22 costs (i.e. firm fuel for Cannon Falls and Hampton) and installation of equivalent
23 emission controls (i.e. SCR for all CT projects) are evaluated on a level playing field

1 compared with Mankato. Moreover, the Mankato CC proposal clearly exceeds the
2 operational value of the CT bids that have been proposed with respect to energy
3 production, environmental performance and overall operational flexibility.

4 Environmental performance is particularly important given the role any new
5 thermal generation resource will play in terms of meeting state and federal policy goals
6 and complementing the state’s rapid growth of intermittent renewable generation.
7 Indeed, even if the bids were deemed to be equivalent based on an economic analysis, the
8 environmental attributes of CC generation would overwhelmingly tip the scale in favor of
9 the Mankato proposal.

10 Renewable standards and goals will change the operational requirements of the
11 power grid in a time frame relevant to this procurement, increasing the need for resources
12 that can continuously and economically offer operational flexibility across all hours of
13 the year, and do so without diluting – from an emissions perspective – Minnesota’s well
14 established environmental objectives. The potential retirement of long-standing baseload
15 resources due to environmental regulation or other factors may require substitution with
16 capacity that can play a similar baseload and/or intermediate role. In short, any and all
17 new thermal generation resources that are developed to meet future capacity needs, hedge
18 against potential retirements, and balance the state’s increasing dependence on clean
19 renewable resources should use the cleanest type of fossil fuel technology that is
20 currently available. Combined cycle generation will always be preferable from an
21 emissions standpoint due to heat rate considerations. While CTs cannot match the energy
22 efficiency benefits of CC generation, Minnesota should at least consider requiring
23 commercially available emissions controls on any future CT projects.

1 Attention to these issues suggests the Commission should ensure that resource
2 decision making be disciplined by a level playing field, robust competition, and a fair,
3 equal and transparent assessment of resource alternatives. Attention to ratepayer risks in
4 turn suggests that all bidders should be held to cost recovery fully tied to specific prices,
5 terms and conditions submitted with their offers, and the Commission should carefully
6 review the different risk profiles of offered projects, including future market-related risks.

7 In consideration of a comprehensive and transparent analysis of the levelized cost
8 of electricity of resources competing in this procurement; the operational, efficiency, and
9 environmental benefits of combined cycle technology relative to competing alternatives;
10 and the value in shielding ratepayers from certain development, cost and operational
11 risks, I conclude that Calpine’s Mankato facility should be among the resources selected
12 in this acquisition process.

13 Q. **Does this conclude your testimony?**

14 A. Yes.

**Exhibit No. ____ (PJH-2)
Curriculum Vitae**

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EDUCATION

Ph.D. program (coursework), Nuclear Engineering, University of California, Berkeley

M.S. in Energy and Resources, University of California, Berkeley
Thesis: Safety and Environmental Hazards of Nuclear Reactor Designs

B.S. in Physics, University of Massachusetts, Amherst

PROFESSIONAL EXPERIENCE

2010 - Present Analysis Group, Inc., Boston, MA
Vice President

2007 - 2010 MA Department of Public Utilities, Boston, MA
Chairman
Member, Energy Facilities Siting Board
Manager, New England States Committee on Electricity
Treasurer, Executive Committee, Eastern Interconnect States' Planning Council
Representative, New England Governors' Conference Power Planning Committee
Member, NARUC Electricity Committee, Procurement Work Group

2003 - 2007 Analysis Group, Inc., Boston, MA
Vice President
Manager ('03 - '05)

2000 - 2003 Lexecon Inc., Cambridge, MA
Senior Consultant
Consultant ('00 - '02)

1998 - 2000 Massachusetts Department of Environmental Protection, Boston, MA
Environmental Analyst

1991 - 1998 Massachusetts Department of Public Utilities, Boston, MA
Senior Analyst, Electric Power Division

1988 - 1991 University of California, Berkeley, CA
Research Assistant, Safety/Environmental Factors in Nuclear Designs

OTHER PROFESSIONAL ACTIVITIES

Advisory Board, Advanced Energy Economy (2011).

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Testimony of Paul J. Hibbard before the New Hampshire Legislature, *RGGI and the Economy – Following the Dollars*, NH House Committee on Science, Technology, and Energy, February 14, 2012.

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Hibbard, Paul J. and Susan F. Tierney, *Carbon Control and the Economy: Economic Impacts of RGGI’s First Three Years*, The Electricity Journal, December 2011.

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“Carbon Regulation: Action and Convergence Spanning the Pond,” presentation to Energy Smart Conference, Boston MA, October 2010.

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“Energy Infrastructure Challenges in the Current Policy Environment, A Wide Angle Point of View,” presentation to NARUC, Providence RI, September 2010.

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“Renewables Development – National Policies, New England Progress,” presentation to National Association of State Energy Officials Annual Meeting, Boston MA, September 2010.

“Northeast US and Eastern Canada – Competitive Markets and Renewable Resource Development,” presentation to LSI Conference on US/Canada Energy Transactions, Vancouver BC, August 2010.

“Renewables in the Northeast – Local Opportunities, National Context,” presentation to Council of State Governments, Portland ME, August 2010.

“Deregulation and Sustainable Energy,” class lecture, MIT (Jonathan Raab Energy Course), Cambridge MA, March 2010.

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“Consumers and Politicians Claim They Want Cheap, Reliable and Clean Energy – Do They Have the Will to Make That Happen?” – presentation to NAESCO New England Regional Meeting, September 28, 2006.

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**Exhibit PJH-3 (page 1 of 2)
Base Case Assumption in Levelized Cost of Electricity Analysis**

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

**Exhibit PJH-3 (page 2 of 2)
Base Case Assumption in Levelized Cost of Electricity Analysis**

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

**Exhibit PJH-4
Levelized Cost of Electricity (\$/MWh)
Base Case and Sensitivities**

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]

**Exhibit PJH-5
Levelized Cost (\$/MWh) by Capacity Factor
Base Case Scenario**

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TRADE SECRET INFORMATION ENDS]

**Exhibit PJH-6a
Emission Rates by Technology:
Nitrous Oxide (NO_x)**

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TRADE SECRET INFORMATION ENDS]

**Exhibit PJH-6b
Emission Rates by Technology:
Carbon Dioxide (CO₂)**

[TRADE SECRET INFORMATION BEGINS

TRADE SECRET INFORMATION ENDS]