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**PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED**

September 11, 2015

- Via Email and Federal Express -

Darrell Nitschke, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept 408
600 East Boulevard
Bismarck, ND 59505-0480

RE: REBUTTAL TESTIMONY
NORTHERN STATES POWER COMPANY APPLICATION FOR ADVANCED
PRUDENCE – 345 KW MANKATO ENERGY CENTER
CASE NO. PU-15-96

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, respectfully submits an original and nine copies of our rebuttal testimony in the above-referenced case.

The following rebuttal testimony is being filed:

- *Christopher B. Clark* – providing rebuttal testimony on the Company's commitment to seeking a path forward that respects North Dakota's energy policy positions and rebuttal testimony on the Company's future capacity needs and the implications of denying this Application.
- *Kurtis J. Haeger* – providing rebuttal testimony on the value of the Mankato Energy Center Power Purchase Agreement (PPA) and the Company's resource planning processes.
- *Paul B. Johnson* – providing rebuttal testimony on forecast issues, capacity needs, capacity risks, and cost impacts of the proposed PPA,

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In addition, the Company is submitting in a sealed envelope marked **TRADE SECRET-PRIVATE** one copy of the trade secret version of the rebuttal testimony of Mr. Johnson.

The Company believes this information to be proprietary and of a privileged nature and we consider it to be Trade Secret. This information is consistent with the type of information described in the Company's pending February 13, 2015 Application for Trade Secret Protection. Any rebuttal testimony containing trade secret information is marked **NON-PUBLIC** consistent with our Trade Secret Application dated February 13, 2015.

Please contact me if you have any questions regarding this filing.

Sincerely,

A handwritten signature in blue ink that reads "David H. Sederquist". The signature is written in a cursive style.

DAVID H. SEDERQUIST
Sr. Consultant, Regulation & Finance
Enclosures

cc: attached list

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Rebuttal Testimony
Christopher B. Clark

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company's
Advance Determination of Prudence for its 345 MW Power Purchase Agreement
with Mankato Energy Center, LLC

Case No. PU-15-96
Exhibit____(CBC-1)

Rebuttal of Advocacy Staff (Polich) Testimony

September 11, 2015

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is Christopher B. Clark. I am the President of Northern States
5 Power Company – Minnesota (Xcel Energy or the Company).

6
7 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

8 A. I have over 20 years of experience in energy and regulation. I joined the
9 Company in 1999 as a Senior Attorney and then served as a Managing
10 Attorney for the Company. In that role, I was responsible for the Company’s
11 state public utility law and power purchase agreement issues for its operations
12 in North Dakota, South Dakota, Minnesota and Wisconsin. After that I had
13 the role of Vice President, Regulatory in which I was responsible for
14 regulatory matters for the Company in the states of North Dakota, South
15 Dakota and Minnesota.

16
17 In December 2014 I was appointed to the position of President of the
18 Company. In my current role, I am accountable for the overall planning and
19 performance of the Company, with direct oversight of the customer,
20 community, regulatory, and legislative areas.

21
22 Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

23 A. I have two purposes for my Rebuttal Testimony.

24
25 First, Ms. Laura McCarten is a Regional Vice President of the Company and
26 one of my direct reports. She submitted Direct Testimony in this matter. I
27 am adopting that testimony and I provide this Rebuttal Testimony to

1 underscore the Company's and my commitment to seeking a path forward
2 that respects North Dakota energy policy and that provides the best overall
3 value to the customers we serve in North Dakota and across the NSP
4 integrated system. I will be available to answer any questions Commissioners
5 or Staff may have arising out of this matter.

6
7 Second, my Rebuttal Testimony responds to the testimony of Advocacy Staff
8 witness Mr. Richard D. Polich. I respond to Mr. Polich's conclusion that the
9 Company has sufficient capacity to serve our customers through 2024 and his
10 opinions about whether the Power Purchase Agreement for the Mankato
11 Energy Center natural-gas, combined-cycle expansion project (Mankato PPA)
12 commencing in 2019 is a prudent resource addition under the circumstances.
13 Company witnesses Mr. Kurt Haeger and Mr. Paul B. Johnson provide
14 additional analysis and testimony and respond to some of the specific issues
15 raised in Mr. Polich's testimony.

16
17 Finally, I am concerned about the implications of denial of this ADP request.
18 If our North Dakota customers do not participate in the Mankato PPA, the
19 feasibility of continuing integrated system planning will be challenged and
20 could lead to consequences we haven't determined how to address. I do not
21 believe that this is in the best interests of our North Dakota customers or the
22 Company. Mr. Haeger's Rebuttal Testimony provides additional context on
23 those concerns. But from my perspective, I recommend that the Commission
24 accept the Mankato PPA as an important part of the Company's long-term
25 plans that will provide good value to our North Dakota customers.

26
27 Q. WHY IS THE PRESIDENT OF THE UTILITY TESTIFYING IN THIS MATTER?

1 A. I am testifying in support of the Company's request for an Advance
2 Determination of Prudence (ADP) for several reasons. First, and most
3 important, I am here because I want to reinforce the Company's commitment
4 to foster and maintain positive relationships with the Commission and
5 stakeholders in North Dakota.

6
7 We operate a five-state integrated system, and maintaining positive
8 relationships with stakeholders throughout our system is important. Through
9 this testimony, I want to underscore the importance of the Company's
10 relationship with our North Dakota customers, this Commission and other
11 stakeholders in this State.

12
13 Second, as the Commission is aware, we must take into account the energy
14 policies and preferences of each State served by our integrated system and we
15 must seek a balance that respects the States' policies and that also allows us to
16 continue to provide adequate and reliable service to all customers we serve.
17 Overall, the Company has been successful at this and has been able to bring
18 good value to our customers in North Dakota and elsewhere. However, in
19 recent years, we have experienced increasing challenges in achieving this
20 balance as States energy policies have increasingly diverged.

21
22 Q. WHAT IS YOUR PERSPECTIVE ON THE CHOICES THAT ARE AVAILABLE TO THE
23 COMMISSION IN THIS CASE?

24 A. I appreciate that the Commission faces difficult legal and energy policy issues
25 presented by the changing utility landscape, including the evolution of the
26 Company's generation portfolio over the next several decades and recent
27 federal environmental initiatives. While I recognize that some of those federal

1 initiatives are not final, may be revised, and may be challenged, it is clear that
2 the utility landscape is changing. The Company is mindful of this landscape
3 and strongly believes that our customers will be best served if we pursue
4 prudent options when planning for this uncertain future.

5
6 This case is integral to addressing the evolving utility landscape as well as the
7 future of the Company's existing resource portfolio.

8
9 Q. DO YOU AGREE WITH MR. POLICH'S CONCLUSION THAT THE COMMISSION
10 SHOULD REJECT THE COMPANY'S REQUEST FOR AN ADP FOR THE MANKATO
11 PPA?

12 A. No. While I appreciate Mr. Polich's analysis and believe it provides the
13 Commission with a valuable perspective, I do not reach the same conclusion.
14 When factoring in all of the relevant circumstances, the Mankato PPA is an
15 important resource addition that can cost-effectively serve our customers'
16 long-term needs and that will prepare the NSP system for the future.

17
18 **II. RESPONSE TO "NEED" CONCLUSION**

19
20 Q. MR. POLICH CONCLUDES THAT NSP DOES NOT NEED TO ADD ANY
21 GENERATION RESOURCES PRIOR TO 2025 (P. 7, LINE 9-10, P. 17, LINE 22, P. 26,
22 LINE 5). HOW DO YOU RESPOND?

23 A. Company witnesses Mr. Haeger and Mr. Johnson address specific aspects of
24 Mr. Polich's analysis. I will focus on the fundamental question of "need" and
25 how the combination of circumstances show the Mankato PPA to be a
26 prudent resource choice. Mr. Polich's analysis does not give adequate weight
27 to other important factors that I will discuss later in my Testimony.

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Q. DO YOU DISAGREE WITH MR. POLICH’S OPINION THAT THE COMPANY DOES NOT NEED THIS CAPACITY BEGINNING IN 2019?

A. I recognize that the basis for Mr. Polich’s opinion is tied to traditional resource planning concepts of matching load forecasts with capacity additions. However, the question of need is broader and more complex than just assessing the load and capability levels without accounting for other considerations and variables. When those other considerations and variables are factored in, the Mankato PPA commencing in 2019 is a prudent purchase. I detail these additional considerations later in my testimony. In summary, the totality of the pricing, flexibility, and optionality offered by the Mankato PPA outweigh the timing concerns addressed by Mr. Polich.

III. SELECTION OF MANKATO PPA

Q. PLEASE SUMMARIZE THE CIRCUMSTANCES UNDER WHICH THE COMPANY CHOSE TO PURSUE THE MANKATO PPA.

A. In our prior 2010 resource plan (Case No. PU-10-0989), the Company identified a need for up to 500 MW of incremental capacity by 2019 based on the Company’s 2011 forecast. Based on this identified need, the Company determined that it would be prudent to add capacity to its system. I note that it was this same identified need that led us to propose the addition of a new combustion turbine at our existing Black Dog facility, for which the Commission granted an ADP.

In light of this identified need, the Company undertook a competitive process to fill that capacity need. This “Competitive Acquisition Process” is

1 commonly referred to as the “CAP/CON” Proceeding (MPUC Docket No.
2 E-002/CN-12-1240). As part of the CAP/CON Proceeding, the Company
3 obtained approval for capacity additions to meet the identified need of up to
4 500 MW of capacity by 2019 consistent with our 2010 Resource Plan. The
5 Mankato PPA was bid into this CAP/CON Proceeding and was selected as a
6 least cost resource through this process to meet our up to 500 MW of need.
7 Then, ultimately, the Company entered into the Mankato PPA and is now
8 seeking an ADP from the Commission.

9
10 Q. DID THE COMPANY OPPOSE SELECTING THE MANKATO PPA AS A NEW
11 CAPACITY RESOURCE IN THE CAP/CON PROCEEDING?

12 A. In general the Company took the position that, while the Mankato PPA was
13 reasonably priced, it was not needed in the 2017-19 timeframe. The Company
14 went on to suggest that due to uncertainty of an aging fleet, that the MPUC
15 keep the bids under review open and provide more time to evaluate data and
16 cost changes associated with delaying the in-service dates of the proposed
17 projects. More specifically, the Company proposed to have the Mankato PPA
18 and Black Dog prices updated to reflect a 2019 in-service date with the
19 flexibility for further delay.

20
21 Q. WHAT DID THE MPUC DECIDE?

22 A. While the MPUC recognized the variation in forecasts and the changing
23 dynamics of the resource planning process, the MPUC ultimately decided to
24 take a conservative approach to the underlying need analysis and rely on the
25 2011 forecast showing that the Company needed up to 500 MW of
26 incremental new capacity by 2019. The MPUC did agree with the Company
27 that a conservative approach to resource planning is appropriate and adopted

1 the view that it is prudent to be long on capacity rather than potentially falling
2 short.

3
4 Through the CAP/CON Proceeding, the MPUC selected both the Mankato
5 PPA and Black Dog Unit 6 as least-cost, prudent resources to fill the up-to
6 500 MW of identified capacity need. The MPUC also selected the Aurora
7 Solar Project that was the subject of Case No. PU-15-95.

8
9 Q. IS THE COMPANY'S POSITION DIFFERENT NOW IN THIS PROCEEDING IN
10 COMPARISON TO WHAT IT WAS IN THE CAP/CON PROCEEDING?

11 A. In the CAP/CON Proceeding we asked for pricing for a 2019 in-service date,
12 and pricing that would reflect a delay of that in-service date. Consistent with a
13 conservative view toward resource planning, the Mankato PPA has been
14 delayed to 2019. We are not currently anticipating further delay at this time.

15
16 Over the last year the landscape in which we are operating has continued to
17 evolve with several issues coming to the forefront. In August, the EPA issued
18 their final Clean Power Plan rule, our 2015 Resource Plan process is
19 underway, and the Company has begun to evaluate its aging fleet. These
20 changes to the industry have highlighted the uncertainty attendant in making
21 resource additions during a time of evolving usage and environmental
22 requirements. Major resource additions are long-lead-time investments that
23 require several years to plan, permit and implement. This heightens the
24 uncertainty as conditions continue to evolve during the planning and
25 permitting stages.

26

1 Because factors affecting need are continually changing, resource decisions
2 must necessarily be made in the midst of flux and the decision whether or not
3 to pursue a particular resource must be made based on the totality of all of the
4 circumstances. While it is possible to abandon a project in the face of
5 changing forecasts, that is not a step that should be taken lightly as it could
6 require starting over if circumstances shift or the forecast rebounds
7 unexpectedly.

8
9 In this instance, it really boils down to what criteria are to be applied to the
10 decision to pursue the Mankato PPA. In the CAP/CON Proceeding, the
11 Company focused on many of the same types of resource planning criteria
12 relied upon by Mr. Polich, with an eye, however, toward the evolving utility
13 landscape. Similar to Mr. Polich, the Company thought it was appropriate to
14 rely on updated forecasts and, focusing on narrow load and capacity
15 considerations, concluded that customers could be served adequately with
16 other resources. However, we also recognized that other factors could justify
17 a different decision and we accepted that reasonable minds could differ on the
18 question of whether to pursue the Mankato PPA in addition to Black Dog
19 Unit 6.

20
21 Q. HOW HAS THE COMPANY'S VIEW OF THE MANKATO PPA CHANGED SINCE THE
22 CAP/CON PROCEEDING?

23 A. Since the selection of this resource in the CAP/CON Proceeding, we have
24 integrated the Mankato PPA into our resource planning efforts and we have
25 internalized the benefits and costs of this resource. We have concluded that
26 this is an important resource for our long-term plans and that when all
27 relevant factors are considered, this is a prudent investment. Obtaining

1 combined-cycle capacity at favorable pricing provides us with flexibility to
2 address the evolving utility landscape and, although the timing is imperfect,
3 the deal presented by the Mankato PPA is a good resource addition to our
4 system that we should not pass up. While we appreciate Mr. Polich’s resource
5 planning analysis, we conclude that other factors override his conclusions on
6 the need for this resource.

7
8 This proceeding is an important opportunity for us to obtain the input of the
9 Commission as we make our decision about this resource. We believe that the
10 resource addition is prudent and hope the Commission will agree. However,
11 in light of the procedural schedule of this case, we have amended the Mankato
12 PPA to extend our ability to cancel the contract until March 31, 2016 should
13 the Commission not grant us the requested ADP.

14
15 **IV. DISCUSSION OF CRITERIA**

16
17 Q. WHAT FACTORS DOES MR. POLICH FOCUS ON IN HIS ANALYSIS?

18 A. Mr. Polich focuses primarily on standard planning principles and criteria.
19 Based on those criteria, I must point out that Mr. Polich does not disagree
20 with the overall system value of the Mankato PPA.

21
22 I note that he acknowledges (p. 10, Line 9-13) that “[o]ther factors, such as
23 changes in Midwest ISO (“MISO”) rules, government regulation such as the
24 Clean Power Plan, state regulatory agency rejection of resources additions, and
25 market factors such as the declining cost of solar energy, need to be factored
26 into” the decision whether and when to add resources. I agree with his
27 observation that other criteria need to be factored into the analysis.

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Q. PLEASE EXPLAIN THE FACTORS THAT THE COMMISSION SHOULD INCLUDE IN ITS CONSIDERATION OF THIS MATTER.

A. There are several considerations that make purchasing the capacity and energy under the Mankato PPA a prudent investment. They are: (i) advantageous pricing that is available beginning in 2019; (ii) optionality that the Mankato PPA provides for the Company to optimize its system; and (iii) flexibility to have combined-cycle capacity and energy available before 2020 to help bridge potential tight capacity MISO-wide due to anticipated coal plant shutdowns that are projected in the next decade as well as to address evolving environmental requirements.

Q. DOES MR. POLICH’S TESTIMONY ACCOUNT FOR THESE VARIABLES?

A. It does not appear that he did. While he mentions the “Clean Power Plan” on page 10, Line 10-11, he does not explicitly factor this into his assessment. His testimony does not address the pricing, efficiencies or flexibility afforded by the Mankato PPA.

1. Advantageous Pricing

Q. PLEASE DESCRIBE THE ADVANTAGEOUS PRICING UNDER THE MANKATO PPA.

A. The pricing for the capacity under the Mankato PPA is favorable. By taking advantage of a developed site and adding a second unit using largely existing infrastructure, Calpine was able to offer competitive pricing.

1 Q. IS COMBINED-CYCLE CAPACITY BETTER THAN COMBUSTION TURBINE
2 CAPACITY?

3 A. It depends upon the purpose of the resource addition and the pricing of the
4 proposals.

5
6 Generally combustion turbine capacity is cheaper. Thus, if the only need
7 identified is for capacity (with low energy production) a combustion turbine
8 might be the appropriate choice. Combustion turbines are less efficient to
9 operate, though, and therefore each unit of energy they produce is
10 comparatively more expensive than other types of generation resources.
11 Because of this, combustion turbines typically operate around five percent of
12 the hours of the year.

13
14 On the other hand, combined-cycle plants can be operated efficiently, making
15 each unit of energy cheaper to produce than that of a combustion turbine.
16 Therefore, combined cycle plants are available to operate 30-50 percent or
17 more of the time to serve energy needs. However, to obtain this more
18 efficient operation, combined cycle plants are generally more expensive to
19 build on a per-kW of capacity basis.

20
21 Q. WHY IS THIS IMPORTANT IN EVALUATING THE PRUDENCE OF THE MANKATO
22 PPA?

23 A. The Mankato PPA gives us the best of both worlds with efficient, and
24 cheaper, combined-cycle energy production at pricing competitive with
25 combustion turbines. In light of this, and the potential for the retirement of
26 baseload plants (which combined cycle generation is expected to replace due
27 to evolving federal environmental regulatory requirements) throughout the

1 region in the near future, it is prudent to capture this efficient generation
2 resource at bargain pricing now, while it remains available.

3
4 Q. COULD YOU HAVE DEFERRED THE MANKATO PPA FOR AN ADDITIONAL SIX
5 YEARS UNTIL 2025 TO ADDRESS MR. POLICH'S CONCLUSION THAT THE
6 CAPACITY IS NOT NEEDED IN 2019?

7 A. I do not believe so. Calpine bid this project as part of the competitive bidding
8 required by the CAP/CON and made it available to us only for potential 2018
9 or 2019 in-service dates. This pricing would likely not be available for an
10 equivalent combined-cycle plant in 2025.

11
12 Q. HOW CAN CALPINE MAKE THIS PRICING AVAILABLE?

13 A. At base, the Mankato PPA is an expansion of an existing power plant. When
14 the original Mankato Energy Center was built more than 10 years ago, it was
15 designed with the potential for expansion already in mind. Common facilities
16 were designed to accommodate the expansion efficiently, natural gas pipeline
17 facilities were sized to support higher flows, and the need for additional
18 electric transmission capacity was foreshadowed. All of this put Calpine in a
19 position to offer the expansion proposal to Xcel Energy or another utility in
20 the 2017-19 timeframe.

21
22 Additionally, because Calpine was required to bid this project into the
23 CAP/CON, the competitive bidding nature of the CAP/CON process
24 mandated that Calpine provide its best bid to be evaluated. This allowed us to
25 have confidence that we were receiving good pricing for this resource
26 addition.

27

1 Q. WOULD THOSE SAME INFRASTRUCTURE BENEFITS HAVE BEEN AVAILABLE TO
2 XCEL ENERGY HAD YOU WAITED TO PROCURE THE MANKATO PPA FOR 2025
3 CONSISTENT WITH MR. POLICH'S OPINION OF THE TIMING OF THE COMPANY'S
4 NEED?

5 A. We cannot count on that capacity being available to us another six years out.
6 Also, we could not assume that we would be able to procure that capacity at
7 comparable pricing. Waiting an additional six years to lock in this capacity
8 would have left us at the risk of market forces and the risk that Calpine would
9 sell the expansion capacity to someone else.

10

11 Q. WHAT MARKET FORCES ARE YOU CONCERNED ABOUT?

12 A. I am concerned the cost of combined-cycle capacity will increase substantially
13 over the next decade due to a substantial increase in demand for combined-
14 cycle plants in line with the evolving utility landscape. Mr. Johnson provides
15 some context for this concern.

16

17 Q. WHAT IS YOUR CONCERN THAT CALPINE MIGHT HAVE SOLD THE MANKATO
18 EXPANSION PROJECT TO SOMEONE ELSE?

19 A. We did not have exclusive rights to the expansion capacity, nor did we control
20 Calpine's ability to market the project to others in the region who may also
21 need advantageously-priced capacity.

22

23 I note that other utilities also have capacity needs in the 2020 timeframe and it
24 is certainly possible that Calpine could sell the Mankato expansion capacity to
25 someone else if we do not buy it in the timeframe offered. Because of the
26 advantageous pricing, we concluded it was better for Xcel Energy to take the
27 capacity in 2019.

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2. *Optionality*

Q. PLEASE DESCRIBE THE OPTIONALITY BENEFITS THAT YOU MENTIONED.

A. As Mr. Polich points out (p. 17, Line 12-17), the Company has plans to retire some of our oldest and least-efficient peakers in the 2024 timeframe. Adding the Mankato PPA to the system in 2019 allows us optionality to consider accelerating those retirements, which will allow us to optimize our system. Mr. Johnson’s Rebuttal Testimony provides some analysis showing that, with the addition of the capacity associated with the Mankato PPA, we could shut down our older peakers earlier than Mr. Polich assumes.

Q. WHY WOULD IT BE BENEFICIAL FOR CUSTOMERS TO ACCELERATE THE RETIREMENT OF THESE UNITS?

A. We would be able to better optimize our system by replacing older generators that have reached the end of their useful life with new and advantageously-priced capacity.

Q. WHAT OTHER OPTIONALITY BENEFITS WOULD ARISE FROM DEPLOYING THE MANKATO PPA IN 2019?

A. The nature of our system is changing. Our resource plan covers the period to 2030 and in that timeframe we see the potential for significant changes in our generation portfolio. Some of our older coal plants will likely be retired in the planning horizon absent major upgrades. Our PPA with Manitoba Hydro expires in 2025. The operating licenses for our nuclear units expire in the early 2030s, just after the current planning horizon. Further, the generation mix in the MISO footprint is changing as older coal plants retire. All of these factors suggest that having additional combined-cycle capacity available to

1 serve our customers is appropriate, particularly in light of the advantageous
2 price of the Mankato PPA.

3
4 Q. IF THE COMPANY IS LONG ON CAPACITY FROM 2019 THROUGH 2024 AS
5 SUGGESTED BY MR. POLICH, WOULD THAT CAPACITY BE WASTED?

6 A. No. In addition for potential to optimize our system, the Company could also
7 make the length in our system available to other utilities through the market.
8 The Company shares the margins it receives from capacity sales with our
9 customers, thereby creating value for customers in that scenario.

10
11 *3. Flexibility*

12 Q. WHAT ARE THE FLEXIBILITY CONSIDERATIONS THAT SHOULD BE TAKEN INTO
13 ACCOUNT?

14 A. There are several, but they all relate to the advantages of having combined-
15 cycle capacity available on the system to adapt to a variety of evolving
16 circumstances.

17
18 Q. WHAT ARE THE ENVIRONMENTAL CONSIDERATIONS THAT SUPPORT
19 DEPLOYING THE MANKATO PPA IN 2019?

20 A. The electric utility industry is in a period of significant uncertainty in light of
21 tightening environmental regulations. Tightening mercury emissions
22 requirements and likely CO₂ regulation under the Clean Power Plan as well as
23 other environmental initiatives all point to the need to adapt and be flexible
24 with our resource portfolio. Having a significant increment of combined-cycle
25 capacity on our system facilitates that flexibility.

26

1 Q. HOW DOES THE MANKATO PPA FIT INTO THE COMPANY'S ENVIRONMENTAL
2 COMPLIANCE PLAN?

3 A. The Mankato PPA facilitates regional planning and provides us with flexibility
4 to respond to these evolving environmental regulations. Having additional
5 combined-cycle generation available in the 2019 timeframe will likely mitigate
6 the potential negative impacts to our customers of projected coal plant
7 shutdowns in the MISO region.

8

9 Recent federal environmental actions create conditions that will likely result in
10 a significant number of near-term coal plant retirements. Best Available
11 Control Technology (BACT) and other limitations make it increasingly
12 difficult for older coal plants to keep operating. Combined-cycle natural gas
13 generation is the only reasonable fossil-fuel alternative to retiring coal plants.
14 The recent Supreme Court ruling on the Mercury and Air Toxic Standards
15 (MATS) rule, and EPA's recent announcement of the Clean Power Plan
16 simply add to that uncertainty and put further pressure on existing coal
17 generation.

18

19 These emerging requirements and the pressure to retire coal plants will
20 increase competition and pricing for replacement combined-cycle units. As a
21 result, we could not assume that the Mankato PPA pricing would remain
22 available to us for later deployment.

23

24 Q. DOES XCEL ENERGY HAVE ANY COAL PLANTS THAT MAY BE RETIRED IN THE
25 NEXT DECADE?

26 A. Yes. The potential retirement of one or two units at our Sherco facility has
27 been discussed at great length in our pending resource plan (Case No. PU-15-

1 19) and elsewhere. We will be filing an update of our resource plan proposal
2 on October 2 and that update will be available for consideration in this case.

3
4 While no decisions have been made at this time, we continue to evaluate a
5 decision to retire either Sherco Unit 1 or Sherco Unit 2 or both of them
6 before 2025. Each of those Sherco units is approximately 750 MW. Some
7 stakeholders have proposed shutting down one of those units as early as 2021.
8 If that were to happen, the Mankato PPA provides significant replacement
9 capacity as well as efficient combined-cycle energy (as opposed to expensive
10 combustion turbine energy) to address any potential capacity shortfall.

11 **V. BENEFITS OUTWEIGH TIMING CONCERNS**

12
13
14 Q. HOW DO YOU RESPOND TO MR. POLICH'S CONCLUSION (P. 17, LINE 22-P. 8
15 LINE 1) THAT "NSP SHOULD NOT INCREASE GENERATION CAPACITY UNTIL
16 2025. IT WOULD NOT BE PRUDENT TO ADD CAPACITY THROUGH A 20-YEAR
17 PPA STARTING IN 2019 BECAUSE 30% OF THE PPA CONTRACT PERIOD WILL
18 HAVE EXPIRED PRIOR TO THE ANTICIPATED NEED FOR THE CAPACITY."?

19 A. I acknowledge that the timing of the Mankato PPA is not ideal. However, Mr.
20 Polich's analysis does not consider the factors I described above. Under the
21 totality of the circumstances, it is better to accept the Mankato PPA beginning
22 in 2019. Not accepting the Mankato PPA will create significant uncertainties
23 for the integrated system and would forego capturing the benefits that I have
24 outlined. Mr. Haeger's Rebuttal Testimony provides additional discussion of
25 the uncertainties that would occur if the Mankato PPA is rejected.

26

1 Q. WOULD IT BE BETTER TO WAIT UNTIL THE CUSTOMER DEMAND DEVELOPS TO
2 ADD NEW GENERATION?

3 A. Under the circumstances we were presented with, no. First, we were
4 presented with the Mankato PPA in response to an RFP for generation
5 resources in the 2017-19 timeframe that we initiated due to our own resource
6 planning efforts in the 2010-2011 time frame. This was the Company's good-
7 faith effort to respond to an identified need shown in our 2011 forecast.
8 While the Company acknowledges that updated forecasts suggested that our
9 capacity need might be somewhat less than the initial projection, we always
10 recognized that new capacity on the system was appropriate, particularly when
11 all of the other factors are considered. At the advantageous pricing offered,
12 we conclude that it is more appropriate to accept the earlier in-service
13 obligation than to wait to undertake a more expensive project in 2024.

14
15 Second, we do not agree with Mr. Polich that it would be better to wait under
16 the circumstances. Planning and implementing new generation takes several
17 years. In the case of a combined-cycle plant, six to eight years are needed to
18 fully plan for and permit such a plant. A lot can happen during that planning
19 period. The demand forecast could rebound; coal plant retirements could
20 create a near-term need for additional capacity; and other market and
21 environmental factors could drive up the cost. Additionally, the advantageous
22 pricing that can only be obtained from the Mankato PPA may not be available
23 requiring us to choose between cheaper combustion turbine capacity and the
24 resultant more expensive energy or more expensive combined cycle capacity
25 and the resultant cheaper energy. From all of this, the Company believes it is
26 prudent for us to move forward with a combined-cycle plant at this time in
27 order to meet the projected timelines.

1
2 Third, Xcel Energy is the largest utility in North Dakota with an obligation to
3 provide reliable service. I take this obligation seriously. To ensure that the
4 Company never finds itself in a shortfall position, we plan our integrated
5 system to ensure sufficient capacity to satisfy our customers' needs in all
6 reasonable circumstances. Thus, when an advantageously-priced combined-
7 cycle proposal such as the Mankato PPA is presented, we must evaluate the
8 overall value of that proposal despite the timing to ensure that it is, overall, in
9 the best interests of our customers.

10
11 As shown by Mr. Johnson's analysis, if we retire our older and inefficient
12 peakers in the 2019-20 timeframe (which can happen only if we have the
13 Mankato PPA available to us) our system is only long by no more than 450
14 MW beyond the minimum MISO required reserves during the 2019-24
15 timeframe, or only about four to five percent. While that is somewhat more
16 than the minimum requirements set by MISO, it is a relatively small amount
17 compared to our 10,000 MW system and is a prudent "cushion" to maintain
18 above our reserve margin obligations. Mr. Haeger discusses this issue in
19 greater detail. Further, having a modest amount of additional capacity
20 available gives us the flexibility to bridge other utilities' capacity needs.

21
22 Q. DOES THE COMPANY CONCLUDE THAT THE MANKATO PPA IS IN THE BEST
23 INTERESTS OF CUSTOMERS OVERALL?

24 A. Yes. We conclude that accepting the Mankato PPA in 2019 is more
25 advantageous to our customers than waiting for an alternative proposal in the
26 2024-25 timeframe. Mr. Johnson's Rebuttal Testimony provides the
27 Company's analysis on why the economics of this proposal made sense.

1

2

VI. CONCLUSION AND SUMMARY

3

4 Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

5 A. I recommend that the Commission approve the ADP for the Mankato PPA.

6 While we accept that this PPA represents capacity that could be deferred

7 under some circumstances (as identified by Mr. Polich's testimony), on

8 balance we believe that approving the Mankato PPA is in our customers'

9 interest overall.

10

11 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

12 A. Yes, it does.

Rebuttal Testimony
Kurtis J. Haeger

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company's
Advance Determination of Prudence for its 345 MW Power Purchase Agreement
with Mankato Energy Center, LLC

Case No. PU-15-96
Exhibit___(KJH-2)

Rebuttal of Advocacy Staff (Polich) Testimony

September 11, 2015

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1 **I. INTRODUCTION AND SUMMARY**

2
3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Kurtis J. Haeger. I am the Area Vice President of Resource
5 Planning for Xcel Energy Services Inc. (XES), the service company subsidiary of
6 Xcel Energy Inc. In that role I coordinate the resource planning function for
7 Northern States Power Company-Minnesota (NSP, Xcel Energy or the
8 Company).

9
10 Q. HAVE YOU PROVIDED OTHER TESTIMONY IN THIS CASE?

11 A. Yes. I submitted prefiled written Direct Testimony in this proceeding (Exhibit
12 ____ (KJH-1)). That testimony provided the Commission with the Company's
13 view of the resource planning context that supports granting an Advance
14 Determination of Prudence (ADP) for the Power Purchase Agreement (PPA)
15 with Calpine for the expansion project at the Mankato Energy Center (the
16 Mankato PPA).

17
18 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

19 A. I respond to the Direct Testimony of Commission Advocacy Staff witness Mr.
20 Richard A. Polich. I also address the value of the Mankato PPA to the overall
21 NSP System as well as the challenges inherent in operating a multi-state system
22 in light of divergent energy policies and the impact that this proceeding could
23 have on these challenges.

24
25 While Mr. Polich provides a helpful review of the resource planning
26 considerations, I am concerned that his analysis does not address the full set of
27 circumstances the Commission should take into account when it considers

1 whether to grant the requested ADP. Additionally, I address my concerns with
2 respect to the accuracy of his analysis and important real world resource
3 planning considerations that go beyond Mr. Polich's analysis.

4
5 More specifically, Mr. Polich's testimony does not fully take into account the
6 reasonable need to preserve some system length to address the very real
7 variability of the numerous components of our load and resource calculations.
8 Such variables include, evolving reserve margin requirements, changing
9 coincident or non-coincident peaks, changing economic conditions, and the
10 impact of the reliability of plant operations on our capacity accreditation. Mr.
11 Polich also incorrectly concludes that the impact of adding the Mankato PPA to
12 the system will be greater than the total cost the Company will pay to Calpine for
13 the years in question. Mr. Johnson explains in greater detail the error that Mr.
14 Polich makes in his testimony relative to the cost impacts of the Calpine PPA.
15 As a result, Mr. Polich's recommendation does not fully take into account all of
16 the considerations that support the prudence of the Company's decision to
17 pursue the Mankato PPA.

18
19 Last, Mr. Polich's recommendation carries with it certain implications and risks
20 that should also be taken into account as the Commission is contemplating the
21 requested ADP.

22
23 Q. HOW IS YOUR REBUTTAL TESTIMONY STRUCTURED?

24 A. My Rebuttal Testimony provides the Company's perspective on the issues raised
25 by Mr. Polich and our analysis of the implications of his recommendation. More
26 specifically, I address the following:

- 27
- The complexity of the Company's resource planning efforts, its underlying

1 principles and the importance of this resource to our overall system;

- 2 • The value of the Mankato PPA to our overall system; and
- 3 • The difficulties in operating a multi-state integrated system in the face of
- 4 divergent state energy policies and the challenges to that system should
- 5 the Commission choose to deny the requested ADP.
- 6 • Finally, I provide a brief update on the status of the ongoing Restack
- 7 negotiations with Staff.

8

9 **II. RESOURCE PLANNING ANALYSIS**

10

11 Q. MR. POLICH CONCLUDES THAT THE MANKATO PPA IS NOT NEEDED PRIOR TO

12 2025 BASED ON HIS ASSESSMENT OF THE COMPANY'S LOAD AND RESOURCE

13 CHARTS. HOW DO YOU RESPOND?

14 A. I generally accept the legitimacy of Mr. Polich's high level analysis and agree that

15 standard resource planning methodologies are an important analytical construct

16 for assessing the selection and timing of new generation resources. However, it

17 is my view that Mr. Polich tends to ignore the potential variability of key

18 resource planning inputs when reaching his conclusion that the Company has

19 adequate generation resources through 2024.

20

21 In performing his analysis, Mr. Polich appears to have relied upon only the

22 Company's Loads and Resources tables. While these high level summaries of

23 Load Obligation, Reserve Margin, Existing Resources, and Net Positions provide

24 a quick view into the Company's generation portfolio, they do not tell the full

25 story. As a result, I do not agree with Mr. Polich's conclusions. Rather, given the

26 excellent pricing for this resource addition and the flexibility and optionality it

27 provides for the Company, I conclude that the Mankato PPA is a prudent

1 purchase beginning in 2019.

2
3 Q. PLEASE SUMMARIZE HOW MR. POLICH'S ANALYSIS FALLS SHORT OF THE FULL
4 ANALYSIS THAT YOU THINK IS CRITICAL TO CONSIDER WHEN SELECTING NEW
5 GENERATION RESOURCES ?

6 A. The resource planning principles Mr. Polich considered are valid, but are not the
7 only criteria that should be considered in deciding whether the resource addition
8 is prudent. Not only should the Company consider the projected Net Position
9 of the Company's generation portfolio (whether it is long or short), but one
10 should take into account a whole host of additional factors including:

11
12 1) The history and variability around key resource planning variables:

- 13 a. Energy and demand forecasts;
- 14 b. Reserve margin and methodology;
- 15 c. Reliability criteria (coincident or non-coincident peak methodologies);
- 16 d. Generation accreditation values and methodologies;
- 17 e. Viability of on-going programs (load management);

18 2) The age of the existing fleet and key risks to the end of life of those assets;

19 3) The price of the resource;

20 4) The availability of alternative resources in the market;

21 5) Construction timing and availability of key generation components;

22 6) Transmission availability and timing;

23 7) Availability of fuel supply (natural gas);

24 8) Potential future environmental regulation; and

25 9) Contingency planning and the optionality that a resource can provide.

26
27 All of these factors need to be addressed when considering the need and cost of

1 adding a new generation resource, especially in periods of high uncertainty.

2
3 Q. DO YOU CONSIDER THIS A PERIOD OF GREAT OR HIGH UNCERTAINTY?

4 A. Yes. As demonstrated by Mr. Polich, the values for load obligation, reserve
5 margin, coincident/non-coincident peak factor, existing accredited capacity
6 having been moving significantly year by year. Through no fault of the
7 Company, the key variables in determining the forecast for overall net position
8 of the generation portfolio have been moving continuously throughout the last
9 five years. While the Company has continued to keep up with these changes,
10 and present updated summaries to the Commission, the fact remains that there
11 has been and will likely continue to be changes to these key variables.

12
13 Q. PLEASE PROVIDE A LITTLE MORE DETAIL ON THE ISSUES ASSOCIATED WITH
14 THESE KEY VARIABLES?

15 A. Key variables that we must take into account as we determine our load and
16 resource capabilities are:

17
18 1) *Energy and demand forecasts* – these forecasts are driven primarily by existing sale
19 trends and a forecast of future economic conditions. As the historical trends
20 begin to change and the forecast of future economic activity change, the
21 Company’s forecast for future energy and demand will also change. Since the
22 great recession of 2008, the forecasting of demand and energy sales has also
23 been impacted by increased energy efficiency of a number of electronic
24 products and a changing demographic. That said, we recognize that our most
25 recent four years of data (from our 2010 Resource Plan until our 2015
26 Resource Plan) indicate a slackening of customer demand in the NSP System.
27 However, the volatility in demand forecasts we experienced indicate a need to

1 preserve some system length should economic conditions suddenly change.
2 In fact, North Dakota has experienced these types of swings with the boom
3 and bust cycle in the oil and gas producing regions of the State.
4 Consequently, these factors have made forecasting rather difficult, with the
5 expectation that these uncertainties will continue into the near future.

6
7 2) *Reserve margin and methodology* – MISO has been significantly changing the
8 methodology for calculating the reserve margins. While MISO has indicated
9 that they are trying to provide a little more long-term stability in their reserve
10 margin numbers, there is concern that the changing make-up of the
11 generation fleet within MISO – due to the retirement of coal plants and the
12 addition of much more wind and solar – we believe that MISO’s reserve
13 margin and other planning requirements will be in a continuing state of flux
14 while the evolution of the generation mix continues to occur. While NSP is
15 becoming more comfortable with the reserve margin ranges MISO is using
16 over the past few years, we still do not have a great deal of history with the
17 new MISO process. Again, this argues for maintaining some reasonable
18 amount of length on the system to absorb any changes to MISO’s
19 requirements as they may arise.

20
21 3) *Reliability criteria (coincident or non-coincident peak methodologies)* – In 2013 MISO
22 implemented a methodology change that allowed NSP to measure its peak
23 demand requirements based on the timing of the peak of the entire MISO
24 system (non-coincident peak factor). This process of establishing the
25 reduction in the NSP peak demand (currently 5% reduction) is a process that
26 is conducted annually and is subject to change from year to year. After just a
27 couple of years of experience with this new methodology, we are still

1 evaluating the stability of the annual process. Again, should the NSP System
2 peak change in relation to the MISO peak, this could impact the need for
3 additional generation. By conservatively maintaining some additional system
4 length, we can absorb any sudden changes.

5
6 4) *Generation accreditation values and methodologies* – MISO has an annual process to
7 determine the actual capacity accreditation for existing units for the up-
8 coming year. All of our existing resources are subject to this annual process
9 which is based on the actual operational characteristics of the unit in the
10 previous year(s). This means that the amount of capacity that NSP can
11 actually count on can, and does, fluctuate from year-to-year. Therefore, as
12 our fleet ages and our plants perform differently from year-to-year, our
13 accredited capacity does tend to fluctuate. This is especially the case should
14 one of our plants have a high forced outage rate in a particular year, or, as
15 with the catastrophic failure of our Sherco 3 plant, not operate at all for some
16 particular reason. If and when this occurs, our capacity accreditation for that
17 plant is affected for a three year period going forward. In addition, MISO
18 has continuously been updating the capacity accreditation they have awarded
19 wind and solar as they continue to gain more experience with these resources.
20 As a result, the capacity value of our existing fleet has continued to change
21 over time, as noted by Mr. Polich.

22
23 5) *Viability of on-going programs (load management)* – While NSP’s load management
24 resource (demand response and interruptible sales) has historically been fairly
25 steady over time, MISO is reviewing how these customers should participate
26 in the market going forward. Also as more customers employ solar and as
27 rate structures and the value of these services change over time, there is the

1 potential that the amount of load management services will change over time.
2 An example of these possible changes occurred on our Southwest Public
3 Service Company system (in Texas and New Mexico) where nearly 200 MW
4 of load recently notified us that they were no longer interested in
5 participating. In a matter of months, the demand on that system went up by
6 nearly 200 MW on a system that is roughly 60% of the size of the NSP
7 system. If NSP experienced a comparable shift, it could result in about 300
8 MW of increased demand, roughly the size of the Mankato PPA.

9
10 Q. WHAT ABOUT THE OTHER POTENTIAL ISSUES ON YOUR LIST?

11 A. The other issues on my list relate to resource selection to meet a need or
12 maintain a conservative capacity cushion on the system. The majority of those
13 issues revolve around specific projects or alternatives. In the case of the
14 Mankato plant, the site already has natural gas access, it already has transmission
15 access, is permitted and we have a fixed price. Therefore, rather than face the
16 risk of having to go through years of MISO interconnection studies, or build
17 significant gas infra-structure, we have the opportunity to have a project that has
18 full assurance on all of these critical issues.

19
20 Q. HOW DO ALL THESE VARIABLES AFFECT THE COMPANY'S RESOURCE PLANNING
21 EFFORTS?

22 A. As you can see from the brief discussion above, a number of the rules that
23 govern our business are relatively new or have been in a state of flux over the
24 last five years. Since the future is not very clear on a number of these issues,
25 NSP has to stand ready to compensate for potential significant changes in our
26 resource requirements with minimal notice. This argues for maintaining a
27 reasonable amount of system length through conservative resource planning.

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Q. WHAT IS A REASONABLE AMOUNT OF SYSTEM LENGTH?

A. It depends on the circumstances and the level of uncertainty that exists. In general, with the number of changes we have experienced over the last five years and the high level of uncertainty that currently exists, maintaining an additional reserve margin of 250 to 300 MW for changes in demand forecasts and then an additional margin for the remainder of the potential concerns, above and beyond MISO’s minimum requirements, is reasonable in my opinion for the near-term period. The ultimate answer to this question is also highly influenced by the price and lumpiness of the alternatives that are being considered to supply additional flexibility. If the long-term price of the resource in question is very competitive, then I would lean to a higher level of resource acquisition. If the price of the resource is relatively high compared to historic levels for a similar resource, I may suggest staying closer to the 300 MW flexibility level. Since the price of the Mankato PPA is very economic from a comparable basis and it is not that lumpy (certainly not 500 MW to 700 MW lumpy), I would include this generator in my overall plan for system flexibility. In conclusion, for the NSP System and this generation resource, this translates into considering holding between 300 and 500 MW of additional length at this time. Given the evolving utility landscape and the aging of our fleet, I believe that it is reasonable for the Company to stay on the high side of this equation for some period of time, or until such time that the level of uncertainty subsides.

Q. DOESN’T MISO TAKE INTO ACCOUNT ALL OF THE VARIABILITY OF THESE ISSUES AND FACTORS WHEN IT SETS ITS RESERVE MARGIN?

A. No. MISO’s reserve margin calculations are based on the concept that the utilities’ forecasts will be reasonably accurate and that the utilities generation

1 model and outage rates will be similar to what they have been in the past. The
2 MISO reserve margin is really intended to compensate for the unplanned
3 outages and reduced availability of generation resource in the very next year,
4 along with higher loads due to temperatures (such as loads at the 90%
5 temperature probability level that can occur on very hot days) that are greater
6 than the load forecast at the median level (temperature levels at the 50%-50%
7 probability level) that are the basis for the resource planning criteria.

8
9 Q. HOW DOES THE AGE OF THE EXISTING FLEET IMPACT THE POTENTIAL NEED FOR
10 GENERATION RESOURCES?

11 A. The age of the existing fleet becomes more critical to our ability to meet our load
12 obligation as large assets in that fleet approach their end of their lives. Looking
13 to the future, a number of significant assets are approaching the end of their
14 lives, including Sherco units 1 and 2, our nuclear units and a number of our old
15 combustion turbines. While some of these assets will not retire for 10 to 15
16 years, the closer we come to the end of their lives the more likely that a major
17 equipment failure has the potential to bring a pre-mature end to a unit's life.
18 Due to the age of a number of units in our fleet, one has to start thinking about
19 additional contingencies in the case we need to shut a unit earlier than expected.

20
21 Q. WHAT DO YOU CONCLUDE FROM A REVIEW OF MR. POLICH TESTIMONY ON
22 THESE TYPES OF ISSUES AND YOUR ASSESSMENT OF THE CALPINE PROJECT IN
23 REGARDS TO THESE ISSUES?

24 A. It appears Mr. Polich attempts to suggest that a simplistic review of the
25 Company's Loads and Resources Table is all that one must take into account.
26 While he mentions that our forecasts have been updated, that we have continued
27 to update our existing resource capacity values, that MISO's requirements have

1 continued to evolve in regards to reserve margin and peak day design
2 requirements, and that we have continued to show these changes over the four
3 year resource plan evaluation and approval process, he seems to dismiss all of
4 these on-going uncertainties as if they are immaterial to determining the
5 prudence of making a resource addition at this time.

6
7 Certainly with the evolving utility landscape due to changing technologies,
8 potential emerging federal environmental regulation (including the Clean Power
9 Plan), along with all of the issues listed above, the decision to acquire additional
10 generation resources should not boil down to simply looking at a single number
11 on a Loads and Resources Table.

12 13 **III. VALUE OF MANKATO PPA TO SYSTEM**

14
15 Q. PLEASE SUMMARIZE THE BENEFITS OF THE MANKATO PPA FROM YOUR
16 PERSPECTIVE?

17 A. The Mankato PPA beginning in 2019 gives the Company significant optionality
18 and system flexibility at a very advantageous price. This value is particularly
19 important as we enter a period of increasing uncertainty due to increasing federal
20 environmental restrictions on coal generation and the number of issues I raised
21 earlier.

22
23 Q. WILL THE EXTRA CAPACITY REPRESENTED BY THE MANKATO PPA BE WASTED
24 FROM 2019 THROUGH 2024?

25 A. No. That capacity will be available to the Company for our use in the event our
26 forecast rebounds or one of the numerous other risks I identified becomes real
27 and the capacity is needed for our system.

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Q. ARE THERE LOCATIONAL BENEFITS FROM THE MANKATO PPA’S CAPACITY?

A. Yes. There are three.

First, building at the Mankato Energy Center allowed Calpine to take advantage of a preexisting site and to maximize the existing infrastructure. This efficient use of resources was largely responsible for the advantageous pricing. Mr. Johnson discusses the pricing benefits further in his testimony.

Second, the location is optimal from a system stability perspective. This plant is near Xcel Energy’s largest load center which contributes to system stability. Further, if in the future, Xcel Energy is called upon to retire one or more of its Twin Cities coal plants, it will be important to have this capacity available in the vicinity.

Third, the Calpine project has low cost natural gas access and existing transmission rights.

Q. YOU MENTIONED THE POTENTIAL RETIREMENT OF ONE OR MORE UNITS AT THE COMPANY’S COAL PLANTS. HAS THE COMPANY DECIDED TO RETIRE ANY OF THOSE UNITS?

A. At this time, no decision has been made. However, interested stakeholders have raised the issue in our current Resource Plan (2015 RP) with some requesting that one Sherco unit be closed as early as 2021. The Company is evaluating the potential for us to retire Sherco Unit 1 and/or Sherco Unit 2 potentially in the next 10 years. We will be filing comments in our current resource plan docket (Case No. PU-15-19) soon and expect to provide a more detailed discussion of

1 the Company's proposed plans for its Sherco units. In any case, it is prudent for
2 the Company to plan for a variety of outcomes; having the Mankato PPA
3 available to us provides substantial flexibility in a number of circumstances.
4

5 Q. IF THE COMPANY DOES NOT RETIRE EITHER OF THESE SHERCO UNITS, IS THE
6 MANKATO PPA STILL VALUABLE TO CUSTOMERS?

7 A. Yes. As I mentioned above, this capacity will be useful whether or not we retire
8 a unit at Sherco. The Mankato PPA capacity will provide a hedge against the
9 large number of uncertainties that we face and could be available to market to
10 other utilities if we ultimately do not need the incremental capacity in the
11 relevant timeframe.
12

13 Q. IS THE COMPANY SUPPORTING THE MANKATO PPA SIMPLY BECAUSE THE
14 MINNESOTA PUBLIC UTILITIES COMMISSION (MPUC) SELECTED THIS RESOURCE
15 IN THE CAP CON PROCEEDING (MPUC DOCKET NO. E-002/CN-12-1240)?

16 A. No. We acknowledge that a number of the issues I listed above were concerns
17 raised in the proceeding in Minnesota. In general the MPUC came to the
18 conclusion that by taking into account a number of the issues mentioned above,
19 including the demand forecasts, MISO reserve margins, non-coincident peak
20 reduction factors, and the potential changes to the future generation portfolio,
21 that it made sense to go ahead and acquire one of the most economical
22 combined cycles assets that had full gas availability and transmission access, in
23 2019 rather than wait and see what else may come along at a later date. The
24 MPUC had a very similar dilemma as the one that now faces this Commission.
25

1 Q. CAN THE COMPANY TERMINATE THE MANKATO PPA IF THE COMMISSION DOES
2 NOT DETERMINE IT IS PRUDENT?

3 A. Yes. The Mankato PPA contains a condition precedent that required that we
4 obtain regulatory approval from the Commission by a date certain.

5

6 We value the Commission's perspective on the prudence of this resource to our
7 overall integrated system. Further, we want to work constructively with the
8 Commission to balance the sometimes divergent energy policies among the
9 states in which we serve. To provide the Commission with the time necessary to
10 fully analyze this matter, the Company and Calpine agreed to extend that
11 condition precedent by several months. This means that the Commission's
12 decision can be obtained and fully internalized prior to that contractual deadline.

13

14 Q. CAN THE COMMISSION DENY AN ADP FOR RESOURCES PROPOSED BY THE
15 COMPANY THAT MEET A NEED IDENTIFIED BY ANOTHER STATE?

16 A. The Commission is charged to protect the interests of customers in North
17 Dakota and has the authority to consider the value of resources to our North
18 Dakota customers. However, when considering the overall value of the
19 resource, we think the Commission should include all of the considerations to
20 assess the value of the resource.

21

22 I note that the Commission recently denied our request for an ADP for the 187
23 MW solar portfolio (Case No. PU-14-810) and the Aurora solar project (Case
24 No. PU-15-95). The Company has not challenged the Commission's decision in
25 those cases.

26

27 Q. IF THE COMPANY ACCEPTS THE OUTCOME IN THE 187 MW AND AURORA SOLAR

1 PROJECTS, CAN IT ACCEPT A DENIAL IN THIS CASE AS WELL?

2 A. Unfortunately, Commission denial of this ADP would create a very difficult
3 situation for the Company to manage in a way that would better serve our North
4 Dakota customers. This is a very different situation than what we faced in the
5 solar projects and it is important to recognize that this different situation will
6 require different treatment.

7
8 Q. PLEASE EXPLAIN.

9 A. The Company worked hard to accommodate the Commission's concerns in the
10 187 MW portfolio and Aurora solar projects. We recognized the Commission's
11 energy policy concerns over the choice of relatively expensive solar generation
12 driven by Minnesota's solar energy standard is the archetypical type of resource
13 selection driven by the divergence of state energy policies. We accept that this
14 Commission will not approve these resources unless there is a solid economic
15 rationale behind them.

16
17 In the current Case, however, the issue at hand is not a divergence of state
18 energy policies but rather the prudence of the timing of making the Mankato
19 PPA resource addition now. As addressed in the record in this case, we believe
20 that weighing of all relevant factors argues for the prudence of this resource
21 addition now given its advantageous pricing and the uncertainty created by the
22 evolving utility landscape.

23
24 I urge the Commission to not view this resource as indicative of divergent
25 energy policies merely because it was selected through a different regulatory
26 process in Minnesota. While the CAP/CON process deviates from how
27 resources are evaluated and selected in North Dakota, its ultimate purpose is

1 consistent with North Dakota policies. Through the competitive bidding
2 mandated by the CAP/CON process the Company is able to evaluate both need
3 and cost in the selection of resource additions to its system. While the selection
4 of the Aurora project was driven by Minnesota specific considerations, the
5 selection of the Mankato PPA was not: it was selected as a least cost resource.

6
7 I also note that the CAP/CON process also resulted in the selection of the Black
8 Dog 6 combustion turbine project, which was also approved by this
9 Commission prior to the MPUC's decision.

10
11 Q. COULD THE COMPANY COME UP WITH A CREATIVE SOLUTION IN THIS CASE TO
12 ADDRESS THE TIMING OF THE MANKATO PPA?

13 A. The Company is open to creative solutions but at this time we have not
14 identified a viable one. First, the Mankato PPA is a capacity resource so should
15 be included in base rates. There is no special tariff or other program we could
16 divert this capacity to. Second, the financial impact of a rejection in this case
17 would be substantial and we do not believe could be reasonably absorbed.
18 Third, because of the capacity nature of the resource, attempting to carve out
19 this resource from the capacity balance for just the North Dakota share to reflect
20 the Commission's rejection, would potentially compel us to address the North
21 Dakota Loads and Resource Balance going forward differently than we would as
22 if it was part of the integrated system.

23
24 Fourth, in light of the significant value the Mankato PPA provides to our system,
25 it is important that this value be recognized. Granting the requested ADP would
26 be the best way to ensure that value is recognized and our North Dakota
27 customers obtain all of the benefits of their aliquot share of that capacity.

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Q. WHAT WILL HAPPEN TO THE CAPACITY IF THE COMMISSION DENIES THIS ADP?

A. Conceptually, for any resource that the Commission rejects, the Company should be free to use the capacity to its own account, without any residual rights back to North Dakota. Any contrary outcome would give North Dakota a free option to call on the capacity it has rejected.

However, because of the nature of the integrated system and the regulatory construct underlying how capacity is shared throughout the system, we are concerned that an ADP denial in this instance could effectively strand the capacity until North Dakota called upon it. This would be an inequitable outcome that requires more systemic changes to fully address and which cannot be addressed without significant changes to the rate making practices in North Dakota and the other states we serve.

IV. INTEGRATED SYSTEM CHALLENGES

Q. MR. POLICH CONCLUDES THAT THE MANKATO PPA IS NOT NEEDED TO SERVE THE COMPANY'S CUSTOMERS IN NORTH DAKOTA. DOES HIS TESTIMONY HAVE IMPLICATIONS ON THE COMPANY'S INTEGRATED SYSTEM?

A. Yes. While it is entirely appropriate for the Commission to focus on North Dakota considerations and the impact on North Dakota customers in assessing the requested ADP, I am concerned that relying exclusively on those in-state considerations may potentially create a detriment for the very same North Dakota customers.

Q. BUT IF THE COMMISSION CONCLUDES THAT THIS RESOURCE IS NOT NEEDED

1 UNTIL 2025, IT COULD DENY THE ADP, COULD IT NOT?

2 A. Yes. The Commission could find that the Company does not need the Mankato
3 PPA to serve its North Dakota customers. However, we are concerned that
4 such an outcome would make it increasingly difficult for the Company to
5 maintain its multi-state integrated system. We believe that the challenges
6 incumbent with that outcome are more appropriately addressed on a more
7 holistic basis and not through the assessment of prudence of a particular
8 resource.

9
10 Q. WHAT WILL HAPPEN IF THE COMMISSION DENIES THE ADP?

11 A. It remains unclear. At the very least, if the Commission denies the ADP, we will
12 be left with two difficult choices – terminate the Mankato PPA or proceed with
13 it and somehow carve the North Dakota share of the capacity out of the
14 contract. Neither of these choices is consistent with the long-term interests of
15 our customers, and in particular the interests of our North Dakota customers.

16
17 Q. BUT IF YOU DO NOT NEED THE CAPACITY, THEN ISN'T TERMINATING THE PPA
18 THE BEST OUTCOME?

19 A. One could extrapolate that from Mr. Polich's Testimony. However, Xcel
20 Energy disagrees with him on his ultimate conclusion. We conclude that the
21 Mankato PPA is in customers' overall interest under the totality of the
22 circumstances presented here. We think this resource further provides value to
23 our North Dakota customers in the form of the optionality and flexibility it
24 provides.

25

1 **IV. UPDATE ON RESTACK**

2
3 Q. PLEASE SUMMARIZE THE RESTACK CONCEPT FOR THE COMMISSION.

4 A. As part of the settlement we reached with Staff in our last rate case (Case No.
5 PU-12-813), we agreed with Staff to develop a negotiated agreement that adjusts
6 rates charged to North Dakota customers based on a resource mix that is more
7 consistent with North Dakota energy policies. The settlement included a
8 framework and list of general principles to guide the negotiations and imposed a
9 deadline of June 30, 2015 for the Company and Staff to complete the negotiated
10 agreement. Subsequently the Commission extended the deadline for completing
11 the negotiated agreement to September 30, 2015.

12
13 Q. WHAT IS THE STATUS OF THE NEGOTIATED AGREEMENT?

14 A. The Company and Staff have worked diligently to implement the principles in
15 the settlement. We have explored options for “restacking” the supply portfolio
16 to better match our resources to North Dakota’s policy preferences. This task
17 has proved challenging to implement within reasonable financial constraints. As
18 a result, the Company and Staff are exploring additional broader options that
19 could, if successful, provide additional incentives for the Commission. We
20 expect to file a “Negotiated Agreement” on September 30, 2015.

21
22 **VI. CONCLUSION**

23
24 Q. WHAT DO YOU RECOMMEND?

25 A. I recommend that the Commission accept the Mankato PPA. The combination
26 of advantageous pricing and the flexibility this resource provides the overall
27 system outweigh the timing concerns raised by Mr. Polich. Further, the cost and

1 other implications of denying this resource raise serious questions about the
2 long-term viability of the Company's integrated system. As a result, the
3 Company respectfully urges the Commission to grant the requested ADP and
4 facilitate the long-term success of the integrated system to the overall benefit of
5 our North Dakota customers.

6

7 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

8 A. Yes, it does.

**STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION**

IN THE MATTER OF THE APPLICATION
OF NORTHERN STATES POWER
COMPANY FOR AN ADVANCE
DETERMINATION OF PRUDENCE FOR
A POWER PURCHASE AGREEMENT
WITH MANKATO ENERGY CENTER,
LLC FOR APPROXIMATELY 345 MW OF
COMBINED-CYCLE NATURAL GAS
GENERATION

Case No. PU-15-96

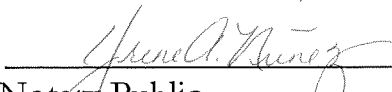
STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Kurtis J. Haeger, being first duly sworn on oath, deposes and says that he is Area Vice President of Resource Planning for Xcel Energy Services Inc., the service company subsidiary of Xcel Energy, in the above captioned matter, that he has read the Rebuttal testimony and schedules submitted in the above captioned matter under his name, that they were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.



Kurtis J. Haeger

Subscribed and sworn to before me this 11th day of September, 2015.



Notary Public
My Commission Expires: 9/28/2016

**YRENE A NUÑEZ
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 19874149394
MY COMMISSION EXPIRES SEPTEMBER 28, 2016**

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Rebuttal Testimony and Schedules
Paul B. Johnson

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company's
Advance Determination of Prudence for its 345 MW Power Purchase Agreement
with Mankato Energy Center, LLC

Case No. PU-15-96
Exhibit____(PBJ-2)

Rebuttal of Advocacy Staff (Polich) Testimony

September 11, 2015

Case No. PU-15-96
Johnson Rebuttal

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I. INTRODUCTION

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- Q. PLEASE STATE YOUR NAME AND TITLE.
- A. My name is Paul B. Johnson. I am Director of Resource Planning and Bidding for Xcel Energy. I provided Direct Testimony in this matter on a variety of resource planning issues.
- Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?
- A. I respond to specific issues raised in the Direct Testimony of Richard A. Polich, P.E. on behalf of the Commission Advocacy Staff. I also provide information on how the addition of the Mankato PPA in 2019 is a reasonable resource addition under the circumstances.
- Q. PLEASE SUMMARIZE YOUR TESTIMONY.
- A. Mr. Polich provides a resource planning analysis narrowly focused on the Company's load and resources in the 2019-25 timeframe. He concludes that the Company does not need additional capacity until the 2025 timeframe. He recommends that the Commission deny the ADP for the Mankato PPA commencing in 2019.
- Mr. Polich states that the Company has a capacity need in 2025. Based on the current loads and resources forecast, I conclude the Company has a capacity need in 2024.
- Given this need in 2024, the Company concludes that carrying the Mankato PPA from 2019 to 2023 is overall a better deal for ratepayers than deploying a combustion turbine (or combined-cycle) unit in 2024 to meet the outyear need. The Mankato PPA is aggressively-priced and provides us combined-

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1 cycle capacity and energy at about the equivalent overall cost of a combustion
2 turbine and its associated energy. In addition, adding combined-cycle capacity
3 to the system provides optionality and flexibility to address a number of
4 evolving circumstances as I describe later in this testimony.

5
6 We acknowledge that the timing of the Mankato PPA is not ideal as the
7 generation comes on line a few years prior to the need indicated by Mr.
8 Polich’s Table C. However, Mr. Polich substantially overstates the cost of
9 deploying the Mankato PPA in 2019 and he ignores all of the other risks and
10 benefits that provide value in moving forward at this time.

11
12 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

13 A. Mr. Polich’s testimony addresses four main topics: (i) forecast issues, (ii) 2019-
14 2024 capacity obligations, (iii) North Dakota ratepayer impacts, and (iv)
15 capacity risks. While my Rebuttal Testimony addresses each of those topic
16 areas, I have structured this testimony to focus on the benefits of the Mankato
17 PPA and the problems we have identified in Mr. Polich’s analysis. These
18 topics are:

- 19 • Load and Resource Discussion;
- 20 • Mankato PPA Cost Impact;
- 21 • Capacity Risks;
- 22 • Conclusion.

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II. LOAD AND RESOURCES DISCUSSION

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Q. MR. POLICH TESTIFIES THAT NEW CAPACITY IS NOT NEEDED UNTIL 2025
BASED ON HIS REVIEW OF THE 2015 FORECAST. HOW DO YOU RESPOND?

A. First of all, the Company accepts, for purposes of this case, Mr. Polich’s
premise that the most up-to-date forecast should be used. The Company has
prepared an up-to-date load and resources table based on the 2015 IRP
forecast which is shown below on Table 1. Table 1 shows that with the
Company’s current resources, it has a capacity need in 2024 of 165 MW.
Adding the Black Dog 6 project, but removing the resources not approved by,
or likely not to be approved by, the Commission results in a forecasted
capacity need of 117 MW in 2024.

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1 **Table 1: Updated Load and Resources**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Obligation (MW)															
Peak (MW)	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Peak	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation (MW)	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
Generation Resources															
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,576	2,325	2,090	2,090	2,090
Biomass/RDF/Hydro/Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
RDF/Biomass - Owned	96	96	96	96	96	96	96	96	36	36	36	36	0	0	0
Biomass/RDF - PPA	145	145	122	110	109	109	109	84	84	84	80	47	0	0	0
Wind - PPA	181	181	181	157	157	215	215	193	180	158	152	140	135	118	117
Wind - Owned	48	48	48	48	48	99	99	99	99	99	99	99	99	99	99
Hydro - Owned	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Hydro - PPA	791	788	788	788	715	837	830	830	830	3	3	3	3	3	3
Solar	25	131	137	143	149	156	165	175	187	202	220	241	268	301	339
2014 Solar RFP	0	97	97	97	96	95	95	94	94	93	93	92	92	91	90
Solar Community Garden	5	9	11	13	16	19	23	27	31	37	44	52	63	76	90
Geronimo/Aurora	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Solar	4	4	4	4	4	4	3	3	3	3	3	3	3	3	3
Small Solar	16	21	25	29	34	38	44	51	59	68	80	94	111	131	156
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Existing Resources	9,846	10,004	9,999	9,969	9,913	10,164	10,177	10,151	9,772	8,627	8,383	8,104	7,803	7,814	7,846
Current Position	239	314	235	152	71	301	253	232	-165	-1,341	-1,658	-2,032	-2,510	-2,515	-2,584
All Planned Resource Additions															
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine MEC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geronimo	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Small Solar SES	-1	-1	0	1	3	4	4	4	2	4	4	4	4	4	3
Community Solar Gardens	20	36	53	72	94	103	103	102	102	101	100	100	99	98	98
Total Additional Resources	19	35	123	351	374	384	384	382	380	381	379	379	378	375	375
Forecasted Position	258	349	358	502	445	685	636	615	215	-961	-1,279	-1,653	-2,132	-2,139	-2,209
Resources Removed Due to NDPSC Decisions															
Pleasant Valley Wind	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30
Geronimo	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
2014 Solar RFP	0	97	97	97	96	95	95	94	94	93	93	92	92	91	90
Other Disallowed Resources (1)	151	151	151	139	139	168	168	143	143	143	139	106	56	50	49
Total Resources Removed	151	249	318	305	304	362	361	335	334	333	328	295	243	237	235
Forecasted Position	106	100	40	197	141	323	275	279	-120	-1,294	-1,607	-1,948	-2,376	-2,376	-2,444

(1) Other Disallowed Resources - KODA Energy LLC, WM Renewable Energy (MN Methane), Pine Bend, Jeffers Wind 20, LLC, Big Blue, Community Wind South (Zephyr), Ridgewind Power Partners LLC, Adams Wind Generators, Danielson Wind Farms, Ewington Energy Systems LLC, Grant County Wind, LLC, North Community Turbines, North Wind Turbines, Valley View Transmission, Ulk Wind Farm, Hilltop Power, Winona County Wind, Woodstock Municipal Wind LLC, Odell, Ourland Solar (Slayton), Best Power (St. John's), FibroMinn, Laurentian Energy Authority, St. Paul Cogeneration

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We also disagree with his recommendation that the Commission deny the requested ADP for the Mankato PPA prior to a forecasted clear deficit – in his case 2025, or 2024 based the current forecast. When all of the relevant factors are considered, the Mankato PPA beginning in 2019 is a prudent choice.

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1 Q. WHY DO YOU STATE THE FORECASTED CAPACITY DEFICIT IS 2024 RATHER
2 THAN 2025?

3 A. Mr. Polich adjusts his L&R table to remove the resources that the
4 Commission has (or is likely to) denied. I agree with that approach. If the
5 Commission is not going to accept a particular resource then that resource
6 should not be included in the calculation. To do otherwise would give North
7 Dakota credit for resources that it is not paying for. Mr. Polich removed
8 certain resources from his L&R, but neglected to include the other resources
9 that the Commission has not approved. When the full set of resources are
10 removed, the need occurs in 2024.

11

12 Q. MR. POLICH CITES THE CHANGING NATURE OF NSP'S FORECASTED NEED, DO
13 YOU CONCUR?

14 A. In developing his Table A and Table B, Mr. Polich accurately identifies an
15 important point - forecasting future capacity needs is a consistently changing
16 process. Many components that go into developing a need forecast change
17 over time: load forecasts, MISO rules, methodology for determining the
18 accredited capacity of current resources, and regulatory decisions regarding
19 resources are examples. Although his assessment is sound, I disagree with
20 portions of his analysis in Tables A and B. Unfortunately some of the data
21 provided by the Company may have contributed to some of this confusion.
22 The data we provided to Mr. Polich reflected forecasts and loads and
23 resources tables that incorporated the current state of the planning "rules" at
24 the time of the forecast. As a result, when comparing the six forecasts used in
25 Table A, one must understand that several changes were made in both the
26 calculations and reporting structure of the forecasts over time. Existing
27 resources were changed from being reported as installed capacity ("ICAP") to

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1 unforced capacity using the MISO methodology (“UCAP”). The
2 methodology of projecting future UCAP ratings, as well as the actual UCAP’s
3 of the units themselves evolved. Additionally, in earlier forecasts generic
4 “expansion plan” units were lumped into the total resources line where in later
5 forecasts they were not.

6
7 Specifically, the line item “2010 IRP Forecast” in Table A was created with an
8 ICAP planning reserve margin and corresponding ICAP resource ratings. The
9 remaining lines of the table utilize UCAP planning reserve margin and UCAP
10 resource ratings. Therefore, a direct comparison of the “2010 IRP Forecast”
11 line and all other Forecasts on Table A cannot be made.

12
13 In addition, the impact of MISO’s 2015/2016 planning reserve margin
14 requirement and relatively new coincident peak methodology has impacted the
15 system need by approximately 200 MW as compared to the prior obligation
16 planning methodology. This MISO change to incorporate a non-coincident
17 reduction factor in 2013 largely accounts for the difference between the
18 second through fourth forecast in Table A (Fall 2011 Forecast, Fall 2011
19 Forecast 2 (Case Forecast) and Spring 2013 Forecast) and the last two
20 forecasts listed (Fall 2014 Forecast and the 2015 IRP Forecast). In conclusion,
21 while Mr. Polich attempted to compare the Company’s forecasts as they
22 evolved over time Table A of his testimony, he did not provide the context of
23 how the forecasts were being updated to take into account the numerous
24 changes that were occurring with the system and the MISO rules.

25 Q. BEGINNING ON PAGE 14 OF HIS TESTIMONY MR POLICH RESPONDS TO THE
26 QUESTION – “DOES TABLE 2 ON PAGE 10 OF MR. JOHNSON’S TESTIMONY USE
27 THE MOST CURRENT FORECAST OF MISO CAPACITY OBLIGATION AND NSP’S

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1 AVAILABLE GENERATION RESOURCES?” DO YOU AGREE WITH HIS RESPONSE?

- 2 A. No, I disagree with Mr. Polich response. The basis for Table 2 was the most
3 current forecast of MISO capacity obligation and NSP’s available generation
4 resources at the time. Table 2 in my Direct Testimony was prepared in a way
5 to demonstrate a System Capacity Forecast in conformance with the
6 methodology we used to respond to Mr. Diller’s IR Request DR-NDPSC-011
7 in Case No. PU-14-810 (Solar ADP Case).

8
9 Mr. Polich did not account for the resource adjustments shown by Table 1
10 above which results in a forecasted capacity need of 117 MW in 2024. This
11 capacity need reflects resource decisions of the NPPSC, thus the removal of
12 these resources resulting in the 117 MW capacity need in 2024. These
13 adjustments not made by Mr. Polich explain the difference in his 149 MW
14 capacity long position in 2024 in Table B of his testimony and Table 1 above.

15
16 Table B Line “2015 IRP Forecast**” reflects the Company’s January 2015
17 filing of the 2016-2030 Resource Plan. Resources excluded from this position
18 include Black Dog 6, Mankato PPA, Geronimo/Aurora, growth in Small Solar
19 projects. Resource included this position include the 187 MW Solar portfolio,
20 all 2013 RFP Wind projects (Pleasant Valley, Odell, Courtenay, Borders), and
21 all previously ND disallowed PPA’s subject of the last rate case PU 12-813.

22
23 Table B Line “2015 IRP Adjusted Forecast***” reflects Polich’s adjustments
24 to the line “2015 IRP Forecast” with the additions of Black Dog 6, and
25 growth in Small Solar.

26

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1 The system will benefit from the Small Solar resources, however the ND
2 ratepayer will not be paying for these resources as agreed to by the MPUC.
3 Small Solar is projected to grow from meeting 1.1 percent (110 MW) of
4 system obligation in 2020 to 1.4 percent (138 MW) in 2025.

5
6 Q. ISN'T IT SUFFICIENT TO RELY EXCLUSIVELY ON THE MISO-REQUIRED
7 RESERVES AND NOT HAVE ANY ADDITIONAL AMOUNT?

8 A. While the MISO reserve margin does supply some measure of risk protection,
9 in many cases, or even typically, it may be prudent to carry excess reserves
10 above the MISO-determined minimum level. As Mr. Haeger describes in his
11 Rebuttal Testimony, the Company believes carrying excess reserves up to 2 to
12 3 percent above MISO's minimum requirements could be considered prudent
13 if the level of shifts in capacity need experienced over the past few years
14 continues. In addition, with the potential for new and significant impacts
15 from the Clean Power Plan, additional MISO changes and potential for other
16 more restrictive and costly impact on predominantly coal generation, Mr.
17 Haeger also believes these types of circumstances and risks to the system
18 support adding the additional 278 MW (UCAP) from the Mankato PPA is
19 prudent and reasonable. Overall this would result in capacity long position of
20 up to about 600 MW in some years. .

21
22 Q. WHY DOES THE COMPANY TAKE THE POSITION THAT CARRYING THE MISO-
23 MINIMUM RESERVE MARGIN MAY BE INSUFFICIENT?

24 A. Because MISO annually determines reserve margin requirements, any changes
25 in member forecasts and MISO's methodology used to determine the reserve
26 margin requirement could be significant. MISO's role is to analyze the system
27 on a footprint-wide basis and doing so, relies on the forecasts provided by the

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1 member systems. MISO assumes that resources will be available as described
2 by the utilities and that they will be available in the same manner as they have
3 been historically. The MISO reserve margin is focused on very near term
4 reliability – if conditions change substantially further out in time, today’s
5 reserve margin may not be sufficient to address the impact of actual changes
6 in future customer demand and generation availability . Therefore, when
7 planning to maintain reliability years into the future, as is required due to the
8 long lead time to procure new resources, some measure of risk protection is
9 prudent.

10
11 The Company believes in this time of unprecedented uncertainty in resource
12 planning due fluctuating load and economic forecasts, evolving environmental
13 policies, and uncertainty in MISO requirements that it is prudent to carry
14 some additional capacity above and beyond the MISO minimum to mitigate
15 risk.

16
17 Q. ARE THERE OTHER REASONS THAT SUPPORT SELECTING THE MANKATO PPA
18 IN 2019?

19 A. Yes. The Rebuttal Testimony of Mr. Christopher Clark and Mr. Kurtis
20 Haeger provide a summary of the benefits of installing the Mankato PPA
21 capacity in 2019, rather than deferring a capacity addition to 2024. Under all
22 of these circumstances, having a somewhat higher capacity long position could
23 prove to be advantageous and is certainly prudent. Commission approval of
24 the Mankato PPA would provide capacity price certainty and allow selection
25 of a well-priced project with reliable gas delivery and transmission service that
26 captures the economies of an existing gas generation site initially designed for
27 this expansion. My testimony provides support for some of those factors.

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2 Q. IS THE TIMING OF POWER GENERATION EQUIPMENT A RELEVANT CRITERION
3 IN SELECTING AND DEPLOYING A RESOURCE?

4 A. Yes. Deploying major electric generation is a time-consuming endeavor that
5 requires advance planning and considerable effort. It is not reasonable to wait
6 until the need actually materializes to begin the process, because at that point
7 it will be too late. Thus, we necessarily must rely on forecasts to determine if
8 it is prudent to proceed with making additions to our systems,
9 notwithstanding their potential to vary from actual outcomes.

10

11 Q. IS THE SIZE OF A UNIT A RELEVANT CRITERION ON WHETHER AND WHEN TO
12 DEPLOY A RESOURCE?

13 A. Yes. It is necessary to consider resources that meet an identified need at
14 reasonable costs overall. Economies of scale suggest that building somewhat
15 more capacity than is entirely needed at that time to meet customer demand
16 can be advantageous. As a result, power plant development tends to be
17 somewhat “lumpy.”

18

19 Q. WHAT DO YOU MEAN BY “LUMPY.”

20 A. Demand growth is not smooth and will not necessarily track the most
21 efficiently-sized power plants. For example, if a utility has an identified need
22 of 100 MW but the most reasonable solution overall is to build a 200 MW
23 unit, then the extra 100 MW “lump” goes beyond the nominal need. The 200
24 MW generator may well be the best choice even with the excess capacity as it
25 might be more efficient and more cost-effective overall than deploying two-
26 50 MW reciprocating engines or a 100 MW unit. The lumpy capacity remains
27 available both for the system and perhaps to be sold to other utilities who may

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1 need additional capacity but want to defer building their own generation.
2 Ultimately, load growth over time and system sales in the near term tends to
3 absorb the extra capacity that is created by this lumpy development cycle.
4

5 Q. IS THE SELECTION OF THE MANKATO PPA CONSISTENT WITH THIS NOTION OF
6 LUMPY DEVELOPMENT?

7 A. Conceptually, yes. In analyzing the costs and benefits of the Mankato PPA, it
8 is necessary to consider the same factors of timing, cost, potential sales and
9 ultimate use of the resource. While in this case, the Mankato PPA capacity is
10 being deployed somewhat prior to the currently identified need, it serves those
11 same purposes.
12

13 Q. IS PRICING OF THE RESOURCE A RELEVANT CONSIDERATION IN DECIDING
14 WHETHER AND WHEN TO DEPLOY A RESOURCE?

15 A. Yes. The price is highly relevant and can influence the timing of a resource as
16 there can be circumstances where an advantageous price justifies deploying a
17 resource early to capture pricing benefits that might otherwise be unavailable.
18 Similar to considerations of building extra or lumpy capacity to capture
19 economies of scale, an advantageous price can and should influence the timing
20 of new resources.
21

22 Q. IS THE MANKATO PPA COMPETITIVELY PRICED?

23 A. Absolutely, on an overall basis. Typically, combustion turbine capacity is
24 cheaper to install but more expensive to operate than combined-cycle
25 capacity. In this instance Calpine's combined-cycle proposal was very
26 competitively priced. Essentially, by taking the Mankato PPA the Company is
27 able to obtain combined-cycle capacity with its more efficient and cheaper

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1 energy production at virtually the same costs for a similar amount of
2 combustion turbine based capacity.

3
4 Q. HOW DO YOU KNOW THAT THE CALPINE PROPOSAL IS COMPETITIVE WITH A
5 LESS-EFFICIENT COMBUSTION TURBINE?

6 A. In the Minnesota CAP/CON Proceeding (MPUC Docket No. E-002/CN-12-
7 1240) in which the Mankato PPA was chosen, we received competing bids
8 from other parties for combustion turbine capacity. Specifically, we received a
9 bid from Invenenergy to add combustion turbine capacity at a preexisting site.
10 The evaluated cost (i.e. total system cost on a present value of revenue
11 requirements basis) of the Invenenergy combustion turbine proposal was very
12 close to the evaluated cost of the Calpine combined-cycle. In addition, Xcel
13 Energy proposed to install combustion turbines in Hankinson, North Dakota.
14 The evaluated cost of that project was higher than the Calpine proposal.
15 Finally, I reviewed industry sources for generic combustion turbine
16 installations of the type used for modeling in our resource plan. These generic
17 resources were generally higher priced than the bids we received in the
18 CAP/CON Proceeding.

19
20 Thus, the Mankato PPA is highly competitive with a range of combustion
21 turbine options that were available to us. Based on this, I conclude that the
22 Mankato PPA beginning in 2019 is competitively priced while also providing
23 significant optionality and flexibility benefits as described by Mr. Clark and
24 Mr. Haeger.

25
26 Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

27 A. Assuming the relative options remained available, the Mankato PPA would

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1 also compare favorably to a combustion turbine deployed in 2024. But then
2 we would lose the price certainty of the Mankato PPA and the energy
3 production efficiency and flexibility inherent with a combined-cycle unit. On
4 balance, I conclude that it is better to lock in the price certainty and other
5 benefits of the Mankato PPA than to wait to 2024.

III. MANKATO PPA COST IMPACTS

6
7
8
9 Q. DO YOU CONCUR WITH MR.POLICH’S TESTIMONY REGARDING THE NORTH
10 DAKOTA RATEPAYERS COST IMPACT?

11 A. Generally, no. NSP agrees that using up-to-date forecast data is appropriate,
12 and also agrees that the reference case should include the already-approved
13 Black Dog 6 project. However, we do not agree with either the cost impacts
14 of the project or the methodology Mr. Polich used to arrive at his figures.

15
16 Q. WHAT ARE YOUR CONCERNS WITH MR. POLICH’S CALCULATIONS?

17 A. My concern is that Mr. Polich appears to have estimated the cost impacts
18 using spreadsheet adjustments of the modeling data supplied by the Company
19 based on his understanding of the data and what each data element
20 represented. Unfortunately his interpretation of some of the data was
21 incorrect, leading to a flawed methodology in his calculations. The data from
22 the Company including catagorized cost information with short generic labels.
23 Without a full explanation of all the costs in each category, it could be
24 somewhat difficult to interpret. Due to his interpretation the results presented
25 in Table E are incorrect and cannot be added to the results in Table D.

26
27 As an example, Mr. Polich ultimately concludes that the Mankato project

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1 causes increased costs of over \$246 million for the integrated system through
2 2024 (see Polich, Table F, sum of line # 3 on p. 23), yet the sum of the total
3 fixed costs of the project for the same years is only about [**TRADE**
4 **SECRET BEGINS** **TRADE SECRET ENDS**]. This amount
5 would be the highest the incremental cost could ever be, representing a highly
6 unlikely scenario where the project was never dispatched economically at all.
7 Any energy or capacity benefits from adding the efficient combined cycle
8 resource to the system can only reduce the costs from there. The fact that Mr.
9 Polich arrived at a figure almost 1.5 times the actual fixed costs demonstrates
10 the dangers of using more simplistic methods to conduct these complex cost
11 analyses.

12
13 Q. WHAT DO YOU BELIEVE LED TO THE ERROR IN TABLE E?

14 A. In developing Table E Mr. Polich cites a variable O&M avoided cost
15 reduction value in 2019 of \$46.40/MWh, which he concludes is around
16 \$40/MWh too high as compared to an actual unit's variable O&M costs. He
17 thus makes a downward adjustment of \$40/MWh for all years 2019-2024. Mr.
18 Polich's error is that he appears to have assumed a data labeled "O&M" was
19 variable O&M, which was incorrect. The data he is citing is actually the
20 difference in fixed costs between modeling runs "with" and "without" the
21 Mankato project. These fixed costs include both the the avoided capacity cost
22 of future expansion units which are treated as purchase power agreements for
23 modeling purposes and the "surplus capacity credit" modeling construct
24 which is explained later. Thus, comparing this value to other thermal unit's
25 variable O&M costs is meaningless

26
27 Additionally, Mr. Polich cites the avoided energy cost reduction value in 2019

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1 of \$69.81/MWh from the same source. He compares it to the operating
2 characteristics of a new construction combustion turbine from our recent IRP,
3 which he states as \$57.56/MWh, and determines the cost to be higher than
4 what would be expected. While unclear, the Company believes he determined
5 the operating cost of the new unit from a typical calculation of “(heat rate *
6 gas price) + variable O&M” formula.

7
8 It appears he is missing two important points. First, avoided start up costs are
9 embedded in the Company’s avoided energy cost numbers, and appear to be
10 missing from his comparison. This can typically add at least \$10/MWh to a
11 combustion turbine’s variable operating cost. Data for startup costs were not
12 provided in the IRP, and correcting for the missing startup costs in Mr.
13 Polich’s calculation raises the IRP combustion turbine’s cost quite close to the
14 calculated avoided energy cost, erasing the discrepancy he noted.

15
16 Additionally, the interactions of the Mankato project with the rest of the
17 Company’s resources and expansion plans is highly complex. Analyses such
18 as the overall cost/benefit of a specific resource without using a simulation
19 tool such as the Strategist model used by the Company misses these important
20 interactions and can lead to incorrect conclusions. Mr. Polich was attempting
21 to use the model information he had requested to approximate costs and
22 savings under different scenarios than the model output provided, but
23 ultimately it is necessary to re-run the model to accurately determine those
24 results.

25
26 Q. ON PAGE 22 OF HIS TESTIMONY, MR. POLICH EXPRESSES CONCERNS ABOUT
27 THE VALUES USED TO POPULATE TABLE 7 OF YOUR INITIAL TESTIMONY. DO

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1 YOU AGREE WITH THOSE CONCERNS?

2 A. The Company is unclear what Mr. Polich is referring to. The data used to
3 populate Table 7 in my testimony already did take into account the partial year
4 of operation for 2019.

5

6 Q. DID THE COMPANY UPDATE THE MODELING RESULTS BASED ON MR. POLICH'S
7 RECOMMENDATIONS?

8 A. We did. The Company has modeled the costs/benefits of the Mankato
9 project using the same methodology as in my previous testimony, except with
10 including Black Dog 6 in the base case and using our updated 2015 IRP
11 Strategist model.

12

13 Q. WHAT ARE THE RESULTS OF THE REVISED MODELING?

14 A. The overall costs/savings are as shown below in Table 1.

15 **Table 1: Calpine Mankato Expansion PPA Overall Economics**

16 **[TRADE SECRET BEGINS**

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26 **TRADE SECRET ENDS]**

27 As can be seen, when we do the correct calculations, and only consider a

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1 “carrying” period through 2023 based on the correct Loads and Resources
2 table, the net costs are \$33 million. This is a comparable value to Mr. Polich’s
3 estimated \$39 million in his Table D. Using the forecasted North Dakota load
4 allocators, this represents about [TRADE SECRET BEGINS
5 TRADE SECRET ENDS] for North Dakota customers.

6
7 Q. HOW ARE THE REVISED RESULTS COMPARABLE TO MR. POLICH’S TABLE E?

8 A. In developing Table E, Mr. Polich’s intent was to correct the modeling for
9 discrepancies that did not match the operating costs of physical units. A
10 significant portion of why he noticed a discrepancy is that the modeling by the
11 Company typically includes a credit for surplus capacity on the system. When
12 this credit is removed from Table 1, the overall costs are \$106 million. This
13 would be comparable to his calculation of \$246.6 million. Using the forecasted
14 North Dakota load allocators, this represents about \$5.6 million for North
15 Dakota customers.

16
17 Q. CAN YOU PLEASE ELABORATE ON THIS “SURPLUS CAPACITY CREDIT”?

18 A. The surplus capacity credit is a modeling construct the Company uses in
19 Strategist to reflect the estimated economic value of extra length in the system.
20 Having extra length in the system indisputably has economic value – both
21 readily monetizable, such as providing the ability to sell a portion of excess
22 capacity in the market, as well as a hedge against unexpected future capacity
23 needs. It also represents the value of deferring the need to add resources on
24 our’s and our neighbor’s systems in the future.

25
26 For purposes of modeling, the Company uses the estimated capacity payment
27 for a new-build combustion turbine purchase power agreement to represent

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1 this value, recognizing that over the long-term, the costs of marginal capacity
2 in an open market should converge to approximately this cost. The Company
3 presents the revised economics of the Mankato project with this item
4 delineated separately to provide greater transparency.

5
6 Q. HOW DOES THE REVISED MODELING IMPACT THE LEVELIZED COST AND RATE
7 IMPACT CALCULATIONS PRESENTED IN YOUR DIRECT TESTIMONY ?

8 A. Updated levelized cost and rate impact tables comparable to those presented
9 in my direct testimony are included in Schedule A.

10
11 **IV. FLEXIBILITY AND OPTIONALITY**

12
13 Q. DID THE COMPANY IDENTIFY ANY OTHER BENEFITS OF THE MANKATO PPA?

14 A. Yes. The Mankato PPA provides value in a number of ways by providing
15 both flexibility in optimizing the system and optionality to address uncertain
16 and evolving circumstances. There are at least three areas where adding
17 combined-cycle generation in 2019 adds value:

- 18 • Allows us to consider accelerating retirement of some old peakers;
- 19 • Allows us flexibility to address upcoming baseload retirements; and
- 20 • Provides optionality to defer future units in a tight capacity market.

21
22 1. Early Retirement of Peakers

23 Q. PLEASE DESCRIBE THE POTENTIAL TO RETIRE THE OLDER PEAKERS EARLY.

24 A. Adding 278 MW (accredited) of capacity in 2019 could allow us to proactively
25 retire about 270 MW of older peakers to optimize the system, as well as
26 providing a contingency should these older units fail prematurely, which is a
27 possibility given their age. Retiring the older peakers would also save

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1 incremental O&M expense and ongoing capital during the 2019-2024 period.
2 In exchange for that saving, we would obtain new combined-cycle capacity
3 and more efficient energy production.

4
5 The addition of the Mankato PPA would enable the earlier (2019 rather than
6 2024) retirement of about 270 MW of old, less efficient combustion turbine
7 capacity with high operating costs and that, due to their age, have an increased
8 risk of a major equipment failure and increased difficulty in finding
9 replacement parts.

10
11 I note that Mr. Polich identified our Blue Lake, Granite Falls and French
12 Island peakers as being slated for retirement in 2024. We agree and think it
13 may add value to retire those peakers early if we can do so at a reasonable
14 cost.

15
16 It should be noted that the French Island combustion turbines are not eligible
17 for retirement before 2024, due to reliability and fuel supply contract
18 requirements. NSP has evaluated its older combustion turbines and has
19 determined that retiring Blue Lake Units 1-4, Granite City Units 1-4 and
20 Wheaton Units 5 & 6 in 2019 rather than 2024 would be possible if the
21 Mankato PPA was approved. Eliminating these older combustion turbine
22 units in 2019 could have a material positive impact on our system, and even in
23 the case where early retirement is not determined prudent, any one of these
24 older units may catastrophically fail much earlier than 2024.

25
26 2. Baseload Retirements

27 Q. HOW DOES ADDING THE MANKATO PPA CAPACITY IMPACT THE RISK OF

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1 BASELOAD RETIREMENTS?

2 A. Adding the Mankato PPA capacity to the system provides added flexibility in
3 an era of increasing uncertainty over coal generation and the ongoing costs of
4 the nuclear fleet. In the event that one or more baseload plants is retired on
5 the Company's system in the next decade, having the Mankato PPA capacity
6 would help avoid the higher revenue requirement (rate impact) and greater gas
7 price risk of having to add new combined-cycle capacity.

8

9 Without the Mankato PPA's capacity available to us we may be constrained to
10 choose more expensive or less flexible options for replacing baseload capacity.

11

12 Q. PLEASE DESCRIBE THE VALUE OF THE MANKATO PPA WITH RESPECT TO THE
13 REDUCTION OF EXISTING BASELOAD AND INTERMEDIATE CAPACITY
14 RESOURCES ON THE COMPANY'S SYSTEM.

15 A. From 2015-2030, the NSP System will experience significant reductions in
16 energy resources due to power contracts expiring without extension or
17 renewal. Several potential key changes include the following:

- 18 • 2023 - Blue Lake Units 1-4 cease operation (153 MW)
- 19 • 2025 - Manitoba Hydro PPAs expire (850 MW)
- 20 • 2026 - Cottage Grove combined-cycle PPA expires (262 MW)
- 21 • 2027 - Mankato I combined-cycle contract expires (357 MW)

22

23 Further, in the 2030-2035 timeframe, the Company faces the potential
24 retirement of three baseload nuclear units, along with Sherco Units 1 and 2
25 retiring after a 60 year operating life. Altogether this suggests that a significant
26 proportion of our baseload generation may be retired within 15 to 20 years.
27 These five generating units have been the backbone of the NSP System for

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1 many years and have formed the foundation to provide reliable service to our
2 customers. All of these retirements and contract expirations suggest that
3 having additional advantageously-priced combined-cycle capacity is a
4 reasonable choice for our system.

5
6 Q. YOU MENTIONED THAT ONE OR BOTH OF SHERCO UNITS 1 AND 2 WILL
7 POSSIBLY BE RETIRED DURING THE 2015-2030 PLANNING PERIOD. HOW DOES
8 THE AVAILABILITY OF THE MANKATO PPA IMPACT ON THAT SCENARIO?

9 A. With respect to Sherco, there is the possibility that one or both of them may
10 be retired earlier in the planning period, and we have included modeling in our
11 2015 Resource Plan to identify system requirements in the case that occurs.
12 Some stakeholders have advocated for retiring a Sherco unit as early as 2021.
13 The addition of the Mankato PPA is a hedge against that possibility.

14
15 Q. HOW DOES THE MANKATO PPA MINIMIZE THE RISK ASSOCIATED WITH
16 EMERGING ENVIRONMENTAL REGULATIONS?

17 A. We continue to experience significant uncertainty surrounding environmental
18 regulation. The EPA's existing source greenhouse gas performance standard,
19 known as the Clean Power Plan or Section 111(d) Rules, creates significant
20 uncertainty. While, the EPA's rules will likely to face legal challenges, it is
21 likely that these rules will influence future action by states and their utilities,
22 particularly if the rule is not stayed during litigation. If the Rule is not stayed,
23 each state will draft plans and submit them to EPA by 2016 to 2018, for
24 approval by EPA one year later; compliance will begin in 2020.

25
26 While much remains unknown, I conclude that the Clean Power Plan will (1)
27 put increasing pressure on coal plants, possibly resulting in reduced utilization

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1 levels or additional retirements; (2) likely increase generation from existing and
2 new natural gas plants; and (3) push us to continue adding renewable energy
3 resources and increasing energy efficiency efforts and associated investments.
4 The addition of the Mankato PPA hedges against these likely outcomes. It
5 constitutes intermediate capacity that can step in to support the NSP System
6 due to impacts the any future environmental regulation may have on our key
7 generating facilities, including our baseload coal units at the Sherburne County
8 Generating Station and our Allen S. King Plant.

V. CAPACITY RISKS

9
10
11
12 Q: MR. POLICH TESTIFIES ABOUT CAPACITY RISKS AS ONE REASON WHY HE
13 RECOMMENDS DENYING THE ADP. WHAT ARE THE CAPACITY RISKS YOU SEE
14 WITH THE MANKATO PPA BEING APPROVED OR NOT BEING APPROVED BY
15 THE COMMISSION?

16 A. Mr. Polich concludes that approving the Mankato PPA creates the risk of
17 excess capacity on the system. He does not focus on the risks inherent in the
18 Commission not granting the ADP. This section of my Rebuttal Testimony
19 addresses those risks. The risks of not granting the ADP for the Mankato
20 PPA include:
21

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1 1. Miss out on locking in a low cost combined-cycle capacity resource
2 now, recognizing that there a no costs to NSP customers until June
3 2019 and exposing NSP customers to higher cost capacity if we wait
4 until 2024 to obtain new capacity.

5 2. Rejection of the Mankato PPA could result in this capacity not being
6 available to North Dakota customers and exposing North Dakota
7 customers to higher cost capacity in 2024 which could even be a
8 much smaller (50 MW) dedicated gas generation unit or other
9 purchases which could have substantially higher costs than those of
10 the Mankato PPA.

11 3. The Mankato PPA has low operating costs and provides substantial
12 power supply management benefits.

13
14 Q: ARE THERE TECHNOLOGY RISKS ASSOCIATED WITH APPROVING THE PPA AT
15 THIS TIME?

16 A: There are several capacity risks including the risk of gas generation equipment
17 dramatically increasing in cost. This is a real possibility – we have projected
18 that costs of natural gas power generation equipment will rise due to increased
19 competition from the need to replace older and/or non-economic coal and
20 gas generation that is projected to being retired in the coming decade. Such a
21 situation occurred in the early 2000s when demand for gas generation
22 equipment spiked resulting in substantial costs being charged for slots in
23 turbine manufacturing queues. There is a real chance that this could happen
24 again in the near future with significant amounts of expected coal unit
25 retirements arising from increased environmental regulation as well as
26 economic and age-related factors.

27

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1 Q. CAN YOU GIVE AN EXAMPLE OF THE TYPES OF COSTS THAT COULD
2 CONTRIBUTE TO THE INCREASE OF COMBINED-CYCLE CAPACITY IN THE
3 FUTURE?

4 A. Yes. A contributing factor to project cost is the price of steel. Currently, the
5 price of steel has reached a new 10 year low at \$472 per ton. But, that will
6 likely change, as shown by Figure 4 which shows a historical and forecasted
7 per ton steel prices for 2010 through 2019. With steel being an important
8 component of a gas generation project, the significant cost increase would be
9 reflected in higher project costs if the Company decided to wait.

10

11 **Figure 4: 2010-2019 Steel Prices (US\$/ton)**



12

13

Source: EIU Economic and Commodity Forecast, July 2015

14

15

Given this information, it seems prudent and in the best interests of NSP
16 customers to lock into the competitively priced Mankato PPA now to avoid
17 higher future PPA and project prices due to dramatic forecasted increase in
18 steel prices over the next four years. If the average annual increase of about 9
19 percent per year over the 2015-2019 period continues into the future, by 2024

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1 steel prices would be \$985 per ton, a 109 percent increase in price from 2015
2 steel price level.

3

4

VI. CONCLUSION

5

6 Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

7 A. While the Company appreciates Mr. Polich’s analysis and opinions, we believe
8 that, on balance, proceeding with the Mankato PPA in 2019 is a reasonable
9 and prudent resource choice. While this capacity addition falls somewhat
10 before our need, the balance of factors described in my testimony support
11 including this resource in our supply portfolio.

12

13 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

14 A. Yes, it does.

15

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1 SCHEDULE A

2

3 **Table A1: Levelized Cost Analysis--\$/MWh**

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11 **TRADE SECRET ENDS]**

12 To provide greater transparency, the same information as shown in Table A1
13 is shown below in Table A2 with the costs and savings itemized in detail.

14

15 **Table A2: Detailed Breakout of Levelized Cost Analysis--\$/MWh**

16 **[TRADE SECRET BEGINS**

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26 **TRADE SECRET ENDS]**

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1 **Table A3: NSP Ratepayer Cost Impacts of Mankato PPA (ND Assumptions)**

	NET RATE COST/(SAVINGS)				
	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
Impact of Mankato PPA (\$/MWh)	(\$0.13)	\$0.14	\$0.34	\$0.25	\$0.18
Fall 2014 Sales Forecast, MWh	42,708,090	42,860,052	42,822,135	43,003,977	42,974,865
Annual Cost/(Savings) of Mankato PPA	(\$5,762,193)	\$5,910,569	\$14,493,239	\$10,856,273	\$7,948,317
Total 2019-2023 Cost/(Savings)					\$33,446,204

2

3

4 **Table A4: NSP Ratepayer Cost Impacts of Mankato PPA (Without Surplus
5 Capacity Credit)**

	NET RATE COST/(SAVINGS)				
	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>
Impact of Mankato PPA (\$/MWh)	\$0.27	\$0.55	\$0.56	\$0.56	\$0.55
Fall 2014 Sales Forecast, MWh	42,708,090	42,860,052	42,822,135	43,003,977	42,974,865
Annual Cost/(Savings) of Mankato PPA	\$11,370,026	\$23,442,769	\$23,785,133	\$24,145,523	\$23,580,054
Total 2019-2023 Cost/(Savings)					\$106,323,505

6

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1 **Table A5: ND Ratepayer Cost Impacts of Mankato PPA (ND Assumptions)**

2 **[TRADE SECRET BEGINS**

7 **TRADE SECRET ENDS]**

9 **Table A6: NSP Ratepayer Cost Impacts of Mankato PPA (Without Surplus
Capacity Credit)**

11 **[TRADE SECRET BEGINS**

17 **TRADE SECRET ENDS]**

19 **Table A7: Annual Rate Impact**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CALPINE - ND Assumptions											
Base Rates	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.041e/kWh	0.070e/kWh	0.071e/kWh	0.072e/kWh	0.073e/kWh	0.073e/kWh	0.074e/kWh
Fuel Clause	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.029e/kWh	0.060e/kWh	0.069e/kWh	0.061e/kWh	0.053e/kWh	0.047e/kWh	0.052e/kWh
Avoided Fuel & Purchased Power	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	-0.083e/kWh	-0.117e/kWh	-0.106e/kWh	-0.108e/kWh	-0.107e/kWh	-0.103e/kWh	-0.108e/kWh
Net Rate Impact	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	(0.013e/kWh)	0.014e/kWh	0.034e/kWh	0.025e/kWh	0.018e/kWh	0.018e/kWh	0.018e/kWh
CALPINE - Re-Priced											
Base Rates	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.041e/kWh	0.070e/kWh	0.071e/kWh	0.072e/kWh	0.073e/kWh	0.073e/kWh	0.074e/kWh
Fuel Clause	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.029e/kWh	0.060e/kWh	0.069e/kWh	0.061e/kWh	0.053e/kWh	0.047e/kWh	0.052e/kWh
Avoided Fuel & Purchased Power	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	-0.043e/kWh	-0.076e/kWh	-0.085e/kWh	-0.077e/kWh	-0.071e/kWh	-0.093e/kWh	-0.134e/kWh
Net Rate Impact	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.000e/kWh	0.027e/kWh	0.055e/kWh	0.056e/kWh	0.056e/kWh	0.055e/kWh	0.028e/kWh	(0.008e/kWh)

