

Rebuttal Testimony and Schedule
Kurtis J. Haeger

Before the North Dakota Public Service Commission
State of North Dakota

IN THE MATTER OF THE NORTHERN STATES POWER COMPANY ADVANCE
DETERMINATION OF PRUDENCE – AURORA SOLAR APPLICATION

Case No. PU-15-95

Resource Planning Policy Testimony

July 13, 2015

TABLE OF CONTENTS

I.	Introduction and Summary	1
II.	Resource Planning Considerations	3
III.	Prudence of Geronimo PPA	7
IV.	Impact to NSP System	11
V.	Conclusion	12

Schedules

Rebuttal Testimony of Kurtis J. Haeger (without Attachments) in the 187 MW Portfolio Proceeding, April 17, 2015	Schedule 1
---	------------

1 **I. INTRODUCTION AND SUMMARY**

2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

Q. PLEASE STATE YOUR NAME AND TITLE.

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

Q. HAVE YOU PROVIDED OTHER TESTIMONY ON THE TOPICS YOU DISCUSS HERE?

A. Yes. On February 13, 2015, I submitted prefiled written Direct Testimony in this proceeding. In that Testimony, I presented the resource planning policy issues related to the Company’s request for an Advance Determination of Prudence (ADP) for the 100 MW (nameplate) Geronimo Solar power purchase agreement (Geronimo PPA). I specifically addressed:

- Our determination of need for the project, including the impacts of demand forecast variability on our planning to meet our customers’ resource needs;
- The impact of the proposed resource acquisition on the “Restack” concept contemplated in the Settlement Agreement in Case No. PU-12-813.

I also provided testimony in the proceeding regarding our request for an ADP regarding our 187 MW Solar Portfolio (Case No. PU-15-810). However, that solar portfolio related to our need to satisfy Minnesota Solar Energy Standards, whereas the Geronimo resource is primarily related to satisfying an identified energy and capacity need to serve customers and

1 planning conservatively for customer demand needs. The impact of MISO
2 is addressed in both dockets. A truncated version of my Rebuttal Testimony
3 in the 187 MW Solar Portfolio Case is attached to this Testimony as
4 Schedule 1 (without the additional testimony attachments).

5
6 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

7 A. I respond to several issues raised in the Direct Testimony of Commission
8 Advocacy Staff member Mike Diller. Mr. Diller provides an important
9 policy perspective on the appropriate timing and scope of resource additions
10 to our System. While I agree with Mr. Diller that there are important
11 questions and potential uncertainty around future demand, my Rebuttal
12 Testimony provides information regarding a balancing of considerations that
13 we believe the Commission should take into account when reviewing the
14 Geronimo PPA.

15
16 In particular, my Rebuttal Testimony addresses:

- 17 • Some of the resource planning considerations Mr. Diller raises;
- 18 • Why the Geronimo PPA is a prudent resource addition in the context
19 of our resource planning needs and diverging public policy choices in
20 the states we serve; and
- 21 • The anticipated impact to the NSP System if the Commission should
22 conclude that the Geronimo PPA is not in North Dakota customers'
23 best interests.

24

1 Q. PLEASE SUMMARIZE WHY THE GERONIMO PPA IS PRUDENT FROM A
2 RESOURCE PLANNING PERSPECTIVE.

3 A. We believe the Geronimo Solar PPA provides valuable capacity and energy
4 to our System that will be utilized to serve our customers over the next 20
5 years. As the product of a competitive resource acquisition process, the
6 Geronimo PPA will also help diversify our generation fleet, provide
7 flexibility as we look ahead to the potential retirement of aging resources,
8 and help us meet existing and potentially emerging state and federal
9 requirements.

10

11 **II. RESOURCE PLANNING CONSIDERATIONS**

12

13 Q. MR. DILLER SUGGESTS THAT THE GERONIMO SOLAR PPA IS “NOT NEEDED”
14 BECAUSE THE COMPANY HAS ADEQUATE RESOURCES TO MEET PEAK
15 DEMAND UNDER ITS CURRENT FORECAST. HOW DO YOU RESPOND?

16 A. I agree that assessing and planning for peak demand is one appropriate
17 consideration, but it is not the exclusive criterion in our decision to add
18 resources to the System. I also acknowledge that our most recent review of
19 our loads and resource balance suggests the Company likely has sufficient
20 peaking resources through 2023 based on the development of all of the
21 Company’s proposed resource additions. That being said, the Company
22 must consider more than just our peak design day resource needs when
23 selecting resources and consider both the need to serve our customers under
24 all reasonable circumstances and the overall energy mix for our integrated
25 System. In addition, forecasts are inherently subject to change. As a result,
26 in planning resource additions, we take into account (1) peak loads, (2)
27 reserve margin requirements, (3) contingencies such as higher-than-

1 anticipated peak demand or forced (unplanned) outages, (4) energy mix, and
2 (5) relevant policy considerations.

3
4 Q. MR. DILLER ALSO SUGGESTS THAT IN THE COMPETITIVE RESOURCE
5 ACQUISITION PROCESS (CAP) DOCKET BEFORE THE MINNESOTA
6 COMMISSION, THE COMPANY INDICATED “THAT GENERATION SURPLUS
7 EXISTS THROUGH 2023.”¹ IS THIS ACCURATE?

8 A. It is correct that we pointed to our recent September 2014 forecast as an
9 indicator of a capacity surplus on our integrated System through 2018 and
10 possibly 2023. However, we also noted that the existence of a surplus
11 through 2023 “increasingly depends on aging peaking generation.” We
12 further recognized that other regulatory bodies in that docket suggested that
13 capacity should be added to the System in 2018.

14
15 Ultimately, the Minnesota Commission concluded that “[n]eed assessments
16 are necessarily approximate and even the most analytic utilities must plan for
17 a range of outcomes and the [Minnesota] Commission will err on the side of
18 ensuring that Xcel has enough capacity to meet the needs of its customers.”²
19 Consequently, we have undertaken the Geronimo PPA and are bringing it
20 before the Commission for approval in North Dakota.

21
22 While we recognize that the Minnesota and North Dakota Commissions
23 may reach different conclusions regarding the needs of the System and the
24 best way to plan for the future, the Geronimo PPA will provide immediate
25 energy benefits and long-term capacity benefits. Later in my testimony, I

¹ M. Diller Direct Testimony at 2:22-24 (citing NSP’s MN Reply Comments at p. 6, MPUC Docket Nos. E002/M-14-789 and E002/CN-12-1240 (Nov. 3, 2014)).

² *Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms with Xcel* at 9, MPUC Docket Nos. E002/M-14-789 and E002/CN-12-1240 (Feb. 5, 2015) (CAP Order).

1 discuss the impacts that a divergent view between the North Dakota and
2 Minnesota Commissions may have on the development of future resource
3 additions and on the development and operation of the integrated NSP
4 System.

5
6 Q. MR. DILLER COMPARES NSP'S MOST RECENT PEAK LOAD FORECASTS WITH
7 EXISTING GENERATION CAPACITY TO ILLUSTRATE THAT THE COMPANY WILL
8 HAVE SUFFICIENT CAPACITY UNTIL 2024. ASSUMING FOR THE MOMENT THAT
9 PEAK DEMAND SHOULD BE DETERMINATIVE, HOW DO YOU RESPOND?

10 A. Mr. Diller points to Table 6 in our Application at page 36, which illustrates
11 our 2015 System Capacity Forecast through 2024, to make this point. I
12 concur that this information reasonably demonstrates Mr. Diller's point
13 based on peak demand forecasts.

14
15 However, I note that Table 6 also illustrates that from 2015 through 2018
16 our 2015 Forecast shows only a 1 to 2.5 percent surplus and virtually no
17 excess capacity in 2019 and 2021. Further, Table 7 to our Application shows
18 that on a North Dakota allocated basis, there is no excess capacity in 2019
19 and 2020.

20
21 As discussed in our Application, under these narrow ranges a small error in
22 our customer load forecasts could move us from a surplus/no deficit
23 position to a material capacity shortfall. In recent years, normal forecast
24 variability has resulted in demand swings of 200 MW (2 percent) or more.
25 Consequently, there are prudent reasons to add the capacity and energy
26 provided by the CAP portfolio of resources even though we are not
27 currently forecasting a capacity deficit.

1 Q. DOES THE POTENTIAL FOR CHANGES IN EXISTING COMPANY GENERATION
2 RESOURCES ALSO AFFECT THE NEED FOR THE GERONIMO PPA?

3 A. Yes. We are proposing to add the Geronimo Solar PPA when a significant
4 quantity of our existing resources will be in question. We recognize that
5 given this Commission's preference for low-cost resources, the Commission
6 may prefer maintaining existing coal generation to renewable additions.
7 However, the NSP System may need to replace more than 75 percent of its
8 energy resources by 2035 for a variety of reasons. In particular, our Sherco
9 Units 1 and 2 units are aging and cannot operate indefinitely without
10 investing significant capital. As discussed in our Resource Plan in Case No.
11 PU-15-019, long lead times mean we must build flexibility and advance
12 planning into our consideration of future circumstances. As a result, even if
13 our demand forecast is accurate and remains unchanged, we still must add
14 cost-effective resources and make investments in our System to ensure
15 adequate capacity for our customers.

16

17 Q. HOW DOES THE GERONIMO SOLAR PPA HELP TO BALANCE THE VARIABLES
18 THAT AFFECT THE NEED FOR THE PROJECT?

19 A. The timing, size, and type of the project each help balance our System to
20 meet the needs of our customers. By adding 100 MW of solar in the 2016-
21 2018 timeframe (2016 in-service; 2018 MISO accreditation), we can diversify
22 our fleet through this resource addition, and do so at a time when other
23 generation in our portfolio may be facing significant changes due to age and
24 federal or state policy mandates. This approach helps ensure we can reliably
25 serve our customers even if demand levels change.

26

1 Even if our demand forecast does not change, the Geronimo PPA helps
2 provide us with the flexibility to manage our generation fleet as industry
3 circumstances and markets change. It will further be used because the output
4 of the Geronimo PPA will displace other energy on our System. For these
5 reasons, I disagree with Mr. Diller's suggestion that the project will not be
6 useful and instead believe this resource addition is prudent, used, and useful
7 for our customers.

8
9 **III. PRUDENCE OF GERONIMO PPA**

10
11 Q. SHOULD THE COMMISSION VIEW THE GERONIMO PPA RESOURCE ADDITION
12 DIFFERENTLY THAN IT VIEWED THE COMPANY'S PROPOSED 187 MW SOLAR
13 PORTFOLIO IN CASE NO. PU-14-810?

14 A. Yes, it is somewhat different. The Company is undertaking the Geronimo
15 PPA resource addition, as well as the Calpine Mankato PPA and the Black
16 Dog 6 resources, approved in Case No. PU-13-94, to meet a previously
17 identified need in the 2017-2019 timeframe. The 187 MW solar portfolio,
18 on the other hand, had a more specific purpose of helping the Company
19 comply with Minnesota's Solar Energy Standard.

20
21 While it is also true that the Geronimo PPA will count toward our
22 compliance with Minnesota's 10 percent by 2030 solar energy goal, the
23 Geronimo PPA was the product of a regulatory process focused on
24 determining how to meet a capacity need and its selection was not related
25 directly to a specific solar resource need. As such, it serves a dual purpose.

1 Q. WHY SHOULD THE COMMISSION CONSIDER ADDITIONAL QUALITATIVE
2 BENEFITS OF THIS PROJECT?

3 A. As we discuss in our recently filed resource plan, the utility industry and the
4 NSP System are in a period of significant change and uncertainty. We
5 believe that our resource decisions during this time should be made with an
6 eye to the future. The fuel price hedge and resource diversity value of the
7 Geronimo PPA are some of the types of considerations that the
8 Commission should take into account while evaluating our request. The
9 Commission has been making these types of qualitative evaluations since at
10 least 2008³ and should continue to do so.

11
12 In addition, solar is a developing resource and making utility scale additions
13 to the NSP System will provide us with operational experience with this type
14 of resource. Further, solar resources provide us with a hedge against other
15 fuels, adding to our resource diversity. These resource additions will also
16 help to position us should future carbon regulations in fact become
17 mandatory.

18
19 These qualitative factors are the same types of factors that the Commission
20 has, in the past, used to recognize the prudence of renewable resource
21 additions that were not least cost (but were a reasonable cost for that
22 resource type) and not utilized to meet an identified capacity deficit.⁴ Given
23 the uncertain future, we believe it is important to incorporate qualitative
24 factors that are likely to increase future costs into the Commission's
25 preference for least cost resources.

³ See Case Nos. PU-06-481; PU-06-482.

⁴ See, e.g. Case No. PU-08-907.

1 Q. MR. DILLER SUGGESTS THAT DESPITE EXISTING TAX INCENTIVES, SOLAR
2 ENERGY COULD BECOME LESS EXPENSIVE IF THE COMPANY SIMPLY WAITED
3 TO ADD SOLAR RESOURCES AT A LATER DATE. WHAT IS YOUR RESPONSE?

4 A. I agree with Mr. Diller that as solar technology matures, its prices are likely
5 to drop. This is consistent with current industry literature and our
6 experience with wind. That said, there is significant value for the Company
7 to obtain experience with solar as a capacity resource now so that we are
8 able to utilize it more effectively as the price of solar drops and it becomes a
9 more mainstream resource. This is also consistent with our approach to
10 wind, where we made significant investments as the technology was
11 maturing and are now in a better position to take advantage of historically
12 low pricing for wind energy.

13
14 Further, the pricing impact of the federal Investment Tax Credit (ITC) helps
15 make the Geronimo PPA an attractive resource even at a higher price than
16 other capacity resources we are adding. One of the advantages of solar
17 generation is that it generally generates the most electricity during the peak
18 times of the day. Gaining experience with solar as a capacity resource will
19 allow us to better understand the impacts of this on-peak resource on our
20 operations and planning. The effect of such resources on the remainder of
21 our System is an important operational experience for us moving forward.

22
23 Finally, the Geronimo PPA is structured as several direct interconnections to
24 our distribution system. Having experience with an energy and capacity
25 resource that resides on the distribution system is also worthwhile for us. As
26 solar matures, we expect it to be a significant distribution resource and
27 gaining experience now will serve us well into the future.

1 Overall, the pricing impacts of the ITC help us gain this experience at
2 reasonable pricing. While solar may come down in price into the future, we
3 believe that gaining this experience now at prices we are able to realize
4 through the ITC is a prudent way to move forward.

5
6 Q. HOW DO YOU BELIEVE THE PRICE OF THE GERONIMO PPA SHOULD FACTOR
7 INTO CONSIDERATION OF THE PRUDENCE OF THIS RESOURCE ADDITION?

8 A. We recognize that any price impact on customers needs to be considered
9 carefully, and believe that the Geronimo PPA provides useful capacity and
10 energy for a small additional cost. As Company witness Mr. Paul B. Johnson
11 discusses in his Direct Testimony, our Strategist dispatch simulation
12 forecasts that for most years the rate impact of the Geronimo Solar Project
13 will be largely offset by decreases in the cost of fossil fuel and other
14 purchased energy. Further, the initial rate impact in 2017 is expected to be
15 approximately 0.016¢ per kWh, or about 12¢ per month for a customer using
16 750 kWh, and stay relatively flat at that level through 2024.

17
18 In light of these facts, we believe the cost of the project presents a
19 reasonable investment level for the capacity and energy we will receive.

20
21 Q. IN SUMMARY, WHY IS THE GERONIMO SOLAR PPA A PRUDENT RESOURCE
22 ADDITION AT THIS TIME?

23 A. The Geronimo PPA is the product of a resource acquisition process with the
24 specific purpose of helping to meet an identified need of 150-500 MW in the
25 2017-2019 timeframe. It provides system flexibility as we consider the
26 future of aging plants in our fleet, and it supports long-term objectives for
27 our System. The Geronimo resource provides the further benefits of fuel

1 diversity and hedging against the need to acquire substantial renewable
2 resources in short timeframes to satisfy emerging federal mandates. Each of
3 these benefits is provided at a reasonable cost and low overall rate impact.
4

5 For these reasons, we respectfully request the Commission's advance
6 determination of prudence.
7

8 **IV. IMPACT TO NSP SYSTEM**

9

10 Q. DOES POTENTIAL VALUE OF THE GERONIMO PPA AS A CAPACITY RESOURCE
11 ON THE NSP SYSTEM AFFECT THE COMPANY'S USE OF ITS CAPACITY AND
12 ENERGY SHOULD THE COMMISSION DENY THE REQUESTED ADP?

13 A. It may. To the extent the Commission chooses not to have our North
14 Dakota customers participate in this resource, we will need to determine
15 whether it would be appropriate to allocate North Dakota's share of the
16 capacity and energy to our North Dakota customers or utilize the capacity
17 and energy in a different manner. Should the capacity from this resource not
18 be allocated to our North Dakota customers, this could result in our need to
19 analyze and plan for our North Dakota customers on a separate basis from
20 the remainder of the integrated NSP System. I discuss how this would work
21 further in the attached testimony from the 187 MW Solar Case.
22

23 Additionally, should the energy generated by this solar resource prove
24 valuable to other jurisdictions or third parties, we believe it reasonable to
25 allocate the renewable energy (and not just the accompanying solar RECs) to
26 those parties or jurisdictions who value it most. In the event that were to

1 occur, we would propose to serve our North Dakota customers with market
2 energy in lieu of the energy provided by the Geronimo PPA.

3

4

V. CONCLUSION

5

6 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

7 A. Yes, it does.

8

Rebuttal Testimony and Schedules
Kurtis J. Haeger

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company for an
Advance Determination of Prudence for a 187 MW Portfolio of Utility Scale Solar
Resources

Case No. PU-14-810
Exhibit___(KJH-2)

Rebuttal Testimony

April 17, 2015

TABLE OF CONTENTS

I.	Introduction and Summary	1
II.	Resource Planning Overview	3
III.	Reliance on MISO	9
IV.	Prudence of Resource Additions	20
V.	Policy Considerations	22
VI.	Changes to PPAs	36

Schedules

Direct Testimony of Kurtis J. Haeger in the Geronimo Solar PPA Proceeding, Feb. 13, 2015	Schedule 1
Letter Agreements Between the Company and the PPA Developers	Schedule 2

I. INTRODUCTION AND SUMMARY

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

Q. PLEASE STATE YOUR NAME AND TITLE.

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

Q. HAVE YOU PROVIDED OTHER TESTIMONY ON THE TOPICS YOU ARE PROVIDING HERE?

A. Yes. On November 7, 2014, I submitted prefiled written Direct Testimony in this proceeding. That testimony provided the Commission with the Company’s view of the resource planning context that supports granting an Advance Determination of Prudence (ADP) for this requested 187 MW solar portfolio resource addition.

I also submitted prefiled written Direct Testimony on February 13, 2015 in Case No. PU-15-095 (the Geronimo Solar PPA proceeding). My testimony in the Geronimo Solar PPA proceeding provides additional information about the Company’s resource planning efforts and describes NSP’s views on the desirability to plan conservatively to ensure sufficient generating capacity is and reasonable-cost energy in place to meet our customers’ needs under all reasonable circumstances. In addition, that testimony provides discussion about the generation resource “Restack” concept, which arose in our settlement of the last rate case (Case No. PU-12-813) and which is currently being negotiated by the Company and Commission Staff.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

Many of the issues addressed in my Direct Testimony in the Geronimo Solar PPA case are similar to the issues raised in this case. As a result, I have attached a copy of the public version my Direct Testimony (without Schedules) in that case as, Schedule 1 to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the Direct Testimony of Commission Advocacy Staff member Mike Diller. Mr. Diller provides an important and valid perspective for the Commission to consider in planning for system additions in a multi-jurisdictional utility like the Company. Mr. Diller's testimony is helpful in that it provides a reasoned policy perspective on the timing and justification for the Company's resource additions to serve our North Dakota customers. However, that policy perspective carries with it certain implications and risks that should also be taken into account as the Commission considers the appropriate timing for adding resources under the circumstances.

My Rebuttal Testimony provides the Company's perspective on the issues raised by Mr. Diller. More specifically, I address the following:

- General resource planning concepts that influence the selection and timing of resource additions;
- The development and utilization of a planning reserve margin;
- The risks associated with reliance upon MISO as a backstop in the event of a capacity shortfall;
- The Company's need for additional resources at this time in light of current demand forecasts;
- The potential impact on NSP's integrated system arising from differing

- 1 public policy choices in the states we serve; and
- 2 • The implications if North Dakota chooses to have capacity direct-
- 3 assigned to the jurisdiction rather than accept a pro-rata allocated share
- 4 of the Company's integrated generation fleet.

5

6 My testimony also presents letter agreements for minor changes to the PPAs

7 for the 187 MW solar portfolio.

8

9 Q. MR. DILLER SUMMARIZES HIS TESTIMONY WITH THE FOLLOWING CONCLUSION

10 (PAGE 1:20-26):

11 "NSP's North Dakota ratepayers do not need the proposed SP for

12 generation capacity or the energy that these units would provide. The

13 proposal does not represent least cost planning. Instead, the SP is being

14 proposed to satisfy Minnesota's Solar Energy Standard (SES). Staff

15 recommends that the NDPSC deny the requested ADP and also deny

16 any replacement costs for the denied capacity." (Emphasis added.)

17

18 HOW DO YOU RESPOND?

19 A. Mr. Diller's summary touches on four important policy issues that I will

20 address below. They are: (1) the timing and cost of generation additions to

21 meet customer needs, (2) the relevant considerations and criteria (including

22 least-cost planning principles) in selecting resources, (3) divergent state

23 policies and the implications of those policies on a multi-state system, and (4)

24 the implications and risks of direct-assigning generation to North Dakota.

25

26 **II. RESOURCE PLANNING OVERVIEW**

27

28 Q. WHY ARE YOU PROVIDING AN OVERVIEW OF RESOURCE PLANNING IN YOUR

29 TESTIMONY?

30 A. Mr. Diller's Direct Testimony raises important issues that are central to

1 integrated resource planning and the Company's obligation to provide safe,
2 reliable and adequate service to our customers under all reasonable
3 circumstances. I think it is important for the Company to provide
4 background and context on these issues to assist the Commission in
5 considering the policy implications of Mr. Diller's proposed approach.

6

7 Q. PLEASE SUMMARIZE HOW THE COMPANY PLANS TO MEET ITS OBLIGATIONS.

8 A. Public utilities such as the Company have an obligation to serve all of the
9 needs of all customers in their service areas. This obligation to serve requires
10 that we provide for our customers' electric needs under all reasonable
11 circumstances.

12

13 The obligation to serve leads to the utility planning its system to ensure
14 sufficient generating capacity is available to meet customer requirements. In
15 order to avoid the risk of falling short, we must plan for a future that has
16 many unknowns. Realizing that new generation usually takes several years to
17 develop – including planning and design, obtaining regulatory approvals,
18 procuring transmission access and fuel supply, and of course the actual,
19 physical construction – utilities generally must initiate the generation
20 development process three to six years before the resource is needed. The
21 future can look very different from what we expect today. The need to
22 accommodate future uncertainties requires a utility to plan conservatively and
23 ensure that adequate power supply exists even if unforeseen circumstances
24 arise.

25

26 Q. WHAT DETERMINES WHETHER THE COMPANY NEEDS TO ADD GENERATION?

1 The Company has two major objectives when it considers whether to add new
2 resources to the integrated system:

- 3 • Reliably serve customers during those hours when their needs are
4 highest; and
- 5 • Minimize total system energy costs throughout the year, taking into
6 account all relevant considerations.

7
8 To meet these twin goals, the Company considers both the need to meet our
9 peak demand and our overall energy mix. There is more than one
10 combination of resource types that can be employed to meet a given system's
11 peak demand. And there is a variety of energy sources that can contribute to
12 our mix.

13

14 Q. IS IT APPROPRIATE TO ONLY CONSIDER THE COMPANY'S CURRENT DEMAND
15 FORECASTS WHEN DECIDING WHETHER TO ADD RESOURCES TO THE SYSTEM?

16 A. I agree that assessing and planning for the current forecast of peak demand is
17 a critical consideration, but it is not the only criterion in our determination of
18 what resources to add to the system. The Company must consider both the
19 need to reliably serve our customers under all reasonable circumstances and to
20 achieve a low-cost overall energy mix for our integrated system while meeting
21 the policy requirements of all of the states we serve.

22

23 As a result, in planning resource additions, we take into account (1) peak
24 demand, (2) reserve margin requirements, (3) contingencies such as higher-
25 than-anticipated peak demand or forced (unplanned) outages, (4) energy mix
26 (and overall energy costs), and (5) relevant policy considerations.

27

1 Q. WHY DOES THE COMPANY NOT PLAN NEW GENERATION TO PRECISELY MATCH
2 FORECAST PEAK DEMAND?

3 A. The Company makes its resource investments within a long-term planning
4 horizon – 40 years or more. It is not plausible to precisely match generating
5 capacity with the exact customer demands in each year, keeping in mind that it
6 is not acceptable to be short in any one year. We take a comprehensive
7 approach to planning how we will serve all customers reliably throughout the
8 planning horizon considering all circumstances.

9

10 Q. WHAT DO YOU MEAN BY A COMPREHENSIVE APPROACH TO PLANNING?

11 A. Several variables are considered. We consider (1) the size or amount of
12 capacity to be added to the system including consideration of economies of
13 scale, (2) the type of resource selected, such as natural gas or renewable
14 resources, (3) the timing of the selection to ensure that we meet all of our
15 obligations, and (4) whether there is firm delivery from the new generation site
16 to the Company's customers.

17

18 For example, it is commonly known that the least expensive option for adding
19 capacity is to build combustion turbines to serve as peaking plants. Yet, most
20 utilities also plan for and build intermediate and baseload plants and add
21 renewable energy to their systems – even at a much higher capital cost per
22 MW than a peaking unit – to balance the energy needs of the customers they
23 must serve. Utility planners understand that baseload plants and renewable
24 energy resources are more expensive to build, but their energy production
25 costs are relatively low.

26

27 Seeking to obtain an appropriate mix of baseload, intermediate, and peaking

1 facilities helps to balance the costs of capacity and energy and obtain a diverse
2 resource mix for the utility. A diverse resource mix, in turn, allows us to meet
3 a wide range of needs from round-the-clock baseload energy to immediate
4 peaking needs. A well-balanced generation portfolio provides a versatile and
5 robust ability for a utility to respond to its customers' changing needs.

6

7 Q. WHAT ARE THE FACTORS THAT YOU CONSIDER WHEN DECIDING WHETHER
8 AND WHEN TO INSTALL NEW GENERATION SUCH AS THE 187 MW SOLAR
9 PORTFOLIO THAT IS THE SUBJECT OF THIS CASE?

10 A. First, new generation resources, including those that are the subject of this
11 proceeding, require significant investment and time to build. We make
12 generation resource decisions taking into account that we need to have
13 enough time to deploy the generation resource to meet the identified
14 customer need. This can be a challenge, since the development and
15 construction cycle take up to five or more years during which time our
16 demand forecasts could change dramatically (either up or down).

17

18 Second, economics generally favor building generation in fewer, but larger,
19 capacity increments to capture economies of scale and to minimize duplicative
20 infrastructure. This dynamic can result in choosing generation resources that
21 exceed the immediate minimum forecast demand level by some amount to
22 capture the benefits of the larger increment (*i.e.*, scale, efficiency, margins).
23 Constructing larger increments of generation will also influence the timing of
24 the next generation resource since, once built, a generation resource remains
25 available to meet increasing demand, thereby deferring the addition of the
26 next generation resource.

27

1 All of these factors tend to favor having a conservative amount of generation
2 on the system going forward than what a simple analysis of the expected
3 demand and the existing resources may suggest.

4

5 Q. DOES THE UTILITY PLAN ITS SYSTEM IN ISOLATION FROM OTHER UTILITIES?

6 A. In some ways yes, and in some ways, no.

7

8 On one end of the spectrum, a utility is ultimately responsible for ensuring
9 that they will have adequate resource to meet its customers' needs. Therefore,
10 utilities must do their own system planning, utilizing their own resource
11 planning criteria, which is influenced by their obligations and regulatory
12 oversight.

13

14 On the other end of the spectrum, planning paradigms have always taken into
15 account the efficiencies achieved through interconnected operations with
16 other interconnected utility systems. For example, when the Company was a
17 member of the Mid-Continent Area Power Pool (MAPP), the ability to utilize
18 other systems to ensure adequate capacity, and the MAPP requirements in this
19 respect, were a key part of our resource planning considerations. Similarly,
20 with the advent of MISO, the MISO reserve margin requirements are also a
21 key consideration in our resource planning. Regional coordination enables all
22 participating utility systems to meet reliability standards which lower reserve
23 margins, than if each system operated on its own.

24

25 I stress, however, that the existence of other systems to support our resource
26 adequacy does not fully compensate for the need to ensure we have sufficient
27 capacity available on our system to meet our customers' needs. While regional

1 constructs, such as MISO, can be helpful, I do not believe it is prudent to rely
2 on MISO to ensure adequate resources are available should conditions change.

3

4

III. RELIANCE ON MISO

5

6 Q. MR. DILLER TESTIFIES ON PAGE 3:8-14:

7 “The structure of generation resource adequacy has changed under
8 regional grid operators like the one NSP belongs to; Midcontinent
9 Independent System Operator (MISO). One of the primary values of
10 operating the electric system on a regional basis is to share generation
11 assets to enable companies to carry a smaller reserve margin and
12 improve reliability at the same time. It is no longer necessary or
13 desirable for every utility to carry large amounts of excess generation as
14 though they are still operated on a stand-alone basis.”

15

16 HOW DO YOU RESPOND?

17 A. Mr. Diller is correct that regional operation such as under MISO may enable
18 utility systems to carry smaller reserve margins than if they each operated on
19 their own. He is also correct that MISO recently began operating a voluntary
20 capacity auction that provides a small amount of short-term capacity to
21 utilities for balancing their systems.

22

23 That said, I have some concerns with Mr. Diller’s conclusion. Specifically, his
24 position with respect to MISO does not fully consider all of the factors that
25 must be taken into account when planning for future resource additions.
26 These concerns relate mainly to MISO’s resource adequacy requirements and
27 the related planning reserve margin as well as the feasibility of relying on
28 MISO’s voluntary capacity auction. Fundamentally, we believe that
29 participation in MISO does not remove our need to ensure that we have
30 enough capacity resources for our own NSP System.

31

1 **A. MISO Resource Adequacy Requirements**

2 Q. WHAT IS THE PURPOSE OF A PLANNING RESERVE MARGIN WITH RESPECT TO
3 RESOURCE ADEQUACY?

4 A. The planning reserve margin represents additional generation capacity, over
5 and above the utility's forecast of its customers' demand needs. Thus, the
6 planning reserve margin is forward looking and based on the utility's
7 forecasted demand. To illustrate, if a utility has 100 MW of forecasted
8 demand and it requires 7 percent of reserve margin, it must have 107 MW of
9 capacity.

10

11 The excess capacity required by the reserve margin is intended to
12 accommodate operational fluctuations that occur throughout the year. In
13 essence, the reserve margin is intended to ensure sufficient capacity is available
14 to account for variations in the actual levels of demand as well as resource
15 availability on peak days, as compared to the levels assumed in the forecast
16 modeling. In this way, the reserve margin ensures that capacity is available to
17 address the fundamental difference between forecasting and actual operations.

18

19 For example, our demand forecasts are weather normalized and so the reserve
20 margin accounts for the actual variations in weather that we know will occur.
21 As another example, our forecasts assume that our generating resources will
22 be operating under normal conditions; the reserve margin provides a cushion
23 for outages and derates that can affect the actual amount of generation
24 available on any given day.

25

26 However, our demand forecasts are also keyed off of key economic indicators
27 and other, non-operational, assumptions to determine our forecasted amount

1 of customer demand. For example, we utilize econometric data such as
2 housing starts and gross domestic product in building our demand forecasts.
3 We also make assumptions about customer usage patterns and technological
4 factors than can impact customer demand. Since the reserve margin does not
5 take into account these non-operational factors and therefore is not designed
6 to compensate for changes to these factors, should these non-operational
7 assumptions prove to be incorrect, it is likely the reserve margin will not be
8 sufficient to ensure that sufficient capacity is available to meet customer
9 demand.

10
11 As described in my testimony in Case No. PU-15-095 (provided as Schedule
12 1), the Company has seen a fluctuation in its demand forecasts due to these
13 non-operational metrics that argue for conservative resource planning
14 notwithstanding the availability of a reserve margin.

15
16 Q. DOES THIS MEAN THAT YOU DO NOT AGREE THAT THE COMPANY SHOULD
17 ONLY PLAN TO MEET ITS DEMAND FORECAST PLUS A RESERVE MARGIN?

18 A. Correct. The planning reserve margin has limits; it does not take into account
19 that demand forecasts can shift dramatically in the four to six year period that
20 it may take to develop or arrange for additional generation resources.
21 Economic factors and historical usage are two of the more significant forecast
22 variables, and the uncertainty in these variables since the 2008/2009 recession
23 has been significant.

24
25 That is why we believe it is appropriate to take a conservative approach in
26 resource planning by accounting for these variables that are not adequately
27 captured by a planning reserve margin.

1

2 Q. DO YOU CONCUR WITH MR. DILLER THAT MISO'S PLANNING RESERVE
3 MARGIN REQUIREMENTS ARE LIKELY TO DECLINE IN THE FUTURE?

4 A. It's difficult to say what the future holds for MISO's reserve margin
5 requirements. MISO's reserve margin calculations are based on a series of
6 assumptions. Under a certain set of assumptions, MISO forecasts that the
7 current 7.1 percent planning reserve margin could decline to 6.6 percent in
8 2024. However, this result reflects assumptions that there will be significantly
9 more generation added to the MISO system by 2024 and that these future
10 resources will be more reliable than existing generation. However, given the
11 uncertainty surrounding the utility industry and changes in generation
12 technology, MISO concluded that a more likely outcome is that the reserve
13 margin will stay relatively flat.

14

15 When we couple the changing industry with the potential of retiring a
16 significant number of large baseload plants in the next several years, it is clear
17 that the future need for new generation is very difficult to predict. It is my
18 opinion that this uncertainty argues for a more conservative planning
19 approach now.

20

21 **B. MISO Voluntary Capacity Auction**

22 Q. DO UTILITIES BUY AND SELL CAPACITY WITH EACH OTHER TO BALANCE THEIR
23 NEEDS?

24 A. Yes. Historically, utilities have used bilateral agreements to buy and sell both
25 short-term and long-term capacity and energy to each other. In addition to
26 the traditional option of bilateral agreements, MISO has developed a
27 voluntary short-term capacity auction as an option for utilities to use.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27

Q. DO YOU AGREE WITH MR. DILLER'S CONCLUSION THAT THE AVAILABILITY OF BALANCING CAPACITY THROUGH MISO PRECLUDES THE NEED FOR NSP TO PLAN FOR AND OBTAIN CAPACITY FOR ITS CUSTOMERS?

A. No. While MISO's efforts have been beneficial to customers, the short-term voluntary capacity auction administered by MISO is not an effective tool to replace traditional, single-system resource planning efforts. Utilities have typically accomplished the same outcome through bilateral transactions. Therefore, MISO's voluntary capacity auction merely provides another option for utilities to consider on a short-term basis only.

Q. IS IT PRUDENT FOR UTILITIES TO RELY ON MISO'S VOLUNTARY CAPACITY AUCTION TO BACKSTOP ANY RESOURCE DEFICIENCIES?

A. I do not believe so. The same factors that could contribute to a longer-term capacity deficit for a utility are likely to also lead to an absence of available capacity in the MISO voluntary capacity auction. Therefore, prudent resource planning would ensure that a utility's system has sufficient resources under all circumstances, notwithstanding the availability of a balancing mechanism such as the MISO voluntary capacity auction.

Q. PLEASE ELABORATE.

A. Fundamentally, it is only prudent to rely on MISO's voluntary capacity auction if we can be assured that sufficient capacity will be available in the MISO region when we need it. I do not believe that the current structure of MISO's voluntary capacity auction can provide such guarantees; let alone ensure that we can obtain the capacity at a reasonable price.

1 On the demand side, since a large portion of the capacity on a utility's system
2 is driven by historical usage and economic factors, there is a high probability
3 that when these key indicators change the customer demand on any one
4 utility's system, they will also be changing the demand requirements of the
5 other utilities within MISO. Thus, the capacity needed to support one utility's
6 deficiency may likely be needed to support another utility's deficiency.
7 Without a buffer of additional capacity above a utility's planning reserve
8 margin, there is no guarantee that capacity will be available when it is needed.

9

10 Q. IS THE SAME THING TRUE ON THE SUPPLY SIDE?

11 A. Yes, the same is true on the supply side. With implementation of existing
12 environmental regulations (*e.g.*, Mercury and Air Toxics Standards, Cross-State
13 Air Pollution Rule) or potentially new regulations (*e.g.*, Clean Power Plan),
14 there is a high likelihood that the economics of keeping existing power plants
15 open will be adversely impacted, which could result in retirements. These
16 retirements are likely to happen simultaneously across many utilities. The
17 potential for significant future power plant retirements within a relatively short
18 period of time could constrain available capacity when it is most needed.

19

20 Again, this uncertainty would suggest that MISO's voluntary capacity auction
21 may have use as a backstop tool only, but not as a prudent resource to rely on
22 to meet capacity needs. And relying on other utilities with excess generation
23 to meet the Company's capacity needs could lead to unforeseen capacity
24 deficiencies in the future.

25

26 **C. Other Considerations**

27 Q. MR. DILLER POINTS OUT THAT MISO HAS A VERY LARGE FOOTPRINT,

1 INCLUDES SIGNIFICANT CAPACITY, AND PROVIDES ECONOMIES OF SCALE TO
2 ITS MEMBERS. SHOULDN'T THIS HELP MITIGATE THE ISSUES YOU JUST
3 DESCRIBED?

4 A. I generally agree with Mr. Diller that MISO provides these significant benefits
5 to its members in the region. Through its roles as regional transmission
6 provider and operating the regional energy market, MISO provides valuable
7 coordination to the regional marketplace. Further, MISO's large footprint,
8 and continual transmission planning efforts to reduce congestion on the
9 MISO system, provide significant benefits to knit the MISO system together
10 and provide outlet for location-based (*i.e.*, wind) generation for the entire
11 MISO system.

12
13 However, the MISO footprint is split up into nine Local Resource Zones
14 (LRZ). The transmission connections between each LRZ may not be
15 sufficiently robust to allow for capacity to be shared amongst zones for
16 resource adequacy purposes. To account for this, MISO has included a
17 "Local Clearing Requirement" in its resource adequacy rules, which
18 determines the amount of resources which must be located in a utility's LRZ
19 so that it can meet its resource adequacy requirements.

20
21 Therefore, in reality, the Company must mainly rely (with a few exceptions)
22 on the resources available in LRZ 1, which is where the NSP System is
23 located. Having to rely on a single LRZ for capacity sharing significantly
24 mitigates the economies of scale and geographic breadth of MISO for
25 resource adequacy purposes. I note that the resource additions for which we
26 are requesting an ADP have added value because they reside within LRZ 1.

27

1 I believe Mr. Diller's assessment overstates the usefulness of MISO's
2 voluntary capacity market for resource adequacy purposes. In order for there
3 to be sufficient capacity available in the MISO voluntary capacity auction that
4 can be used for the NSP System, other utilities within LRZ 1 will need to have
5 installed sufficient excess capacity to make up any shortfall the Company may
6 have. If all utilities only planned to their reserve margin there would not be
7 significant amounts of available capacity for the Company to use. Further, as
8 the largest system in LRZ 1, the use of excess capacity provided by the fact
9 that capacity additions are "lumpy" in nature could be insufficient for the
10 Company to use.

11
12 To underscore the fact that reliance on MISO's voluntary capacity auction
13 could result in a capacity shortfall, I note that MISO's capacity auction is held
14 only about two months prior to the start of the applicable planning year. So,
15 if the auction fails to supply needed capacity, there is essentially no time
16 afterwards to correct the deficiency.

17
18 Q. MR. DILLER ACKNOWLEDGES ON PAGE 6:20-28 THAT THE COMPANY CAN
19 INCUR SIGNIFICANT PENALTIES FOR FAILURE TO PLAN FOR ADEQUATE
20 GENERATION TO COVER OUR PEAK DEMAND AND REQUIRED RESERVE
21 MARGINS. HOW WOULD YOU RESPOND?

22 A. I agree that the potential for penalties is both real and substantial. However, I
23 take issue with his apparent conclusion that it would be prudent to rely on
24 purchasing short-term capacity to cover any potential shortfall that may arise.

25
26 Ultimately, MISO is not designed or intended to supplant the utility's
27 traditional resource planning function nor the Commission's oversight and

1 approval of generation resource selections. MISO's key responsibility is
2 regional reliability. It implements its tariff on behalf of all stakeholders
3 throughout the large MISO footprint. In fulfilling its functions, MISO's focus
4 is properly on regional issues, rather than state- or utility-specific concerns.
5

6 Q. ARE THERE OTHER FACTORS THAT THE COMMISSION SHOULD TAKE INTO
7 CONSIDERATION?

8 A. Yes. As we described in great detail in our Resource Plan in Case No. PU-15-
9 019, the utility industry and the NSP System are in a period of uncertainty and
10 evolution. The utility industry as a whole will be impacted by the
11 implementation of existing and new environmental regulations. Further, the
12 NSP System may need to replace more than seventy-five percent of its energy
13 resources by 2035. While it is likely that it will take years for these issues to be
14 fully resolved, we must act in a very short timeframe to ensure we have
15 adequate resources in place from 2016 to the early 2020s.
16

17 Q. PLEASE DESCRIBE THE IMPACT THAT MISO-WIDE CAPACITY RETIREMENTS
18 THAT ARE CURRENTLY CONTEMPLATED BY THE COMPANY AND OTHER MISO
19 UTILITIES WILL LIKELY HAVE ON THE PRUDENCE OF MAKING A RESOURCE
20 ADDITION AT THIS TIME.

21 A. Our analyses indicate that the cost of generation development, especially
22 natural gas-fired generation, may become more expensive as demand for new
23 natural gas-fired generation increases due to the decommissioning of coal
24 plants in the MISO footprint. And, as mentioned, these plant retirements are
25 also expected to increase the costs of short-term capacity in MISO's voluntary
26 capacity auction. Taking a conservative approach with diversified energy
27 resources such as the solar resource additions that are the basis of this

1 proceeding will position the Company well for the long term in light of these
2 issues.

3

4 Q. ON PAGE 5:8-24, MR. DILLER DESCRIBES SOME POTENTIAL IMPACTS OF
5 HAVING EXCESS GENERATION IN THE MISO REGION. HOW DO YOU
6 RESPOND?

7 A. The Company appreciates Mr. Diller's discussion on this issue. However, I
8 believe the situation is more complicated.

9

10 It is important to distinguish between recovery of production (energy) costs
11 and recovery of capacity costs. Under MISO's current rules, we may only
12 include our production costs when we offer generation into the market.
13 Therefore, the energy markets only allow us to recover the marginal cost of
14 producing the energy. In contrast, we recover our capacity costs by including
15 our assets in rate base and recovering these investments through retail
16 revenues, or, in the case of merchant generation, through bilateral contracts
17 for the capacity.

18

19 When planning a utility system, one must plan for an optimal mix of energy
20 and capacity. In certain circumstances, the overall least-cost method of
21 providing energy and capacity to meet demand requirements is to install low-
22 cost capacity generation (*e.g.*, combustion turbines) that is not expected to run
23 often because of the high production costs to make this energy. The primary
24 purpose of this low-cost capacity is to ensure that there are adequate resources
25 available to meet peak demands; the energy value of that resource is of
26 secondary importance. Therefore, this resource has value to the system by
27 providing low-cost capacity since the system needs do not require the energy

1 from this resource to meet demand needs except for a very few hours during
2 the year.

3
4 It is rather complicated to identify the impact of a particular resource on
5 energy prices in the market. The peaking resource I mention above would
6 have little effect on energy pricing since it is designed to provide energy only
7 during limited hours of the year. Whereas an intermediate resource would
8 have more effect on the cost of energy since it is designed to produce more
9 energy when there are needs above what can be met by regular baseload
10 generation. This analysis becomes even more complicated when the impact of
11 intermittent resources such as solar and wind are taken into account.

12

13 Q. PLEASE SUMMARIZE YOUR COMMENTS ON THIS MATTER.

14 A. The interplay of the types of resources on the system, their effect on energy
15 pricing, and the carrying costs of capacity are what ultimately effects overall
16 costs to our customers. In certain circumstances we may have the opportunity
17 to add resources to our system that lower the overall costs of power to our
18 customers by reducing energy prices by more than the incremental increase in
19 capacity costs. This is the rationale behind most baseload power plants but
20 also was the underlying economic justification for adding the Pleasant Valley
21 and Border Winds projects to the NSP System. Although these resources
22 added investments to rate base, these costs were offset by zero cost energy,
23 thereby bringing down total system costs to our customers over their life.

24

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26

IV. PRUDENCE OF RESOURCE ADDITION

Q. MR. DILLER STATES ON PAGE 2:2-4 THAT INCREMENTAL NEW CAPACITY IS NOT NEEDED ON THE NSP SYSTEM AT THIS TIME. HOW DO YOU RESPOND?

A. I agree that our most recent demand forecast shows that we have sufficient capacity to serve our integrated system until 2024 without considering other issues. However, as I describe above, (1) we believe it is appropriate to plan conservatively to ensure we have resources available in case we experience an unexpected increase in demand, (2) obtaining the bare minimum of capacity to serve our peak-hour demand is not the only consideration that goes into deciding to add resources, and (3) we have other reasons to add solar capacity at this time, including the need to satisfy Minnesota’s Solar Energy Standard. On balance, we conclude that the overall needs of our integrated system are better served by adding the 187 MW solar portfolio at this time.

Q. ARE THERE OTHER CIRCUMSTANCES THAT WOULD ALSO SUPPORT THE PRUDENCE OF MAKING RESOURCE ADDITIONS TO THE SYSTEM NOW?

A. Yes. Even beyond preparing to supply customer demand if growth increases faster than presently forecasted, adding solar generation at this time is an appropriate choice under the circumstances. Those circumstances include: (1) anticipated MISO-wide capacity retirements; (2) the currently-favorable interest rate and cost environment for solar generation; (3) an uncertain environmental regulatory environment and the likelihood that regulations will increasingly focus on carbon-free generation; and (4) our need to meet the Solar Energy Standard of the State of Minnesota.

1 Q. MR. DILLER SAYS THAT THE 187 MW SOLAR PORTFOLIO IS NOT A “LEAST-
2 COST” RESOURCE. HOW DO YOU RESPOND?

3 A. Mr. Diller’s observation is correct when looked at from one perspective, but it
4 does not fully address all of the considerations we include in development and
5 selection of resources. Let me explain:

6

7 I would agree that on a per-kWh basis, solar capacity and energy is not least-
8 cost when compared to natural gas generation or even wind generation.
9 However, when we make resource decisions, I do not believe the unit cost of
10 a resource can be considered in isolation. For example, prudent resource
11 planning would take into account policy drivers for a particular resource
12 addition; market conditions which impact the cost of the generation in
13 comparison to potential future costs; future system retirements; and resource
14 diversity.

15

16 Mr. Diller does not explain what he is measuring against when he concludes
17 the 187 MW solar portfolio is not least-cost. Given the Solar Energy Standard
18 compliance obligation in Minnesota, I believe the most appropriate
19 comparison is to consider the cost of this solar portfolio with the cost of
20 similar solar projects that were available to us at the time we made this
21 selection. As we describe in our filing, the three solar resources being
22 considered in this case were selected because they were the least-cost solar
23 resources that met the requirements of the competitive request for proposal
24 (RFP) that we conducted.

25

26 Q. MR. DILLER SUGGESTS THAT LESS EXPENSIVE RESOURCE OPTIONS ARE
27 AVAILABLE TO THE COMPANY. HOW DO YOU RESPOND?

1 A. As I mention above, I agree that the nominal cost of natural gas and wind
2 generation is less than solar on a per kWh basis. But it is also important to
3 consider other factors, such as the ones I described above.

4
5 I note that our resource plan contemplates significant additional solar
6 generation during the planning horizon. Thus adding solar to the system now
7 is appropriate in light of the overall circumstances. I also note that solar
8 generation, while intermittent in nature, is generally producing energy during
9 the peak periods of the day. This means that solar generation is available to
10 offset high peak energy market pricing. This is in contrast to wind generation
11 which is more likely to experience intermittent output primarily during non-
12 peak periods.

13 14 **V. POLICY CONSIDERATIONS**

15 16 **A. Multi-State Considerations**

17 Q. YOU MENTIONED THAT ONE OF THE REASONS FOR SELECTING SOLAR
18 RESOURCES AT THIS TIME IS THE NEED FOR THE COMPANY TO COMPLY WITH
19 MINNESOTA'S SOLAR ENERGY STANDARD. IS NORTH DAKOTA REQUIRED TO
20 FOLLOW MINNESOTA'S ENERGY POLICY AS IT PERTAINS TO SOLAR ENERGY?

21 A. No. North Dakota is free to implement its own state energy policies.

22
23 I agree with Mr. Diller's observation on page 8:5-10 of his testimony that
24 North Dakota and Minnesota "should seek to mutually and beneficially
25 coexist whenever possible so long as doing so is not detrimental to our own
26 citizenry." However, there is more to consider in the determination of

1 “detrimental” than simply whether the resource addresses a policy
2 requirement in another state.

3

4 Q. PLEASE EXPLAIN.

5 A. The Company jointly plans for and operates an integrated system that serves
6 more than 1.8 million retail electric customers in Michigan, Minnesota, North
7 Dakota, South Dakota, and Wisconsin. We have successfully planned for and
8 managed the integrated NSP System to meet all of our customers’ needs for
9 almost 100 years. Because customers in all of our states are served by the
10 same system, we have been able to achieve significant economies of scale that
11 provide benefits to all of our customers in all of the states we serve.

12

13 Q. CAN THE COMPANY ACCOMMODATE ALL OF THE ENERGY POLICIES OF ALL OF
14 ITS STATES?

15 A. The simple fact is that Xcel Energy is *required* to comply with the energy
16 policies of all of the states in which we provide service, and we are constrained
17 by the regulatory processes prescribed by lawmakers and regulators in each
18 state. We are finding it increasingly difficult to accommodate all of the various
19 policies, as each state in which we provide electric service has different
20 regulatory constructs and oversight regimes. However, we continue to believe
21 that the benefits of our large integrated system outweigh the costs that may be
22 imposed by any particular state.

23

24 Q. HOW DOES THE COMPANY ACCOMMODATE THE INTERESTS OF DIVERGENT
25 STATE POLICIES IN MAKING RESOURCE CHOICES?

26 A. In making resource choices we take into account existing and evolving
27 environmental regulations; state public policy choices from each of our

1 jurisdictions; changing customer expectations; the condition of our existing
2 generation fleet, which is aging and will require significant change in the
3 coming years; and emerging technologies that change the way energy is
4 generated and delivered. This multifaceted set of issues sometimes means that
5 we may choose a resource to meet state policy goals in an amount greater than
6 what our forecast might suggest, particularly in a circumstance where we have
7 experienced forecast volatility and/or impending loss of significant cost
8 reduction incentives.

9

10 Q. WHAT SHOULD THE COMMISSION CONSIDER IN DECIDING WHETHER NSP'S
11 RESOURCE DECISIONS ARE "DETRIMENTAL TO OUR OWN CITIZENRY" AS
12 SUGGESTED BY MR. DILLER?

13 A. The Company believes it is important for the Commission to consider a broad
14 range of factors including the interests of North Dakota customers as a whole,
15 rather than focusing on any particular consideration. In other words, when
16 viewing our resource choices with respect to our North Dakota customers, it
17 is important to balance the cost impact of meeting certain non-North Dakota
18 energy policy requirements with the economies of scale, and therefore lower
19 costs, provided by the large demand from the other states in the NSP System.
20 Even if the Company makes resource acquisitions in part to accommodate
21 Minnesota's energy policies, it does not necessarily mean that our overall
22 integrated resource mix is not in the best interest of all of our customers.

23

24 Q. PLEASE EXPLAIN.

25 A. What I mean by this is that the North Dakota citizenry experiences a variety
26 of costs and benefits in being served by NSP's integrated five-state system.
27 For example, our North Dakota customers are able to take advantage of their

1 pro rata share of the Company's extensive nuclear, coal, natural gas and large
2 hydro generation. These resources, which provide low-cost and efficient
3 generation, would likely not be as available to our North Dakota customers if
4 our North Dakota operation was a stand-alone system. This is because having
5 the scope and scale of the other ninety-five percent of the NSP System allows
6 the Company to obtain the critical mass to achieve significant economies of
7 scale.

8
9 The Commission has historically approved the North Dakota share of the
10 Company's resource choices, including even wind and biomass additions to
11 the system. While many of those resources were added in furtherance of
12 Minnesota energy policy, our North Dakota customers benefited overall from
13 the integrated system while accepting the costs of those policy choices. In
14 addition to the low-cost baseload facilities I mentioned earlier, the benefits
15 included transmission system reliability improvements and fuel price volatility
16 hedges from non-thermal generation additions.

17
18 In the end, the Company believes that there is a balance to be struck between
19 (1) the benefits of a large, multi-state system, and (2) accommodating the
20 requirements of a particular state's energy policy.

21
22 Q. SHOULD THE COMMISSION ALSO CONSIDER THE QUALITATIVE FACTORS OF
23 THE COMPANY'S PROPOSED SOLAR RESOURCE ADDITIONS?

24 A. Yes. As we discuss at length in our recently filed resource plan, the utility
25 industry and the NSP System are in a period of great change and significant
26 uncertainty. We believe that our resource decisions during this time should be
27 made with an eye to the future. The fuel price hedge and resource diversity

1 value of our 187 MW solar portfolio are exactly the types of considerations
2 that the Commission should take into account while evaluating our request.
3 The Commission has been making these types of qualitative evaluations since
4 at least 2008¹ and should continue to do so.

5

6 Q. PLEASE ELABORATE.

7 A. Our underlying purpose for making our proposed solar resource addition
8 notwithstanding, there are material qualitative advantages of adding these
9 resources to the NSP System at this time that argue for their prudence.

10

11 Solar is a developing resource and making utility scale additions to the NSP
12 System will provide us with operational experience with this type of resource.
13 Further, solar resources provide us with a hedge against other fuels, adding to
14 our resource diversity. These resource additions will also help to position us
15 should future carbon regulations in fact become mandatory. This is similar to
16 the Company's experience with wind generation. While Minnesota policy was
17 a driver in our initial additions of wind to the system, we are now seeing wind
18 be an economic resource that can and does provide benefits to our customers,
19 including comparatively low cost of energy that minimizes upside fuel price
20 risk.

21

22 These qualitative factors are the same types of factors that the Commission
23 has, in the past, used to recognize the prudence of renewable resource
24 additions such as wind that were not least-cost (but were a reasonable cost for
25 that resource type) and not utilized to meet an identified capacity deficit.²

¹ See Case Nos. PU-06-481; PU-06-482.

² See, e.g. Case No. PU-08-907.

1

2 Given the uncertain future, we believe that a qualitative evaluation of our
3 proposed resource addition is appropriate and will further demonstrate the
4 prudence of our resource additions at this time at a system-wide net cost of
5 only \$14 million (compared to a total system cost of more than \$1 billion) on
6 a present value revenue requirements basis.

7

8 **B. Restack**

9 Q. WHAT OPTIONS DOES THE COMMISSION HAVE IF IT DOES NOT APPROVE THE
10 COMPANY'S REQUEST?

11 A. I believe there are two basic options available to the Commission: (1) allow
12 both the capacity and energy of the 187 MW solar portfolio to be re-priced
13 through the North Dakota Restack process, or (2) direct-assign resources to
14 be consistent with divergent state energy policies. Each of these choices
15 carries important policy considerations.

16

17 Q. WHAT IS THE COMPANY'S RECOMMENDATION?

18 A. In this circumstance, we respectfully request that the capacity and energy of
19 any resource for which the Commission does not grant an ADP be eligible to
20 be included in the Restack process.

21

22 Q. PLEASE SUMMARIZE THE NORTH DAKOTA RESTACK PROCESS.

23 A. As the Commission is aware, development of a Restack Agreement with
24 Commission Staff is guided by ten negotiating principles adopted by the
25 Commission in the Settlement Agreement adopted in our last rate case. Key
26 among these principles is that both the energy and capacity costs of any new
27 resource addition (such as those proposed by the Company here) rejected by

1 the Commission be re-priced using a suitable marginal cost proxy to essentially
2 remove from North Dakota rates what the Commission has determined to be
3 unacceptable policy premium costs of the resource. By addressing both the
4 capacity and energy impacts of such resource additions, the Restack will
5 acknowledge the “used and useful” nature of these resource additions to the
6 NSP System while identifying and mitigating the cost impact for our North
7 Dakota customers of energy policy decisions made in other states with which
8 the Commission does not concur but which provide used and useful capacity
9 and energy to the NSP System.

10

11 The Settlement Agreement’s negotiating principles indicate that the
12 appropriate proxy pricing would reflect the marginal cost of the next unit of
13 capacity or energy available to be added to the system. We are currently
14 negotiating the appropriate capacity and energy proxy pricing framework for
15 this “marginal” cost with Commission Staff. The final Agreement will
16 establish the “used and useful” pricing for any new resource additions subject
17 to the Restack.

18

19 Q. WHY DO THE RESTACK NEGOTIATING PRINCIPLES INCLUDE A PROXY PRICING
20 FOR CAPACITY EVEN IF THERE IS NO DEMONSTRATED CAPACITY DEFICIT
21 JUSTIFYING THE ADDITION OF A PARTICULAR RESOURCE?

22 A. As I mentioned, the Restack concept is premised on maintaining the
23 Company’s ability to plan and operate the NSP System as an integrated system
24 while at the same time addressing the impact of different state energy policies
25 on our North Dakota customers. Using a proxy price for energy and capacity
26 provides an objective standard (*i.e.* the cost of the next increment of energy or

1 capacity to the system) to determine what type of “policy premium” exists for
2 the resource addition.

3

4 Q. WHAT DO YOU MEAN BY THE TERM “POLICY PREMIUM?”

5 A. In this instance, Minnesota’s energy policy calls for the Company to deploy
6 additional resources that are of certain types and sizes. The Restack provides
7 a mechanism to quantify the additional costs of both the capacity and energy
8 from these resources due to other states’ policy preferences. This “policy
9 premium” provides a way to help ensure North Dakota’s rates better reflect
10 North Dakota energy policy judgments while allowing the Company to
11 continue to make resource decisions for the integrated system.

12

13 Q. HOW DOES THE RESTACK CONCEPT MAINTAIN A BALANCE BETWEEN NORTH
14 DAKOTA’S ENERGY POLICY JUDGMENTS AND THE COMPANY’S RESOURCE
15 SELECTIONS?

16 A. By determining a proxy price for the capacity and energy, North Dakota
17 customers are still contributing to used and useful resources on the integrated
18 system and specifically for the energy they use and the capacity that is serving
19 them. In this manner we are able to appropriately allocate the energy and
20 capacity of all of the resources on the integrated NSP System to all of our
21 customers, and thereby maintain the integrated nature of the NSP System.

22

23 Q. If THIS 187 MW SOLAR PORTFOLIO IS NOT APPROVED BY THE COMMISSION,
24 WHY WOULD IT BE APPROPRIATE TO INCLUDE IT IN THE RESTACK?

25 A. Yes. Should the Commission not deem our proposal prudent, we believe that
26 including the 187 MW solar portfolio in the Restack allows us to continue to
27 plan and operate the NSP System on an integrated basis while a long-term or

1 permanent solution to the state divergent energy policy issue is being
2 developed.

3

4 Q. HOW WILL THE RESTACK ALLOW THE COMPANY TO CONTINUE TO PLAN AND
5 OPERATE THE NSP SYSTEM ON AN INTEGRATED BASIS?

6 A. The Restack provides a short- to mid-term solution to the issue of
7 accommodating divergent state policies by pricing and excluding from North
8 Dakota rates the “policy premium” associated with those resources. It
9 therefore reflects an opportunity to address policy differences while at the
10 same time providing the Company with at least partial recovery for the
11 capacity and energy that are actually being used to serve North Dakota
12 customers.

13

14 Q. IF THE COMMISSION DOES NOT APPROVE THIS RESOURCE AND IT IS
15 SUBSEQUENTLY INCLUDED IN THE RESTACK, WOULD NORTH DAKOTA
16 CUSTOMERS BE PAYING FOR ENERGY AND CAPACITY THAT IS NOT NEEDED?

17 A. No. With respect to energy, this resource addition will likely displace the
18 production of energy from other resources on the system. Because the system
19 must always balance generation and load, all of our customers use the energy
20 that is produced by these new resource additions when they are generating.³
21 Therefore, the Restack is merely re-pricing energy that is being consumed by
22 our North Dakota customers.

23

³ The Company may also sell energy to third parties. Under the Settlement Agreement in Case No. PU-12-813, we will credit back to customers 100 percent of the earnings on such sales.

1 Q. IF THE RESOURCE ADDITION SIMPLY DISPLACES ENERGY ALREADY ON THE
2 SYSTEM, WOULDN'T THAT SUGGEST THE APPROPRIATE PROXY IS THE AVERAGE
3 SYSTEM FUEL COST?

4 A. There is no "correct" answer to this question, only different policy outcomes
5 that can be achieved through the use of proxy pricing. It is arguable that the
6 true financial impact to the NSP System of the 187 MW solar portfolio would
7 be the actual production costs of the NSP generation resources that are
8 displaced by the 187 MW solar portfolio when the solar portfolio is
9 generating. However, because MISO and not the Company dispatches all
10 generation in MISO, the MISO Locational Marginal Pricing for the hours that
11 the 187 MW solar portfolio is generating represents the cost to the Company
12 of the energy it would have used to replace the generation of the solar
13 portfolio.

14
15 In contrast, utilizing system average as a replacement proxy does not account
16 for the marginal cost of the energy that the 187 MW solar portfolio displaces.
17 Rather, a system average cost of fuel without the 187 MW solar portfolio
18 represents a look at system costs without the 187 MW solar portfolio or some
19 other resource that would have been generating in its stead.

20
21 Q. PLEASE ADDRESS WHETHER NORTH DAKOTA CUSTOMERS WOULD BE PAYING
22 FOR *CAPACITY* THAT THEY DO NOT NEED.

23 A. Unlike energy, capacity is additive to the system and does not displace other
24 capacity. Our resource planning efforts take into account the lumpy nature of
25 capacity additions when planning for future additions to the system. By
26 providing for capacity in the Restack Agreement, the negotiating principles in
27 our rate case Settlement Agreement recognize the impact that capacity

1 additions have on the need for and timing of the next increment of capacity
2 for the system. When the Company adds the capacity represented by the 187
3 MW solar portfolio, the size, type, and timing of any future resource additions
4 will be affected.

5

6 Q. WHY MUST CAPACITY BE INCLUDED IN THE RESTACK TO MAINTAIN THE
7 INTEGRITY OF THE INTEGRATED SYSTEM?

8 A. In short, we plan and operate the NSP System on an integrated basis, and as a
9 result the addition of new resources impacts our system-wide capacity needs
10 into the future for all of the states we serve. If our North Dakota customers
11 do not contribute to the addition of new used and useful capacity, I believe it
12 would be inappropriate for us to allocate the new capacity to address any
13 future capacity shortfalls for our North Dakota customers. Rather, the
14 Company would seek to mitigate its inability to recover the costs of this new
15 capacity either by reallocating it to other jurisdictions within our integrated
16 system, or seek to sell the new capacity to a third party. Doing so would be a
17 departure from the integrated system approach.

18

19 **C. Implications of Direct Assignment**

20 Q. MR. DILLER RECOMMENDS THAT XCEL ENERGY DIRECT-ASSIGN GENERATION
21 TO ITS NORTH DAKOTA CUSTOMERS AS A WAY TO ADDRESS DIVERGENT STATE
22 ENERGY POLICIES. HOW DO YOU RESPOND?

23 A. Mr. Diller states his policy perspective on page 8:21-23 that “basic cost
24 allocation and rate design principles require that costs be assigned to the cost
25 causers whether allocating costs between states or to various customer
26 classes.” I agree with Mr. Diller’s perspective and that cost causation is an

1 important consideration. But cost causation isn't the only relevant criteria to
2 inform the Commission's consideration.

3

4 I think it is important that the Commission also recognize that our integrated
5 five-state system allows us to plan and implement it on a consolidated basis in
6 order to meet all of our customers' needs as well as complying with all of the
7 policies in all of our states. Overall this has proved to be a cost-effective way
8 for us to serve our North Dakota customers as well as the customers in the
9 other four states. While it may be true that some of the costs we incur are
10 designed to address specific policies in Minnesota, we do not believe this
11 nullifies the overall value of the integrated system to our customers in North
12 Dakota.

13

14 Q. WHAT ARE SOME OF THE IMPLICATIONS IF THE COMMISSION DECIDES TO
15 ADOPT A POLICY OF DIRECT-ASSIGNING GENERATION CONSISTENT WITH
16 NORTH DAKOTA'S ENERGY POLICY?

17 A. If one state requires that we direct-assign generation to avoid the impact of
18 another state's energy policy, we will no longer be able to manage the NSP
19 System as an integrated whole since some capacity component of our resource
20 additions will not be available to the system. This will require us to plan for
21 and manage our North Dakota customers on a separate basis than the
22 remainder of the NSP System.

23

24 Q. WOULD THE OUTCOME BE THE SAME IF THE COMMISSION DENIED AN ADP
25 FOR THE COMPANY'S REQUESTED RESOURCE ADDITION AND DID NOT ALLOW
26 THE ENERGY OR CAPACITY COSTS TO BE RE-PRICED THROUGH THE RESTACK
27 PROCESS?

1 A. Yes. Rejecting the capacity from the Restack, as Mr. Diller recommends,
2 would eliminate this capacity from consideration for serving our North
3 Dakota customers. This will make it impossible to continue to fully integrate
4 our North Dakota customers into the NSP System on a going-forward basis.

5

6 Q. PLEASE EXPLAIN.

7 A. Eliminating the capacity component from recovery in the Restack would
8 mean that North Dakota could not take advantage of that capacity since it
9 would be making no contribution to the cost of that generation. This would
10 require the Company to plan separately for how to meet North Dakota's
11 capacity needs. Ultimately, this would result in a separate analysis of when
12 new generation is needed to serve our North Dakota customers and would
13 require that we deploy generation specifically dedicated to North Dakota.

14

15 Q. DO YOU HAVE GENERAL CONCERNS OVER DIRECT-ASSIGNING CAPACITY AWAY
16 FROM NORTH DAKOTA?

17 A. Yes. In order to maintain the integrated system, we must be able to allocate
18 all of our generation across all of our states. If a state chooses to reject a
19 particular resource, then that generation must be allocated away from that
20 state to avoid the state using capacity it is not paying for. Ultimately, direct-
21 assignment would require the Company to separate its utility operations by
22 jurisdiction to ensure that all capacity being dedicated to each jurisdiction is
23 properly accounted for.

24

25 Q. ARE THERE OTHER PROBLEMS WITH THE CONCEPT OF DIRECT-ASSIGNMENT?

26 A. Yes. Direct-assigning generation away from North Dakota raises the risk that
27 North Dakota could find itself in a capacity deficit position (on an individual

1 basis) even if NSP's overall portfolio would have enough generation to serve
2 North Dakota but for the fact that some of that generation was direct-
3 assigned away.

4

5 Q. WHAT WOULD THE COMPANY HAVE TO DO IF IT FORECASTED A CAPACITY
6 DEFICIENCY FOR ITS NORTH DAKOTA OPERATION AND WAS UNABLE TO PLAN
7 FOR THE NSP SYSTEM ON AN INTEGRATED BASIS?

8 A. We would have to procure additional resources specifically dedicated to North
9 Dakota to make up for the deficit created by direct-assigning existing capacity.
10 We could do this by purchasing capacity from another utility (if it was
11 available) or we could try to obtain that capacity using the MISO voluntary
12 capacity auction. However, as described above, procuring capacity through
13 those market mechanisms is risky and not assured. We could also seek to
14 obtain capacity through either short-term or long-term bilateral transactions.

15

16 Another alternative is that the Company would need to build additional
17 capacity for our North Dakota customers to meet that deficit. In this
18 scenario, we would consider the size, type and timing of construction to
19 address this deficit and would expect that it would be a smaller unit than
20 would be possible if we were planning for the NSP System on an integrated
21 basis.

22

23 I note that because this would be a resource dedicated to meeting only our
24 North Dakota customers' capacity needs, we would anticipate direct-assigning
25 these costs to our North Dakota jurisdiction.

26

27 Q. WHAT DO YOU RECOMMEND?

1 A. I recommend that the Commission decline to direct-assign generation on the
2 Company's system and that the Commission allow us to reflect the used and
3 useful portion of the capacity we propose to add to our system. In this
4 instance, we recommend that the Commission grant the requested ADP for
5 the 187 MW solar portfolio or, in the alternative, allow both the energy and
6 capacity from this purchase to be re-priced through the North Dakota Restack
7 process.

8

9

VI. CHANGES TO PPAS

10

11 Q. HAVE THE PPAS CHANGED SINCE THE TIME THEY WERE FILED WITH THE
12 COMMISSION WITH THE COMPANY'S APPLICATION?

13 A. Yes, minor edits were made to the PPAs. The only substantive edit was to
14 conform the regulatory approval language with the PPA we entered into for
15 the Geronimo Solar Project that is the subject of Case No. PU-15-095. These
16 conforming changes were made by letter agreement between the Company
17 and PPA developers and are attached as Schedule 2⁴.

18

19 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

20 A. Yes, it does.

⁴ See also March 24, 2015 ORDER APPROVING SOLAR PORTFOLIO in MPUC Docket No. E002/M-14-162.