



Direct Testimony and Schedule
Laura McCarten

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-_____
Exhibit ____ (LM-1)

Policy Testimony

November 7, 2014

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Resume

Schedule 1

1 I. INTRODUCTION AND QUALIFICATIONS

2

3 Q. PLEASE STATE YOUR NAME AND TITLE.

4 A. My name is Laura McCarten. I am Regional Vice President for Northern
5 States Power Company (NSP or the Company).

6

7 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

8 A. I am responsible for regulatory, legislative, and customer and community
9 relations in North Dakota, South Dakota, and Minnesota. I provide strategic
10 leadership regarding the development and implementation of our initiatives to
11 cost effectively meet the energy needs of our retail customers and the
12 communities we serve. My resume is included as Exhibit__(LM-1),
13 Schedule 1.

14

15 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

16 A. I provide support for our request for an Advance Determination of Prudence
17 (ADP) for our proposed acquisition of a single portfolio consisting of
18 187 MW of solar generating resources (Solar Portfolio) for the NSP integrated
19 System. In my testimony, I:

- 20 • Describe our proposed 187 MW Solar Portfolio;
- 21 • Discuss the prudence of the Solar Portfolio;
- 22 • Discuss the rate and regulatory impacts; and
- 23 • Discuss the impact on our resource plans.

24

25 Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

26 A. In addition to my Policy Testimony, the Company sponsors the following
27 witness:

- 1 • *Kurtis J. Haeger* – who provides more detailed information with respect
2 to our resource additions and resource planning.

3

4 Q. PLEASE SUMMARIZE THE COMPANY’S PROPOSED 187 MW SOLAR PORTFOLIO.

5 A. We are proposing to acquire the single 187 MW portfolio comprised of three
6 solar projects through fixed price power purchase agreements (PPA). Our
7 proposal will enable us to meet our requirements under Minnesota’s Solar
8 Energy Standards (SES) in the most cost-effective manner while adding clean,
9 carbon-free y capacity to the NSP System.

10

11 **II. PROPOSED RESOURCE ACQUISITIONS**

12

13 Q. PLEASE DESCRIBE THE COMPANY’S PROPOSED RESOURCE ACQUISITION.

14 A. We are proposing to purchase the energy from three solar projects consisting
15 of (1) a PPA for the output of the Marshall Solar Project, a 62.25 MW solar
16 facility to be developed by NextEra and located near Marshall, Minnesota; (2)
17 a PPA for the output of the MN Solar 1 Project, a 24.75 MW solar facility to
18 be developed by juwi solar and located near Tracy, Minnesota; and (3) a PPA
19 for the output of 100 MW North Star Solar project to be developed by
20 Community Energy Resources and located near North Branch, Minnesota.
21 We expect all of these projects to begin operation in late 2016.

22

23 Q. WHY IS THE COMPANY MAKING THESE RESOURCE ADDITIONS?

24 A. We are purchasing energy (and obtaining the associated accredited capacity)
25 from these resources primarily to comply with the Minnesota SES. The state
26 of Minnesota recently enacted a law (Minn. Stat. § 216B.1691, subd. 2f(a)-(c))
27 that requires the Company to serve 1.5 percent of its Minnesota retail

1 customer load with solar energy by 2020, and establishes a 10 percent solar
2 energy objective for Minnesota by 2030. But the Solar Portfolio will also
3 allow the Company to avoid additional purchases of natural gas and other
4 market energy that we would have otherwise needed to obtain to fuel the
5 production of generation from other resources.

6
7 To help fulfill our obligations under this new Minnesota law, the Company
8 initiated a Request for Proposal (RFP) for utility-scale solar resources in April
9 2014. We received over 100 proposals for over 2,100 MW of solar
10 photovoltaic (PV) generating resources from 36 developers. The responses
11 we received provided relatively attractive pricing for solar resources, with 15
12 projects comprising 630 MW of generating capacity falling at or below our
13 initial screening threshold of \$85/MWh.

14
15 The three projects comprising our 187 MW Solar Portfolio were selected
16 because (1) we need significant solar resources for SES compliance, and (2)
17 the pricing reflects a 30 percent investment tax credit (ITC). We believe that
18 purchasing power from the 187 MW Solar Portfolio, combined with
19 increasing behind-the-meter solar generation and community solar gardens,
20 will allow us to meet our minimum SES obligations through at least 2030.

21
22 Q. WHY IS THE COMPANY SEEKING AN ADP FOR RESOURCE ADDITIONS
23 NECESSARY TO MEET MINNESOTA'S SOLAR ENERGY STANDARDS?

24 A. As the Commission is aware, the Company and its affiliate Northern States
25 Power Company, a Wisconsin corporation (NSPW) operate a five state
26 integrated electric system serving customers in ND, SD, MN, WI, and MI.
27 Through the operation of this integrated system, the energy and capacity

1 provided by the 187 MW Solar Portfolio will be used to serve our customers
2 in all five of these states. Therefore, a proportional share of the costs of these
3 solar resources will also be allocated to each of these jurisdictions, if approved
4 by the respective regulatory bodies. Consequently, we are seeking
5 Commission approval for these resources pursuant to our commitments to file
6 applications for ADPs with the Commission when we add resources over
7 50 MW of size to the integrated system.

8
9 **III. PRUDENCE OF THE RESOURCE ADDITION**

10
11 Q. ARE THE PROPOSED RESOURCE ADDITIONS PRUDENT?

12 A. Yes. As a multi-jurisdictional utility, the Company is required to comply with
13 the laws and policies in all of the states we serve. As mentioned, this 187 MW
14 Solar Portfolio will help enable us to comply with Minnesota's SES. By
15 contracting for the output of utility-scale projects that will capture the pricing
16 benefits of the ITC, the Company has secured reasonably priced resources
17 that will help meet our SES obligations, have a modest impact on rates, and
18 provide valuable system energy, fuel hedge value, and environmental
19 regulation hedge value for the benefit of all our customers in all of the states
20 we serve. Consequently, acquisition of the 187 MW Solar Portfolio is
21 prudent.

22
23 Q. PLEASE SUMMARIZE THE QUALITATIVE BENEFITS OF THE RESOURCE
24 ADDITIONS.

25 A. Although the proposed 187 MW Solar Portfolio will modestly increase costs
26 to our customers, these projects will increase the diversity of our resource mix
27 by providing clean emission free energy, a hedge against volatile natural gas

1 prices and potential environmental regulation. The projects will also provide
2 accreditable capacity that will help to displace the need for future capacity
3 resources. The 187 MW Solar Portfolio will also generate Solar RECs (S-
4 RECs) for our North Dakota customers that may be able to be monetized in
5 the future as the S-REC market matures. These qualitative benefits partially
6 offset the modest cost impact of this Solar Portfolio, further demonstrating its
7 prudence. Company Witness Mr. Kurtis J. Haeger discusses these impacts in
8 more detail in his Direct Testimony.

9
10 Q. PLEASE SUMMARIZE THE COST IMPACTS OF THE ACQUISITION OF THE 187 MW
11 SOLAR PORTFOLIO.

12 A. Based on our analysis (which does not reflect environmental externalities such
13 as carbon costs), we conservatively estimate that the 187 MW Solar Portfolio
14 will have a \$14 million system-wide annual present value revenue requirement
15 (PVRR) impact over the lives of the three projects.

16
17 The 187 MW Solar Portfolio represents some of the most attractively priced
18 solar energy available in the region, is cost-effective when the qualitative
19 impacts and additional capacity of the resources are considered, is required for
20 Minnesota SES compliance, and is therefore a prudent resource addition. Mr.
21 Haeger discusses the impact of these projects in more detail in his Direct
22 Testimony.

23 24 IV. POLICY IMPACTS

25
26 Q. MAY THE COMPANY RECOVER ANY COSTS FOR THE 187 MW SOLAR
27 PORTFOLIO IN NORTH DAKOTA WITHOUT AN ADP?

1 A. Without approval of an ADP, the Company will not be able to include these
2 PPAs in the derivation of its monthly Fuel Cost Rider (FCR) rate. As
3 mentioned above, the Company committed to filing applications for ADPs
4 for resource additions over 50 MW in our 2008 rate case (Case No. PU-07-
5 776). Additionally, the Company committed to filing ADP applications in a
6 timely manner in the Prairie Rose Wind ADP proceeding (Case No. PU-12-
7 059). Lastly, in the Settlement approved in our most recent rate case (Case
8 No. PU-12-868) the Company agreed that the ADP process will perform a
9 gatekeeping function and that no resource acquisition over 50 MW may be
10 included in the calculation of our FCR without an ADP.

11
12 The Company is meeting its commitments by filing this ADP Application at
13 this time. Under the Settlement in our last rate case, the Company may not be
14 able to recover the full costs of the 187 MW Solar Portfolio through the FCR
15 without the Commission affirmatively granting an ADP.

16
17 Q. ARE THE COMPANY'S OBLIGATIONS UNDER THE PPAS CONDITIONED ON
18 APPROVAL OF THE COMMISSION?

19 A. Yes. All of the relevant agreements contain what is known as a "condition
20 precedent," which requires that the Commission grant an ADP for each of the
21 projects *before* the Company is required to perform under the contracts. We
22 also have the right to waive the condition precedent and move forward with
23 the projects if all required regulatory approvals are not timely attained.

24
25 Q. IS THE 187 MW SOLAR PORTFOLIO CONSISTENT WITH NORTH DAKOTA
26 ENERGY POLICY?

27 A. The Company believes that it is the Commission's role to determine if a

1 particular resource addition is consistent with state energy policy. This ADP
2 proceeding will provide the Commission an opportunity to review the
3 proposed resource addition and make such a determination.

4

5 We do, however, recognize the Commission's continuing concern with the
6 impact of Minnesota energy policies on our North Dakota customers, due to
7 the integrated nature of our system. In light of this concern, and consistent
8 with our commitments in the Settlement of our most recent rate case, the
9 Company has been working with Commission Staff to develop a Negotiated
10 Agreement to implement a system "Restack" as contemplated in the
11 Settlement.

12

13 The Company believes this work has been constructive in developing a
14 reasonable Restack approach, as well as identifying the potential impacts of
15 the Restack, and ways to mitigate those impacts on our North Dakota
16 customers, the Company, and our customers in all of our other affected
17 jurisdictions. We believe we are on track to file a Negotiated Agreement with
18 the Commission by the June 30, 2015 deadline provided for in the Settlement,
19 if not sooner.

20

21 Q. IF THE COMMISSION DENIES THE COMPANY'S APPLICATION FOR AN ADP FOR
22 THE 187 MW SOLAR PORTFOLIO, WOULD THIS RESOURCE ADDITION BE
23 INCLUDED IN THE NEGOTIATED AGREEMENT?

24 A. The Company does not want to prejudge the outcome of the Restack
25 negotiations. However, generally speaking, should the Commission deny the
26 Company's application for an ADP for the 187 MW Solar Portfolio because it
27 is incompatible with North Dakota energy policy, it would be the Company's

1 intention that this resource addition would be addressed in the Negotiated
2 Agreement implementing the Restack.

3
4 **V. RESOURCE PLANNING IMPACTS**
5

6 Q. WILL THE COMPANY BE MAKING ANY ADDITIONAL RESOURCE ADDITIONS TO
7 COMPLY WITH THE MINNESOTA SES?

8 A. The 187 MW Solar Portfolio is intended to be the principal utility-scale
9 resource addition the Company will make to meet its 1.5 percent SES
10 obligations in Minnesota. Our current plans are to meet the remainder of our
11 SES obligations through small, behind-the-meter solar installations, such as
12 rooftop solar, and through Minnesota's new Community Solar Garden
13 program. I note that the Company is required to meet ten percent of its SES
14 obligations through these small scale solar programs. Mr. Haeger provides
15 additional information with respect to the Company's Minnesota SES
16 compliance plans.

17
18 Q. WILL ANY OF THE COSTS OF THESE SMALL SCALE SOLAR PROGRAMS BE
19 ALLOCATED TO THE COMPANY'S NORTH DAKOTA CUSTOMERS?

20 A. To the extent that any of the costs of these small scale solar programs would
21 be allocated to our North Dakota customers through the Company's normal
22 allocation processes, the terms of the Settlement Agreement in our most
23 recent rate case would not allow the permanent inclusion of these costs in the
24 Company's North Dakota rates without ultimate Commission review. More
25 specifically, in our last rate case, the Company and Advocacy Staff agreed to a
26 process that will provide for timely Commission review of smaller resource
27 additions to the integrated system to determine whether the resource's energy

1 and related costs should be included in the Company's North Dakota FCR.
2 In the event we would allocate the costs of these small scale solar resources
3 under our normal allocation procedures to our North Dakota jurisdiction,
4 Commission review of the resources will be conducted through the agreed-to
5 FCR review process.

6

7 Q. DOES THE CAPACITY FROM THE 187 MW SOLAR PORTFOLIO AFFECT THE
8 COMPANY'S CAPACITY NEEDS IN THE 2017-2019 TIME FRAME IDENTIFIED IN
9 CASE NOS. PU-13-194 AND PU-13-195 OR ITS COMMITMENTS TO CONSTRUCT
10 THERMAL GENERATION IN NORTH DAKOTA BY 2036?

11 A. The 187 MW Solar portfolio will provide some additional capacity beginning
12 June of 2018. We do not believe that the addition of this capacity will have a
13 material impact on our resource needs in 2017 to 2019 or our commitments
14 with respect to construction of North Dakota based generation that were
15 made in the Settlement Agreement in our most recent rate case.

16

17 Q. HAS THE COMPANY SELECTED A RESOURCE TO MEET ITS IDENTIFIED
18 CAPACITY NEEDS IN THE 2017-2019 TIME FRAME?

19 A. Not yet. The Minnesota Competitive Acquisition Process (CAP) is still
20 ongoing. The CAP proceeding is currently scheduled for hearing before the
21 Minnesota Public Utilities Commission (MPUC) in early December 2014, and
22 we expect a final order from the MPUC by the end of the year. Mr. Haeger
23 provides further information with respect to the Company's forecasted
24 resource needs and the status of the CAP proceeding.

25

26 As agreed-to in the Settlement in our most recent rate case, and consistent
27 with other commitments the Company has made to the Commission, should

1 the Company seek to acquire a resource addition as part of the CAP process
2 (other than a resource for which the Commission has already issued an ADP),
3 the Company will file an application for an ADP for that resource.
4

5 Q. DOES THE COMPANY STILL PLAN TO MOVE FORWARD WITH THE 187 MW
6 SOLAR PORTFOLIO IF THE GERONIMO SOLAR PROJECT IS SELECTED AS PART OF
7 THE CAP PROCEEDING?

8 A. The Company believes that the 187 MW Solar Portfolio is the most prudent
9 and cost-effective way for the Company to meet its Minnesota SES
10 requirements, and has recommended that the MPUC approve the portfolio.
11 If the MPUC finds the Geronimo project in the public interest in the CAP
12 proceeding, we have recommended that only two of the PPAs that makeup
13 the Solar Portfolio proceed, so that the total amount of utility-scale solar
14 additions to our system remains at 187 MW.
15

16 Should the MPUC direct us to move forward with the Geronimo solar
17 project, we will file an application for an ADP with the Commission to
18 provide the Commission an opportunity to asses the prudence of that project
19 consistent with the circumstances surrounding it at that time. We will also
20 update this Application should undertaking the Geronimo solar project impact
21 our proposed 187 MW Solar Portfolio power purchase.
22

23 VI. CONCLUSION

24

25 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

26 A. The 187 MW Solar Portfolio is a cost-effective way for the Company to meet
27 its Minnesota SES requirements at modest cost while adding clean, carbon-

1 free capacity and energy to the integrated system. The addition of this solar
2 capacity provides a hedge against volatile fuel prices, and the clean nature of
3 this resource provides a hedge against future environmental regulation.
4 Consequently, when viewed as a whole, the Company respectfully requests the
5 Commission finds the 187 MW Solar Portfolio resource addition prudent.

6

7 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

8 A. Yes, it does.

Laura McCarten

Experience	2008-Present	Xcel Energy	Minneapolis, MN
	Regional Vice President, NSPM		
	<ul style="list-style-type: none"> ▪ For Xcel Energy's North Dakota service territory, responsible for regulatory and legislative interface and strategies, customer and community relations and public affairs, gas business development, and provide strategic leadership on initiatives to effectively serve customers. ▪ For Xcel Energy's Minnesota service territory, responsible for managing relationships with communities and large customer accounts, gas business development and our HomeSmart service. ▪ For Xcel Energy's South Dakota service territory, responsible for regulatory and legislative interface and strategies, customer and community relations and public affairs, and provide strategic leadership on initiatives to effectively serve customers. 		
	2006-2008	Xcel Energy	Minneapolis, MN
	Director, Regional Transmission Development		
	1997-2005	Xcel Energy	Minneapolis, MN
	Director, Minnesota Community Services		
	1994-1997	Xcel Energy	Mankato, MN
	Regional General Manager		
	1992-1994	Northern States Power	Minneapolis, MN
	Manager, Regulatory Affairs		
	1979-1991	Northern States Power	Minneapolis, MN
	Nuclear Generation: Spent Nuclear Fuel Project Manager, Engineer		
Education	1979	University of Wisconsin	Madison, WI
	Bachelor of Science in Nuclear Engineering		
Professional Development	<ul style="list-style-type: none"> ▪ Xcel Energy Leadership Advantage Program (2004) ▪ University of Michigan Business School, Strategic Marketing Planning (1998) ▪ University of Minnesota, Carlson School of Management, Minnesota Management Institute (1996) 		
Community Service	<ul style="list-style-type: none"> ▪ Lignite Energy Council, Board of Directors ▪ Minneapolis Regional Chamber of Commerce, Board of Directors ▪ North Central Electrical League, Board of Directors ▪ Ordway Center for the Performing Arts, Board of Directors ▪ University Enterprise Laboratories, Board of Directors 		

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Direct 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-_____
Exhibit ____ (KJH-1)

Resource Planning Testimony

November 7, 2014

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MN Solar I Power Purchase Agreement	Trade Secret Schedule 4
North Star Solar Power Purchase Agreement	Trade Secret Schedule 5

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I. INTRODUCTION AND QUALIFICATIONS

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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., the service company subsidiary of Xcel Energy.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have been employed by Xcel Energy or one of its predecessors for over 30 years and assumed my current position as Managing Director of Resource Planning in 2004. My resume is provided as Exhibit___(KJH-1), Schedule 1

I am responsible for managing the development and implementation of the electric resource plans for all the Operating Companies of Xcel Energy. I also have responsibility for managing the bidding and evaluation processes for acquiring new electric generation resources and for managing the technical analysis for supporting Xcel Energy’s regulatory filings associated with its requests to construct and own new generation facilities. Additionally, I am responsible for directing the analytical support for Xcel Energy’s renewable energy plan filings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present the three solar projects that together constitute our proposed acquisition of 187 MW of solar generation resources for the NSP System:

- *Marshall Solar* – a 62.25 MW project located near Marshall, Minnesota to be developed by NextEra;
- *MN Solar I* – a 24.75 MW project located near Tracy, Minnesota to be developed by juwi solar, Inc.; and

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1 clean energy, the solar energy will provide a hedge against increases in natural
2 gas fuel prices and future environmental regulation.

3

4 Q. PLEASE DESCRIBE THE MINNESOTA SES.

5 A. In 2013, the Minnesota legislature enacted Minnesota Statutes Section
6 216B.1691, subdivision 2f, requiring by the end of 2020 that 1.5 percent of the
7 electricity the Company sells to its Minnesota retail customers be generated by
8 solar power. This is commonly referred to as the Solar Energy Standard, or
9 SES. The Company determined that it would need to add approximately
10 300 MW of solar power to our system by 2020 to meet the Minnesota SES
11 requirement. The statute also sets a goal, rather than a requirement, that 10
12 percent of all retail electric sales in Minnesota be generated by solar energy by
13 2030.

14

15 Q. IS THE SES PART OF MINNESOTA'S RENEWABLE ENERGY STANDARD
16 REQUIRING 30 PERCENT OF THE COMPANY'S RETAIL ELECTRICITY SALES TO BE
17 PROVIDED BY RENEWABLE GENERATION RESOURCES BY 2020?

18 A. No. Minnesota Statutes Section 216B.1691, subdivision 2a(b) requires the
19 Company to have 30 percent of its retail electric sales generated by renewable
20 generation by 2020, with at least 25 percent of the 30 percent provided by
21 wind or solar generation, and the remaining 5 percent provided by other
22 eligible renewable generation technologies. Minnesota Statutes Section
23 216B.1691, subdivision 2f(e) prohibits the Company from using the solar
24 generation that satisfies the SES to also satisfy the 30 percent Renewable
25 Energy Standard, and vice versa. The Company, therefore, has an obligation
26 to have 31.5 percent of its retail customer electricity sales be generated by
27 renewable resources by 2020.

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1

2 Q. HAS THE COMPANY DEVELOPED A PLAN TO COMPLY WITH THE MINNESOTA
3 SES?

4 A. Yes. We estimate that we will need a total of approximately 300 MW of solar
5 capacity to meet the Minnesota SES.

6

7 To meet this, we plan to leverage the economics of large-scale solar systems to
8 keep the cost of compliance as low as possible for our customers. We believe
9 that large-scale solar, such as the 187 MW Solar Portfolio, allows us to capture
10 the value of solar at a much lower cost than distributed solar generation. If
11 implemented, the 187 MW Solar Portfolio will provide almost two-thirds of
12 our estimated solar capacity needs.

13

14 At the same time, we support our customers' interest in distributed generation
15 and will offer new programs in Minnesota and incentives required by
16 Minnesota's solar legislation to help the solar industry develop in Minnesota.
17 At this time, we believe it is reasonable to expect up to one third, or 100 MW,
18 of our solar needs to be met through new customer offerings and solar
19 projects receiving funding through Minnesota's Renewable Development
20 Fund. These new program offerings include a Community Solar Gardens
21 program, new Solar*Rewards program, and the Made in Minnesota program
22 administered by the Minnesota Department of Commerce.

23

24 **III. SOLAR REQUEST FOR PROPOSAL**

25

26 Q. WHAT LEAD THE COMPANY TO ISSUE ITS SOLAR RFP IN 2014?

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1 A. We determined that we should issue an RFP to help ensure that we would
2 have an adequate number of options to consider in the process of adding solar
3 resources to our system to meet the Minnesota SES. Issuing the RFP in 2014
4 would help ensure that any projects selected could meet the December 31,
5 2016 expiration deadline for the 30 percent federal Investment Tax Credit
6 (ITC), since the ITC significantly offsets the development costs for projects
7 eligible for the credit. We believed that by capturing the ITC we could capture
8 more attractive pricing for utility scale solar projects.

9

10 Q. PLEASE DESCRIBE THE COMPANY'S RFP.

11 A. We issued the Solar RFP on April 22, 2014, identifying eligible projects as
12 those based on a photovoltaic solar resource with a nominal AC electrical
13 output of at least five MW, that offered to sell to the Company all energy,
14 associated capacity, ancillary services, and all RECs generated by the project.
15 We used several communication vehicles to provide notice to potential
16 bidders, including key mass media and trade press. We also provided a link to
17 our website where the RFP, model Power Purchase Agreement and standard
18 bidder forms were located. All bids were due by 5:00 P.M. Central Daylight
19 Time on June 20, 2014.

20

21 Q. WHAT WAS THE RESPONSE TO THE RFP?

22 A. Developer response to our RFP was robust. There were 111 proposals
23 totaling over 2,100 MW of solar photovoltaic generating capacity submitted by
24 36 developers. Individual projects ranged in size from 5 MW to 100 MW.
25 Submissions included a number of ownership structures from independently
26 owned and operated facilities to offers of partnerships with the Company.

27

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1 Q. HOW DID THE COMPANY ANALYZE THE PROPOSALS?

2 A. Our Resource Planning department led the evaluation team, logging all bids
3 on a tracking spreadsheet and maintaining the bids in a locked room accessible
4 only by the Company's Resource Planning group. Initial screening identified
5 15 projects, in aggregate totaling 630 MW of generation capacity, submitted by
6 11 companies, each with a levelized energy cost of \$85/MWh or less. Copies
7 of these proposals were then provided to our Transmission, Land and Siting,
8 and Purchased Power staff for further evaluation.

9

10 A significant consideration for any project is its ability to interconnect with the
11 transmission system. Therefore, our Transmission Access group performed a
12 detailed multi-factor review of the status of each project's Midcontinent
13 Independent System Operator, Inc. (MISO) interconnection request and
14 potential transmission requirements. This review identified potential
15 significant issues around transmission interconnection cost and curtailment
16 risk for several of the projects. Based on this analysis, the Transmission
17 Access group recommended that a number of these projects be eliminated
18 from further consideration.

19

20 The results of these evaluations and further due diligence supported the
21 selection of the three projects that are the subject of this Application. The
22 project bids proceeded to Purchase Power Agreement (PPA) negotiations
23 which were successfully completed in late September. The three fully
24 negotiated but unsigned PPAs are included as Trade Secret Schedules 3, 4, and
25 5 to my testimony.

26

27

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1 Q. HOW DID THE COMPANY DOCUMENT THAT ITS RFP PROCESS WAS
2 TRANSPARENT AND UNBIASED?

3 A. To certify that the process used for obtaining and evaluating responses to the
4 RFP was unbiased and provided transparency to help facilitate expeditious
5 review of our Petition, we engaged an independent consultant to perform an
6 audit of the RFP process. The audit was designed to examine whether the
7 process for obtaining and evaluating responses to the RFP was biased. The
8 consultant's report, provided as Trade Secret Exhibit__(KJH-1), Schedule 2 to
9 my testimony, concluded that the Company's RFP process was free from bias
10 and afforded each proposal equitable care and consideration. In addition, the
11 report noted that the process was rigorous, robust and that the Company
12 administered the process professionally and was thorough in its efforts.

13

14 **IV. PROPOSAL TO ACQUIRE THE 187 MW SOLAR PORTFOLIO**

15

16 Q. WHY IS THE COMPANY SEEKING TO ADD THE 187 MW SOLAR PORTFOLIO
17 PROPOSAL?

18 A. Our proposal to add a 187 MW portfolio of solar generation is based on our
19 belief that we should purchase enough solar energy now to comply with
20 Minnesota's 2020 1.5 percent of sales SES while capturing the 30 percent
21 federal ITC.

22

23 Q. WHY HAS THE COMPANY CONCLUDED IT SHOULD BUY ENOUGH SOLAR
24 ENERGY NOW TO MEET THE SES RATHER THAN SPREAD ITS ACQUISITION OF
25 SOLAR RESOURCES OVER TIME?

26 A. As I mentioned previously, the federal ITC of 30 percent represents a
27 significant incentive to developers that results in very attractive pricing for

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1 solar energy at this time. The incentive decreases significantly to 10 percent at
2 the end of 2016, and future federal incentives are increasingly uncertain.
3 These circumstances suggest it is prudent to make a substantial purchase now,
4 so that developers can utilize -- and our customers can benefit from -- the 30
5 percent ITC. That said, we recognize that continuing technology
6 improvements in the solar generation market may result in solar prices that
7 reflect only a 10 percent ITC declining to a level of pricing comparable to
8 these new projects.

9
10 If federal incentives continue, we can make additional purchases to take
11 advantage of those policies. If federal incentives are removed, we will have
12 the flexibility to monitor technology improvements and time further
13 acquisitions accordingly. Therefore, strategically acquiring the 187 MW Solar
14 Portfolio we present in this Application now is a reasonable and prudent way
15 to manage these issues.

16
17 **V. DESCRIPTION OF THE 187 MW SOLAR PORTFOLIO**

18
19 Q. PLEASE DESCRIBE THE MARSHALL SOLAR PROJECT.

20 A. The *Marshall Solar* project will be a 62.25 MW solar energy generation facility
21 on approximately 464 acres in an agricultural area east of Marshall, Minnesota
22 in Lyon County. The project will consist of 30° fixed tilt configuration,
23 photovoltaic modules and will interconnect at the existing Company Lyon
24 County substation at 69 kV.

25
26 Q. WHAT IS THE MARSHALL SOLAR PROJECT'S CONSTRUCTION SCHEDULE?

27 A. The bulk of construction of the *Marshall Solar* project is expected to begin in

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1

2 Q. WHAT ARE THE TERMS OF THE MN SOLAR I PPA?

3 A. We have negotiated a 25-year PPA with juwi solar, Inc. to purchase all of the
4 electric energy produced at *MN Solar I*. The purchase price of electric energy
5 from *MN Solar I* starts at [TRADE SECRET BEGINS...

6 ...TRADE SECRET ENDS]. We calculate the
7 levelized cost of energy over the term of the Agreement to be [TRADE
8 SECRET BEGINS... ...TRADE SECRET ENDS].

9

10 Q. PLEASE DESCRIBE THE NORTH STAR SOLAR PROJECT.

11 A. *North Star Solar* is a 100 MW solar energy generation facility located on
12 approximately 800 acres in an agricultural area southeast of North Branch,
13 Minnesota in Chisago County. *North Star Solar* will consist of single axis
14 tracking panels. The project plans to interconnect at 115kV to the existing
15 NSP Chisago County Substation.

16

17 Q. WHAT IS THE NORTH STAR SOLAR PROJECT'S CONSTRUCTION SCHEDULE?

18 A. As with the other two projects, the construction schedule is designed so that
19 the project will qualify for the 30 percent federal ITC to offset project
20 construction costs. Engineering, procurement and some construction will
21 occur in 2015, with the bulk of construction of the *North Star Solar* project
22 expected to begin in spring 2016.

23

24 Q. WHAT ARE THE TERMS OF THE NORTH STAR SOLAR PROJECT'S PPA?

25 A. The purchase price of electric energy under the 25-year PPA with *North Star*
26 *Solar* starts at [TRADE SECRET BEGINS...

27 ...TRADE SECRET ENDS]. We calculate the levelized cost of

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1 energy over the term of the Agreement to be [TRADE SECRET
2 BEGINS... ...TRADE SECRET ENDS].

3
4 **VI. PROJECT RISK MANAGEMENT**

5
6 Q. PLEASE DESCRIBE WHAT PROJECT RISK MANAGEMENT REFERS TO.

7 A. As with the acquisition of any new resource addition for our system, there are
8 risks associated with the projects comprising the 187 MW Solar Portfolio. We
9 believe that we have identified, assessed, and mitigated major risks through
10 prudent contracting practices, and that it is reasonable and in our customers'
11 interests for the Commission to find the projects are prudent additions to the
12 integrated NSP System.

13
14 Q. WHAT RISKS DID THE COMPANY IDENTIFY?

15 A. Risks fall into two general categories, development risks and operational risks.
16 Development risks for solar projects include project financing, construction,
17 transmission, and environmental issues. Operational risks include energy
18 production levels, curtailment, and breaches in performance obligations.

19
20 Q. PLEASE DESCRIBE THE FINANCING RISK.

21 A. The principal financing risk involves the projects qualifying for the federal
22 ITC. In 2008, the 30 percent ITC for solar projects was extended and now
23 expires on December 31, 2016. We believe these projects will meet the
24 requirements necessary to qualify for the ITC, and that the risk has been
25 reasonably mitigated in the relevant agreements. In the Agreements, each
26 developer assumes the risk of qualifying for the ITC, and the failure to qualify
27 for the ITC will not result in any price increase or other increased liability for

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1 us or our customers

2

3 Q. WHAT ARE THE CONSTRUCTION RISKS?

4 A. By contracting only for the output of *Marshall Solar*, *MNSolar I*, and *North Star*
5 *Solar*, the Company has fully-shifted the risks of development and
6 construction to the developers. In the PPAs for all three projects, the parties
7 have provided for pre- and post-COD security funds as follows:

8 **[TRADE SECRET BEGINS...**

9

10

11

12

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14

15

...TRADE SECRET ENDS]

16 In addition, we have provided for the payment of liquidated damages for each
17 day the projects fail to meet their Commercial Operation Milestone.

18

19 Q. WHAT IS THE TRANSMISSION RISK?

20 A. There are two aspects of the transmission risk: (1) transmission
21 interconnection; and (2) capacity accreditation.

22

23 Q. PLEASE DESCRIBE THE TRANSMISSION INTERCONNECTION RISK.

24 A. As with many PPAs, the interconnection arrangements have not been
25 finalized. As a result, the PPAs for the 187 MW Solar Portfolio contain a
26 condition precedent that permits the developer to terminate the agreement if
27 it is unable to obtain an interconnection agreement by a certain date. In
28 addition, the *North Star Solar* agreement permits the developer to terminate the
29 agreement if the interconnection costs it must bear are materially greater than

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1 its budgeted projections. In any event, our risks are mitigated because all
2 three PPAs provide for the developer to bear all interconnection costs. In
3 addition, all three projects are located close to the proposed point of
4 interconnection to the transmission system with a relatively strong network of
5 transmission facilities in the vicinity, so we do not anticipate any significant
6 transmission improvements will be necessary for direct interconnection.

7
8 The *Marshall Solar* and *MN Solar I* projects are interconnected at or near the
9 Lyon County substation, which now has connections to the new Brookings
10 County to Twin Cities 345 kV transmission line. Lyon County Substation also
11 has a 345 kV connection to Minnesota Valley and the existing 230 kV line to
12 the Twin Cities along with several 115 kV and 69 kV lines.

13
14 The *North Star Solar* project will interconnect to the Chisago Substation just
15 north of the Twin Cities. The Chisago Substation is connected to the metro
16 area through two major 345 kV transmission lines and several 115 kV
17 transmission lines. The Chisago Substation also has a connection to the
18 Dorsey to Forbes to Chisago 500kV transmission line between Manitoba
19 Canada and the Twin Cities.

20
21 Q. PLEASE DESCRIBE THE CAPACITY ACCREDITATION RISK.

22 A. As I describe further below, we currently predict that the 187 MW Solar
23 Portfolio will receive approximately 52 percent capacity accreditation in
24 around 2018. However, in order for the projects to contribute creditable
25 capacity toward our resource adequacy calculation, MISO requires generators
26 to achieve unconditional interconnection status. Under the current MISO
27 generator interconnection and resource adequacy requirements, generators

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1 with conditional Generator Interconnection Agreements (GIAs) will not be
2 eligible for capacity accreditation until all upgrades required under the
3 project's GIA are complete and in-service. Over the past several years GIAs
4 for projects located in the Minnesota area have been conditioned upon the
5 completion of various MISO Multi-Value Projects including the North La
6 Crosse to Madison 345 kV line – which has a planned in service date of
7 December 2018.

8
9 If the solar projects have GIAs that are conditional on this line, and the line
10 goes into service as scheduled, the solar projects would not be eligible to
11 qualify as capacity resources until the MISO 2019/2020 planning year. MISO
12 is aware of this concern and is working with its stakeholders to identify ways
13 for conditional GIAs to qualify as capacity resources.

14
15 Q. WHAT IS THE ENVIRONMENTAL RISK?

16 A. Under all three PPAs, we will own all environmental and renewable energy
17 credits and attributes of the facilities. In addition, the developers are
18 responsible for all applicable environmental permits, licenses and approvals
19 from any governmental authority required under applicable laws for
20 construction, ownership, operation and maintenance of the facilities.

21
22 Q. PLEASE DESCRIBE THE RISK ASSOCIATED WITH ENERGY PRODUCTION.

23 A. All three PPAs require their respective projects to deliver a defined level of
24 Committed Solar Energy (CSE) in each commercial operation year. If a
25 project fails to achieve 85 percent of the CSE during an annual Measurement
26 Period, the Seller has 30 days to cure the failure, or if such cure cannot
27 reasonably be effected within 30 days, the Seller must commence the cure

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1 within 30 days and then diligently pursue such cure to completion as soon as
2 practicable thereafter. The Seller’s efforts to cure the failure to deliver the
3 CSE must result in the project delivering more than 85 percent of the CSE
4 during the subsequent annual Measurement Period.

5

6 Q. WHAT IS THE RISK ASSOCIATED WITH CURTAILMENT?

7 A. Under each PPA, we may curtail the production from the project for any
8 reason at our sole discretion, and need not pay any curtailment payments if the
9 curtailment occurs for the following reasons: Seller’s failure to deliver to Point
10 of Delivery; an emergency; curtailment directive(s) from the Transmission
11 Provider or Market Operator pursuant to the Interconnection Agreement;
12 planned or unplanned maintenance and/or testing outages of the transmission
13 system; Seller’s failure to maintain or respond to Automatic Generation
14 Control Instructions; or, Seller’s failure to maintain permitting.

15

16 We do not expect that the solar projects will experience significant levels of
17 curtailment or unreasonable Locational Marginal Price differentials between
18 the solar projects and NSP load. The solar projects are more peaking
19 daytime-only resources that will not compete with wind for transmission
20 capacity, since wind generation also occurs during off peak periods with a
21 tendency of higher output levels during this period.

22

23 In addition, the solar projects are smaller than the many wind projects, and are
24 located in areas with significant transmission infrastructure that provides
25 sufficient outlet to accommodate the solar generation and are interconnected
26 to transmission facilities that have strong electrical ties to the Company’s load
27 in the Twin Cities metro area.

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2 Q. HOW ARE THE RISKS ASSOCIATED WITH BREACHES IN PERFORMANCE
3 OBLIGATIONS MITIGATED?

4 A. The PPAs include protective measures and remedies such as: specific
5 performance; step-in rights; the right to terminate the agreement upon the
6 occurrence of certain events; and the ability to seek damages or upon
7 termination for breach.

8

9 **VII. EVALUATION OF THE 187 MW SOLAR PORTFOLIO**

10

11 Q. HOW DID THE COMPANY EVALUATE THE 187 MW SOLAR PORTFOLIO?

12 A. The Company performed two evaluations of the 187 MW Solar Portfolio: a
13 quantitative analysis and a qualitative analysis. Based on the outcome of these
14 analyses, we determined that the acquisition of the 187 MW Solar Portfolio is
15 a prudent resource acquisition to allow us to cost effectively meet our
16 Minnesota SES requirements while providing a source of clean energy that has
17 key fuel and environmental hedging benefits. In addition, while solar
18 generation is primarily a source of clean energy, it also provides some
19 additional capacity to the system that can be used to offset future capacity
20 needs.

21

22 To perform the quantitative analyses, we used the Strategist resource planning
23 model, and present the results in Present Value Revenue Requirements
24 (PVRR) terms, excluding any assumptions regarding the future cost of carbon
25 dioxide (CO₂) or externalities as required by North Dakota law. Strategist
26 simulates the operation of the NSP System, and estimates the total cost of
27 energy over the life of the projects on a present value basis. We also use the

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1 model to test results under a range of input assumptions. To assess the
2 impact on customer costs, we simulated the operation of the NSP System with
3 and without the addition of the 187 MW Solar Portfolio.

4
5 We also performed a more qualitative analysis to identify the non-economic
6 benefits of the 187 MW Solar Portfolio to the NSP System. When the
7 quantitative analysis and the qualitative analysis are taken together, the 187
8 MW Solar Portfolio will add a relatively minor net cost to the NSP System,
9 but provide material qualitative benefits which demonstrate the prudence of
10 this resource addition.

11
12 **A. Quantitative Analysis**

13
14 Q. WHAT ARE THE RESULTS OF THE QUANTITATIVE ANALYSIS OF THE 187 MW
15 SOLAR PORTFOLIO?

16 A. Our Reference Case analysis estimates that the cost of energy from the 187
17 MW Solar Portfolio over the 25-year term of the PPAs, without considering
18 any CO2 or externality costs, is approximately \$14 million on a PVRR basis,
19 or approximately \$5.19 on a levelized per MWh basis. We also analyzed the
20 impact of adding the 187 MW Solar Portfolio to the system under various
21 sensitivities, including a scenario where natural gas prices stay below our
22 current market forecasts, a scenario where the system cannot make market
23 purchases to meet increasing demand (Markets Off), and scenarios when
24 capacity factors of the 187 MW Solar Portfolio are higher or lower than
25 expected.

26
27 Table 1 below presents the results of these sensitivity tests. The table shows

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1 the cost to the system to operate *without* the 187 MW Solar Portfolio (the
2 Reference Case), and also shows that the operating the system *with* the 187
3 MW Solar Portfolio under the various sensitivities uniformly results in a
4 relatively negligible net cost. Table 2 below presents the results of our Base
5 Case analysis on a levelized \$/MWh basis.

6
7

Table 1: Strategist PVRR Analysis

	Base	Low Gas	Markets Off	+2.5% Capacity Factor	-2.5% Capacity Factor
Base Case (No Solar)	\$49,030	\$46,192	\$49,747	\$49,030	\$49,030
Full Portfolio	\$49,044	\$46,235	\$49,742	\$49,055	\$49,036
	\$14	\$43	(\$5)	\$25	\$6

8
9

10 The Markets Off case indicates a \$5 PVRR savings that reflects the impact of not
11 having the availability/benefit of market energy purchases.

12
13

Table 2: Levelized Cost Analysis

	RFP Portfolio
PPA Price	\$73.20
Avoided Fossil Fuel	(\$53.16)
Capacity Credit	(\$14.86)
Net Cost (Savings)	\$5.19

14

15 Q. WHAT BENEFITS WILL THESE SOLAR PROJECTS BRING TO NORTH DAKOTA
16 CUSTOMERS?

17 A. As identified in Table 2, the largest benefit of the proposed solar projects to
18 North Dakota customers is the displacement of future fuel and other energy

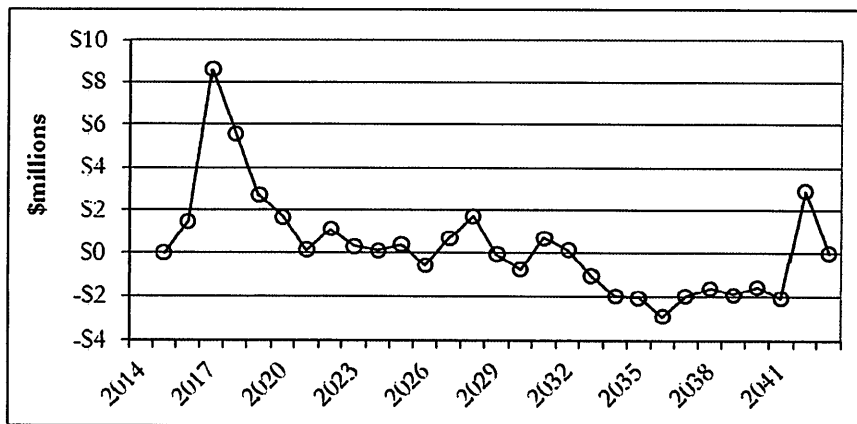
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1 purchases. Over 70 percent of the benefit of the solar resources is to reduce
2 future purchases of natural gas, coal and market energy purchases. Since these
3 solar resources are primarily energy resources, the value of displacing future
4 capacity requirements is less than 20 percent of the total cost of the proposed
5 new purchases.
6

7 Q. HOW IS THE IMPACT OF ADDING THE 187 MW SOLAR PORTFOLIO TO THE NSP
8 SYSTEM SPREAD OVER TIME?

9 A. Figure 1 below illustrates the annual net costs/benefits associated with the
10 187 MW Solar Portfolio that lead to the \$14 million PVRR impact calculation.
11 As shown, over the 25-year term of the PPAs, the 187 MW Solar Portfolio
12 moves from net cost to net savings, which is due to the net effect of the
13 expected deterioration of the solar panels making up the 187 MW Solar
14 Portfolio, and therefore less generation from these resources, while they are
15 also displacing what is expected to be an increasing cost of fossil fuel when
16 compared to the fixed price of the PPAs.
17

18 **Figure 1: Annual Impact of 187 MW Solar Portfolio**



19
20
21

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1 Q. ON WHAT IS THIS ANALYSIS BASED?

2 A. Our quantitative analysis is based on the cost of electricity displaced by the
3 187 MW Solar Portfolio as well as the accredited capacity value of this
4 resource.

5

6 The NSP System is dispatched by the MISO. MISO generally dispatches solar
7 production ahead of other generation such as natural gas and coal-based
8 generation. Consequently, the more solar energy produced, the less other
9 fossil generation is operated and the less fossil fuel must be purchased.
10 Therefore, when the energy from solar resources is produced, it displaces a
11 similar amount of fuel that would have been acquired by the Company or
12 other purchases of market energy. Our Base Case assumes a displacement of
13 fuel that would have been purchased to generate approximately 370,000 MWh
14 of fossil generation, accounting for the majority of differences in cost of
15 system operation with and without the addition of the 187 MW Solar
16 Portfolio.

17

18 Additionally, the 187 MW Solar Portfolio we propose in this Application will
19 provide accredited capacity starting in June 2018. We expect the 187 MW
20 Solar Portfolio to receive an approximately 52 percent capacity accreditation
21 under MISO rules, or about 100 MW of accredited capacity. Under current
22 MISO rules, the solar projects would not be able to qualify as a capacity
23 resource until the MISO 2018/2019 planning year (June 1, 2018 through May
24 31, 2019).

25

26 The solar projects are required to provide MISO with a minimum of 30
27 consecutive days' of historical data during June, July or August for the hours

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1 of 1500 – 1700 EST in order to be eligible to participating in the MISO
2 Planning Reserve Auction (PRA) that takes place in March of every year. The
3 earliest that this data could be collected would be during June, July or August
4 of 2017 since the solar projects are scheduled to go into service in December
5 2016. Obtaining the data in 2017 would allow the projects to participate in
6 the March 2018 PRA for the 2018/2019 planning year. For purposes of the
7 economic evaluation, we assumed the projects will receive capacity
8 accreditation for the 2018/2019 planning year. I discuss the impacts of these
9 capacity accreditation on the Company’s Resource Planning later in my Direct
10 Testimony.

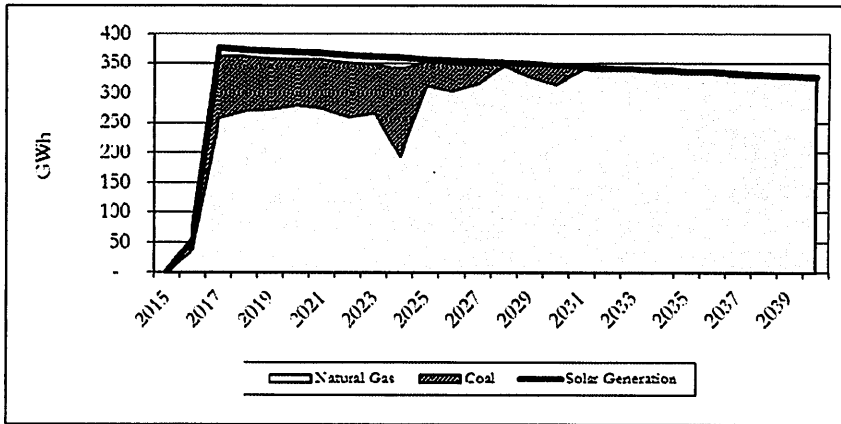
11
12 Q. FOR CONTEXT, WHAT IS THE MIX OF ENERGY THAT IS DISPLACED BY THE 187
13 MW SOLAR PORTFOLIO?

14 A. Figure 2 below illustrates the results of the Strategist dispatch simulations
15 under the Markets Off scenario, that is, Strategist only allows increasing
16 customer demand to be met by NSP System resources, not by purchases of
17 energy from the market. In this scenario, the majority of the solar generation,
18 approximately 88 percent, displaces natural gas purchases, with the remaining
19 expected to displace coal purchases. This reflects the fact that during on peak
20 periods more gas generation is dispatched to meet on peak conditions as
21 compared to off peak periods when much less gas generation is needed.

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Figure 2: Displaced Generation (Markets Off)



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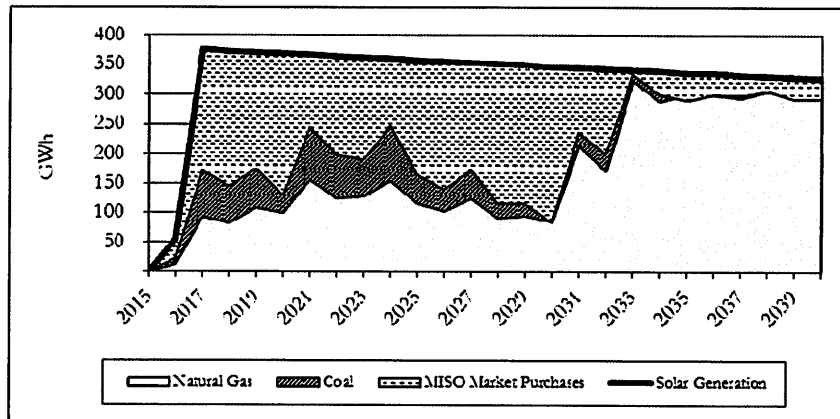
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Figure 3 below illustrates the results of the Strategist dispatch simulations in a “Markets On” scenario, where Strategist may choose to purchase market energy to meet system needs. In this scenario, approximately 53 percent of the solar generation displaces natural gas purchases, 9 percent displaces coal purchases, and 37 percent displaces the purchase of market energy.

Figure 3: Displaced Generation (Markets On)



11

12

13

14

Q. WHAT IS THE ESTIMATED RATE IMPACT ON THE COMPANY’S NORTH DAKOTA CUSTOMERS?

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1 A. While the 187 MW Solar Portfolio represents the largest utility solar energy
2 acquisition we have made, we estimate that the customer rate impacts will be
3 minor, because the NSP System is so large in comparison. In fact, we expect
4 that soon after initial operation, customers’ overall bills will go from being
5 slightly higher to gradually reducing to a net increase by 2025 of about 0.015¢
6 per kWh. Applying this to average residential usage of 750 kWh per month
7 would amount to about \$0.15/month in 2017, dropping to \$0.12/month by
8 2025.

9
10 As shown in Table 4 below, our Strategist dispatch simulation forecasts that
11 for most years the rate impact of the 187 MW Solar Portfolio will be nearly
12 offset by decreases in the cost of fossil fuel and other purchased energy.

13
14 **Table 4: Customer Impacts**

	2015	2016	2017	2018	2019	2020
Base Rates	0 000¢/kWh	0 000¢/kWh	0 000¢/kWh	0 000¢/kWh	0 000¢/kWh	0 000¢/kWh
Fuel Clause	0 000¢/kWh	0 008¢/kWh	0 054¢/kWh	0 055¢/kWh	0 055¢/kWh	0 056¢/kWh
Avoided Fuel & Purchased Power	0 000¢/kWh	-0 004¢/kWh	-0 034¢/kWh	-0 035¢/kWh	-0 035¢/kWh	-0 039¢/kWh
Net Rate Impact	0.000¢/kWh	0.003¢/kWh	0.020¢/kWh	0.020¢/kWh	0.020¢/kWh	0.017¢/kWh

	2021	2022	2023	2024	2025
Base Rates	0 000¢/kWh	0 000¢/kWh	0 000¢/kWh	0 000¢/kWh	0 000¢/kWh
Fuel Clause	0 057¢/kWh	0 057¢/kWh	0 058¢/kWh	0 059¢/kWh	0 060¢/kWh
Avoided Fuel & Purchased Power	-0 042¢/kWh	-0 041¢/kWh	-0 043¢/kWh	-0 044¢/kWh	-0 044¢/kWh
Net Rate Impact	0.014¢/kWh	0.016¢/kWh	0.015¢/kWh	0.015¢/kWh	0.015¢/kWh

15
16
17 **B. Qualitative Analysis**

18
19 Q. WHAT QUALITATIVE BENEFITS DOES THE 187 MW SOLAR PORTFOLIO
20 PROVIDE?

21 A. The addition of the 187 MW Solar Portfolio provides qualitative benefits,

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1 because is acts as a hedge against higher natural gas prices and future
2 environmental regulations through the displacement of natural gas- and coal-
3 based generation. If the Company were not to acquire these resources, future
4 levels of natural gas consumption and MISO market purchases would be
5 higher, creating higher cost uncertainty for our customers.

6

7 Q. HOW DOES THE 187 MW SOLAR PORTFOLIO PROVIDE THESE QUALITATIVE
8 BENEFITS?

9 A. As I mentioned, the 187 MW Solar Portfolio will displace the purchase of
10 fossil fuel, including fuel for gas-fired generation, as well as market purchases
11 and replaces it with fixed price clean energy. Displacement of this generation
12 by the 187 MW Solar Portfolio provides qualitative benefits to the NSP
13 System and therefore to our customers.

14

15 More specifically, we expect that the 187 MW Solar Portfolio will provide
16 almost 9,000 GWh of carbon-free energy over the life of their PPAs,
17 displacing almost six million tons of carbon emissions. This will reduce our
18 exposure to future environmental regulation and will lower the cost of
19 compliance.

20

21 Additionally, the displacement of variable cost fossil-based and market energy
22 with a fixed price energy source provides a commodity hedge against volatile
23 gas process and market risk. The fixed price certainty provides an additional
24 qualitative benefit to our customers.

25

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VIII. IMPACT ON RESOURCE ADEQUACY

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Q. WILL THE PROPOSED 187 MW RESOURCE ACQUISITION AFFECT THE COMPANY'S NEED FOR ADDITIONAL CAPACITY RESOURCES IN THE 2017-2019 TIMEFRAME AS DISCUSSED IN CASE NOS. PU-13-194 AND PU-13-195?

A. The first year that MISO will recognize any capacity accreditation of the 187 MW Solar Portfolio is the 2018/2019 planning year. As a result, the 187 MW Solar Portfolio will likely have a minimal or no impact on our need for capacity resources in the 2017 to 2019 time frame.

As the Commission is also aware, the Minnesota Public Utilities Commission (MPUC) opened a competitive acquisition process to select the resource(s) to meet the Company's identified capacity need (MPUC Docket No. E002/CN-12-1240).

MISO's Planning Reserve Margin calculation is relatively new and the Company had some reservation about whether the new methodology and associated calculation used by MISO would remain stable. Since then, we have gained more confidence in the approach and believe it represents a conservative estimate of our reserve obligations.

Q. WHAT IS THE STATUS OF THE COMPETITIVE RESOURCE ACQUISITION DOCKET?

A. On December 31, 2013, the ALJ issued his report recommending the MPUC select Geronimo Energy's 100 MW Aurora solar project. Exceptions to and comments on the ALJ report were filed by all the parties, and the MPUC heard oral argument on the exceptions and comments at a hearing held March

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1 25 and 27, 2014.

2

3 In an order issued May 23, 2014, the MPUC determined that the Company
4 should work with Calpine, Invenergy and Geronimo to develop the terms of
5 the respective PPAs for the MPUC to evaluate the contract terms as part of its
6 final decision. The MPUC also ordered the Company to update its cost
7 estimate for Black Dog Unit 6, as necessary.

8

9 The Company negotiated with the three counterparties over June, July, and
10 August 2014. On September 23, 2014, we filed the draft contracts we
11 negotiated with Geronimo, Calpine, and Invenergy, and informed the MPUC
12 that we did not need to update our estimated costs for Black Dog Unit 6. We
13 also updated our need assessment as part of that filing, which indicated that
14 our capacity need has been pushed out to 2019.

15

16 Q. WHAT ARE THE NEXT STEPS IN THE PROCEEDING?

17 A. We anticipate the MPUC will set a hearing to consider this matter in early
18 December 2014. The issue before the MPUC will be whether it recommends
19 that the Company move forward with any or none of the four resources that
20 are before it.

21

22 Q. WHAT IMPACT WOULD THE MPUC'S SELECTION OF THE 100 MW GERONIMO
23 AURORA SOLAR PROJECT IN THE COMPETITIVE ACQUISITION PROCESS HAVE
24 ON THE COMPANY'S ACQUISITION OF THE 187 MW SOLAR PORTFOLIO?

25 A. Selection of the Geronimo proposal in the competitive acquisition process
26 docket does not necessarily have any impact on our 187 MW Solar Portfolio;
27 both could move forward. In the event that the Company moves forward

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1 with the Geronimo solar project, we will file an application for an ADP with
2 the Commission to provide the Commission an opportunity to assess the
3 prudence of the project consistent with the circumstances surrounding it at
4 that time. We will also update this Application should undertaking the
5 Geronimo solar project impact our acquisition of the 187 MW Solar Portfolio.
6

IX. CONCLUSION

7
8
9 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

10 A. The Company's proposed acquisition of the 187 MW Solar Portfolio is based
11 on our belief that we should purchase enough solar energy now to comply
12 with Minnesota's 2020 1.5 percent of sales SES while capturing the 30 percent
13 federal ITC. Additionally, acquisition of these resources will provide the NSP
14 System with an additional source of clean energy that will displace other fuel
15 and energy purchases. The 187 MW Solar Portfolio results in a relatively
16 minor cost impact to NSP System customers, which when balanced by
17 qualitative benefits such as providing a natural gas price hedge, acquisition of
18 these resources to meet our Minnesota SES obligations is prudent.
19

20 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

21 A. Yes, it does.

Kurtis J. Haeger

Statement of Qualifications

I graduated from the University of Colorado, Boulder, in 1982 with a Bachelor of Science Degree in Civil Engineering and from the University of Colorado, Denver, in 1987, with a Master of Business Administration in Finance.

I began my employment with Public Service Company of Colorado in June 1982, as a Gas Distribution Engineer. In June 1988, I was promoted to Supervisor, Gas Utilization and Testing. In May 1990, I was promoted to System Planning & Forecasting Manager, and, in October 1994, I was promoted to Gas Supply and Planning Manager. Upon the merger between Public Service Company of Colorado and Southwestern Public Service Company in August 1997, I assumed the same position with New Century Services, Inc., the service company subsidiary of New Century Energies, Inc. In March 1999, I assumed the position of Director, Gas Business Support. Upon the merger between New Century Energies, Inc. and Northern States Power Company in August 2000, I was appointed to the position of Director, Gas Supply and Supply Planning for Xcel Energy Services Inc. In May 2004, I was promoted to the position of Managing Director, Resource Planning, the position I currently hold.

Since 1990, my responsibilities have included the development of forecasts of annual and daily gas requirements, long term price of gas forecasts, cost of gas budgets, business planning, strategic planning, long range gas supply planning and gas integrated resource planning, gas supply purchasing, the purchasing of gas transportation and storage services and electric resource planning for Public Service Company, Northern States Power Company and Southwestern Public Service. In my present position, I am

responsible for the resource planning and for the acquisition and bidding activities for electric generation on all of our electric systems.

I have presented testimony before the Colorado Public Utilities Commission in Docket Nos. 93A-561G, 94A-447G, 93S-001EG (95I-394G), 02A-267G, 98S-518G, 00A-415G, 97A-622G, 99A-549E, 00A-415G, 01A-181E, 02A-267G, 02S-315EG, 02A-541E, 03A-489EG and Application No. 34815. I have also sponsored testimony before the Federal Energy Regulatory Commission in Colorado Interstate Gas Co.'s rate case Docket Nos. RP93-99 and RP96-190, Northern Natural Gas Co.'s rate case Docket No. RP03-398 and before the Wyoming Public Service Commission, the North Dakota Commission, the Minnesota Commission and the Texas Commission in various electric and rate case proceedings.

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

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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

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 Managing Director of Resource
5 Planning for Xcel Energy Services Inc. (XES), the service company subsidiary
6 of Xcel Energy Inc. In that role I coordinate the resource planning function
7 for Northern States Power Company-Minnesota (NSP, Xcel Energy or the
8 Company).

9
10 Q. HAVE YOU PROVIDED OTHER TESTIMONY ON THE TOPICS YOU ARE
11 PROVIDING HERE?

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

17
18 I also submitted prefiled written Direct Testimony on February 13, 2015 in
19 Case No. PU-15-095 (the Geronimo Solar PPA proceeding). My testimony in
20 the Geronimo Solar PPA proceeding provides additional information about
21 the Company's resource planning efforts and describes NSP's views on the
22 desirability to plan conservatively to ensure sufficient generating capacity is
23 and reasonable-cost energy in place to meet our customers' needs under all
24 reasonable circumstances. In addition, that testimony provides discussion
25 about the generation resource "Restack" concept, which arose in our
26 settlement of the last rate case (Case No. PU-12-813) and which is currently
27 being negotiated by the Company and Commission Staff.

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

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

11

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

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

20

21 Q. PLEASE ELABORATE.

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

27

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 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.

