



**BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

***In the Matter of Northern States Power Company's
Advance Determination of Prudence
For its Solar Portfolio
Case No. PU-14-810***

**DIRECT TESTIMONY
OF
MIKE DILLER**

**ON BEHALF OF THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION
ADVOCACY STAFF**

February 20, 2015

Table of Contents

Q: Provide your name and qualifications.....	1
Q: What is the purpose of your testimony?	1
Q: Please summarize your testimony.....	1
Q: How did you determine that the solar portfolio is not needed?	2
Q: Isn't it better to have excess generation?	2
Q: How has resource adequacy changed in recent years?	3
Q: Does the PRM account for outages and undeliverable power?	3
Q: How is the planning reserve margin calculated?	4
Q: Does the diversity of MISO minimize the need for capacity?	4
Q: Provide context for the size of MISO.	4
Q: Is there a cost to carry excess generation?	5
Q: Who benefits if NSP adds excess generation?.....	6
Q: When should excess generation resources be deployed?.....	6
Q: Can NSP incur a penalty for failing to plan for enough generation?	6
Q: Does MISO assess penalties for forced outages?	7
Q: If there is no financial or operational need for the Solar Portfolio, how does NSP justify its proposal?	7
Q: Should the NDPSC consider the MN Solar Energy Standard?	8
Q: How does denying an ADP benefit NSP and MN?	9
Q: How does the MN RPS compare to other states?	9
Q: Should NSP invest now to take advantage of the 30% ITC?	10
Q: Is the SP price comparable to the market price of energy?	10
Q: How does the SP compare to current wind energy prices?	10
Q: Will better opportunities occur for deploying solar?	11
Q: Should the NDPSC consider the value of solar energy as a hedge against future environmental regulation.	11
Q: Does the SP provide a hedge against natural gas prices?.....	13
Q: Should the NDPSC consider the smallness of the SP's rate impact?	14
Q: Should the NDPSC deny recovery of replacement capacity?	14
Q: Does this conclude your testimony?	15
Appendix – Acronyms Used in Testimony	16

1 Q: **Provide your name and qualifications.**

2 A: My name is Mike Diller. I am the Director of Economic Regulation for the
3 North Dakota Public Service Commission (NDPSC). I am a utility analyst and
4 provide direction to a small staff. I have 30 years of utility regulatory
5 experience including service to both the Oklahoma Corporation Commission
6 and the NDPSC.

7 I received a Bachelor of Science Degree in Accounting from Oklahoma
8 Christian College in Edmond, Oklahoma in 1981. I am a Certified Public
9 Accountant and member of the American Institute of Certified Public
10 Accountants. I have testified before the NDPSC on numerous occasions
11 including acquisition and merger proposals, rate cases, settlements, advance
12 determination of prudence requests and rule changes.

13
14 Q: **What is the purpose of your testimony?**

15 A: The NDPSC has appointed me to advocacy staff (staff) in this proceeding. As
16 such, I will provide the NDPSC with an analysis of Northern States Power
17 Company's (NSP) application for Advance Determination of Prudence (ADP)
18 for its proposed Solar Portfolio (SP).

19

20 Q: **Please summarize your testimony.**

21 A: NSP's North Dakota ratepayers do not need the proposed SP for generation
22 capacity or the energy that these units would provide. The proposal does not
23 represent least cost planning. Instead, the SP is being proposed to satisfy
24 Minnesota's Solar Energy Standard (SES). Staff recommends that the
25 NDPSC deny the requested ADP and also deny any replacement costs for
26 the denied capacity.

27

1 **Q: How did you determine that the solar portfolio is not needed?**

2 A: Staff compared NSP's most recent load forecasts to the capacity of its
3 existing generation resources noting that NSP is able to meet its load
4 obligations without any additional generation facilities until 2024.¹

5

6 For the few years between now and 2024 when resource adequacy is
7 projected to be tight, NSP provided low cost alternatives to the Minnesota
8 Public Utilities Commission (MPUC) including increasing its diversity
9 exchange agreement with Manitoba Hydro by 75 MW and extending the lives
10 of its oil-fired peaking units at Blue Lake.²

11

12 In its Reply Comments to the Comments filed by other parties to the
13 Competitive Resource Acquisition Process (CAP) before the MPUC, NSP
14 indicates that a generation surplus is projected to continue through 2023,
15 even when excluding the proposed utility-scale solar generation.³

16

17 Despite NSP's comments, the MPUC approved or is expected to approve the
18 construction of the following generation resources (UCAP ratings):

19

- 72 MW Geronimo Aurora solar PPA (2018 in-service date);
- 308 MW Calpine Mankato combined cycle PPA (2019);
- 207 MW Black Dog unit #6 combustion turbine (2020);
- 73 MW Manitoba Hydro diversity exchange agreement (June, 2016);
- 98 MW from the Solar Portfolio (End of 2016).⁴

20

21

22

23

24

25 **Q: Isn't it better to have excess generation?**

26 A: NSP already carries excess generation via its planning reserve margin to
27 account for catastrophic events and unforeseen outages. Still, there can be

¹ Data Requests and Responses, Page 200.

² NSP's MN Compliance Filing dated October 2, 2014, Docket No. E002/M-14-789, Pgs. 9-11.

³ NSP's MN Reply Comments dated November 3, 2014, Docket No. E002/M-14-789, Page 6.

⁴ Data Requests and Responses, Page 200.

1 instances where adding generation beyond an adequate reserve margin is
2 reasonable and efficient. Making such a determination is part of the
3 Integrated Resource Plan (IRP). Generally, it is more advantageous to
4 manage generation resources as closely as possible to load requirements
5 because it is expensive to carry more generation than required or needed.
6

7 **Q: How has resource adequacy changed in recent years?**

8 A: The structure of generation resource adequacy has changed under regional
9 grid operators like the one NSP belongs to; Midcontinent Independent System
10 Operator (MISO). One of the primary values of operating the electric system
11 on a regional basis is to share generation assets to enable companies to
12 carry a smaller reserve margin and improve reliability at the same time. It is
13 no longer necessary or desirable for every utility to carry large amounts of
14 excess generation as though they are still operated on a stand-alone basis.
15

16 MISO requires a system wide planning reserve margin (PRM) of 7.1%.⁵ Said
17 another way, NSP is required to carry excess generation of 7.1% above its
18 peak demand coincident with the MISO system less its load management
19 capabilities.⁶ Historically, MISO's required PRM has continued to decline.⁷
20 MISO expects its future PRM to continue shrinking.⁸ As a result, capacity
21 needs will likely diminish relative to overall needs.
22

23 **Q: Does the PRM account for outages and undeliverable power?**

24 A: Yes. The installed or nameplate capacity (ICAP) ratings of generators on
25 MISO's system are adjusted downward to reflect only generation that is
26 available and deliverable; also known as unforced capacity (UCAP) rating.
27 The UCAP ratings account for the robustness of generator interconnections

⁵ MISO 2015-2016 Loss of Load Expectation Study Report, Page 4.

⁶ Data Requests and Responses, Page 200.

⁷ MISO 2015-2016 Loss of Load Expectation Study Report, Page 32.

⁸ Ibid, Page 33.

1 and transmission availability, availability or non-availability of intermittent
2 resources, thermal derates, planned maintenance, units that are inoperable,
3 poor historical performance and estimated forced outages.⁹ As a result, the
4 7.1% planning reserve margin is a true margin above and beyond expected
5 load requirements.
6

7 **Q: How is the planning reserve margin calculated?**

8 A: MISO uses a mathematical analysis to determine what level of PRM is
9 necessary to achieve the probability of less than one-day loss of load event
10 every 10 years (or .1 day per year) in accordance with its Federal Energy
11 Regulatory Commission Tariff.¹⁰ Accordingly, the minimum PRM requirement
12 is determined by either adding Coincident Peak Demand or removing
13 Planning Resources until a 0.1 day per year solution is reached.¹¹
14

15 **Q: Does the diversity of MISO minimize the need for capacity?**

16 A: Yes. MISO coordinates transmission and generation services across 15
17 different states. Accordingly, the locational diversity within the large region in
18 terms of weather, temperatures, sunlight, peak-hour usage etc. is significant
19 and permits the use of lower system wide reserve margins than otherwise
20 would be required for a stand-alone company. For example, it may be cool
21 and raining in Bismarck yet hot and humid in Minneapolis allowing for more
22 efficient utilization of generation resources across the electric grid.
23

24 **Q: Provide context for the size of MISO.**

25 A: NSP is one of the larger load serving entities in MISO with less than 10,000
26 MW of peak capacity needs.¹² MISO manages over 200,000 MW of

⁹ MISO Business Practice Manual No. 011, Resource Adequacy, Appendix H, Pages 136-137.

¹⁰ MISO 2015-2016 Loss of Load Expectation Study Report, Page 4.

¹¹ MISO Business Practice Manual No. 011, Resource Adequacy, Page 25.

¹² Data Requests and Responses, Page 200.

1 generation capacity allowing for vast amounts of shared resources.¹³ The
2 administrative cost of MISO exceeds \$.25 billion a year.¹⁴ Ignoring the
3 sharing aspect and economy of scale offered through MISO's operation,
4 when additional generation is not needed, erodes the value of membership in
5 MISO.

6
7 **Q: Is there a cost to carry excess generation?**

8 **A:** Yes. The recovery of generator costs in the MISO market comes primarily
9 from running the generators. Excess generation drives down the overall price
10 of the energy market and diminishes the run time of existing generators. As a
11 result, ratepayers will pay for the full carrying costs of generators only to get a
12 smaller price for less generation in return.

13
14 Similarly, excess generation diminishes the value of capacity. Because the
15 MISO system has been in an excess capacity position, the market value for
16 excess capacity has been minimal. For instance, the clearing price for
17 capacity sold at the annual auction in 2013 was \$1.05 per MW – Day.¹⁵ In
18 2014, capacity at the annual auction garnered \$3.29 per MW – Day for
19 MISO's Zone 1 (NSP's zone).¹⁶ Therefore, the auction price in 2014 for 1
20 MW of capacity for one year would be about \$1,200 (\$3.29 times 365 days).
21 By contrast, MISO estimates the cost of new entry to be \$89,500 for 1 MW of
22 capacity for one year. As you can see, there can be a significant cost to
23 ratepayers associated with excess generation; both in terms of energy and
24 capacity prices.¹⁷

25

¹³ MISO Website, Corporate Information, Reliability Coordination Area (includes Manitoba).

¹⁴ MISO Website, 2015-2017 Budget.

¹⁵ 2013/2014 MISO Planning Resource Auction Results.

¹⁶ 2014/2015 MISO Planning Resource Auction Results.

¹⁷ MISO Business Practice Manual No. 011, Resource Adequacy, Page 106.

1 **Q: Who benefits if NSP adds excess generation?**

2 A: The MISO pool of energy is one large integrated system. Therefore, adding
3 extra generation provides another option for energizing the regional grid and
4 therefore strengthens the overall grid. As a result, pouring more resources
5 into the pool than required by MISO enriches all the members of the grid at a
6 disproportional cost to local ratepayers. The goal of NSP should be to
7 manage its generation resources to the nearest possible level required by
8 MISO.

9

10 **Q: When should excess generation resources be deployed?**

11 A: It is sometimes possible for new generation to displace existing generation
12 and still save consumers money. For instance, if the average avoided cost of
13 legacy plants' fueled by fossil fuel is 5 cents per kWh and wind energy can be
14 procured at 3 cents per kWh, it may make sense to carry the extra wind
15 generation even if it is not needed to serve existing load. In this case, the SP
16 is projected to add cost to the total system revenue requirements rather than
17 lessen the overall cost.

18

19 **Q: Can NSP incur a penalty for failing to plan for enough generation?**

20 A: Yes, but it should not occur. NSP must provide MISO with its projected
21 annual peak demand and monthly peaks and energy requirements by
22 November 1 for the following planning year.¹⁸ After the forecasts are
23 reviewed and affirmed by MISO, NSP must submit a plan to meet its native
24 load requirements. In the event available resources are not adequate to meet
25 PRM requirements, MISO conducts an annual auction to allow entities short
26 on capacity to buy capacity from those long on capacity. If NSP fails to
27 procure adequate resources or buy capacity at auction, it can choose to
28 subject itself to a MISO Capacity Deficiency Charge.¹⁹

¹⁸ MISO Business Practice Manual No. 011, Resource Adequacy, Page 18.

¹⁹ Ibid, Page 14.

1 Doing so would result in a charge of 2.748 times the Cost of New Entry
2 (CONE).²⁰ CONE is the estimated annual capital, operating, and other costs
3 that would be incurred to develop a new capacity resource.²¹ The CONE
4 value for NSP's Zone 1 is \$89,500 per MW – Year.²² The failure to plan for
5 projected load requirements and/or buy capacity when needed could result in
6 a penalty of \$245,946 per MW – Year (2.748 times \$89,500); but this should
7 not occur.

8
9 **Q: Does MISO assess penalties for forced outages?**

10 **A:** No. In the event of an unforeseen outage (such as the recent fire at Coyote
11 Station near Beulah, ND), the MISO reserve margin is designed to cover any
12 shortfalls that may occur and there are no penalties assessed by MISO.
13 Further, it is not necessary for NSP to contract for capacity that was lost due
14 to a forced outage; negating any need to over-build or over-purchase
15 generation for forced outages. This is part of the value proposition of
16 belonging to MISO and its large economies of scale.

17
18 **Q: If there is no financial or operational need for the Solar Portfolio, how
19 does NSP justify its proposal?**

20 **A:** In its application and testimony, NSP puts forward several qualitative reasons
21 for adding the SP. The following encapsulates the primary arguments
22 advanced by NSP for adding the proposed SP:

- 23
24 1. Cost effectively meets MN's Solar Energy Standard (SES)²³
25 2. Takes advantage of the Federal 30% Investment Tax Credit²⁴
26 3. Provides a hedge against future environmental regulation²⁵

²⁰ MISO Business Practice Manual No. 011, Resource Adequacy, Page 103.

²¹ FERC Order on Annual Cost of New Entry, Docket No. ER10-2090-000, Page 1.

²² MISO Business Practice Manual No. 011, Resource Adequacy, Page 106.

²³ NSP's Application, Page 1.

²⁴ Ibid, Page 9.

²⁵ Ibid, Page 11.

1 The problem with allocating some of the costs and associated renewable
2 energy credits (REC's) to ND is that it frustrates NSP's ability to achieve its
3 MN SES. MN is the only state served by NSP that requires a solar energy
4 standard. For this reason, it is in the best interest of MN to pay for its own
5 specialized generation and reap all the benefits it perceives from investing in
6 solar energy. Similarly, it is in the best interest of ND to adhere to its least
7 cost planning objectives; a win-win scenario for both states. Both states'
8 energy policies are met in the most efficient manner possible.

9
10 **Q: How does denying an ADP benefit NSP and MN?**

11 A: Let's assume that MN's SES requires NSP to acquire 75 MW of solar
12 generation. NSP would have to secure 100 MW of solar generation because
13 of the regulatory jurisdictional allocation of generation assets and purchased
14 power agreements among the various states. Because NSP is allocated
15 approximately 75% of these costs, it is necessary to add 100 MW of solar to
16 receive an allocated share of 75 MW for MN.

17
18 Instead, NSP should direct assign these projects to MN. In this way, the SES
19 is achieved more directly and prudently. Doing so avoids unnecessary rancor
20 between other states when adding these projects that are not cost effective.

21 It reduces the regulatory burden of seeking cost recovery in multiple
22 jurisdictions. It enhances NSP's chances of full cost recovery. It is a
23 friendlier and better way of considering needs of other stakeholders outside
24 MN.

25
26 **Q: How does the MN RPS compare to other states?**

27 A: MN's Renewable Portfolio Standard (RPS) for Xcel Energy is 31.5% by 2020,
28 including an SES of 1.5%. By comparison, the other states served by NSP

1 have renewable standards and objectives of 10%; except for Wisconsin with a
2 standard of 12.89%.²⁹

3

4 In conclusion, the NDPSC should consider NSP's need to meet its MN
5 mandates for SES and deny this ADP and any associated cost recovery to
6 help NSP comply with its MN obligations.

7

8

2.

9 **Q: Should NSP invest now to take advantage of the 30% ITC?**

10 A: No. Like sole source mandates for generation, subsidies from the federal
11 government distort the true economics of resource allocation. However, while
12 it pains me to say this from a pragmatic, taxpayer and free market ideology, it
13 would be foolish for NSP to ignore the "free money" offered by the Federal
14 Government to deploy solar generation. However, even with the 30% ITC,
15 NSP's reference case indicates that adding the proposed solar portfolio
16 results in additional costs of \$14 million.³⁰

17

18 **Q: Is the SP price comparable to the market price of energy?**

19 A: No, the cost of SP energy is never less than NSP's projected average cost of
20 available market energy for on-peak prices. The comparison of the SP
21 energy to off-peak prices is worse. This is true for the entire contract period.³¹

22

23 **Q: How does the SP compare to current wind energy prices?**

24 A: The SP contract prices are more than double the available wind prices for
25 similar contract periods as evidenced by Montana-Dakota Utilities Company's
26 recent ADP filing for its Thunder Spirit Wind Project.³²

27

²⁹ NSP's Integrated Resource Plan, Case No. PU-15-19, Page 56.

³⁰ NSP's ADP Application, Page 10.

³¹ Data Requests and Responses, Page 196.

³² MDU's ADP filing for Thunder Spirit Wind Project, Case No. PU-14-843.

1 **Q: Will better opportunities occur for deploying solar?**

2 **A:** Yes, solar is just coming into vogue. It is in the early development stage and
3 therefore has a lot of upside potential in terms of efficiency improvements and
4 technology advancements. According to IHS Energy's 2014 Market Brief
5 entitled "Outlook for US Solar Photovoltaic Capital Costs and Prices, 2014-
6 2030, IHS expects solar Photovoltaic capital costs to fall approximately 45%
7 by 2030. Further, IHS expects efficiency gains in collecting solar power of
8 11% to 24% between 2009 and 2030.³³

9

10 There seems to be little reason to rush to market to take advantage of the ITC
11 credit differential between 30% through 2016 and 10% thereafter except to
12 satisfy the MN SES. There is no need for additional capacity. The cost of the
13 energy from the SP is extremely high in comparison to expected energy
14 market prices and available wind generation prices for the same time period.
15 Solar efficiencies in terms of capital costs and collecting the sun's rays will
16 continue to decline as the solar industry matures much like it has for wind
17 generation, flat screen televisions, cell phones and so on. For these reasons
18 there is no need to make an opportunity buy of solar generation at this time.

19

20

3.

21

**Q: Should the NDPSC consider the value of solar energy as a hedge
22 against future environmental regulation.**

22

23

A: According to ND law:

24

The NDPSC may not use, require the use of, or allow electric utilities to use
25 environmental externality values in the planning, selection, or acquisition of
26 electric resources or the setting of rates for providing electric service.

25

26

27

Environmental externality values are numerical costs or quantified values that
28 are assigned to represent either:

27

28

29

1. Environmental costs that are not internalized in the cost of production
30 or the market price of electricity from a particular electric resource; or
2. The alleged costs of complying with future environmental laws or
31 regulations that have not yet been enacted.³⁴

30

31

32

33

³³ Data Requests and Responses, Page No. 13.

³⁴ N.D.C.C. § 49-02-23.

1
2 Also, according to ND law:

3 The commission may not increase electric rates as a result of actions taken
4 by other states requiring higher cost resources to be built, purchased, or
5 otherwise acquired as a result of the application of quantified environmental
6 externality values, as defined in section 49-02-23, as part of any resource
7 selection process.³⁵
8

9 To my knowledge, NSP has not included any numerical costs of complying
10 with future environmental laws in its econometric model when developing its
11 Reference Case and various sensitivity tests. While it has been the practice
12 of the NDPSC to consider qualitative reasons for considering potential
13 environmental laws and regulations, it is at least useful to consider the spirit
14 of these laws.³⁶
15

16 The NDPSC should also take note of its comments filed with the
17 Environmental Protection Agency (EPA) arguing that the EPA's proposed
18 Carbon Pollution Emission Guidelines for Existing Sources are not authorized
19 by Federal Law and that it circumvents the NDPSC's resource planning
20 authority.³⁷ Staff believes that granting deference in this proceeding for a
21 proposed CO² rule that may or may not stand up in court runs counter to the
22 NDPSC's position.
23

24 Nevertheless, if the NDPSC wants to consider the qualitative value of solar as
25 it pertains to the environment, note again that there is a huge price discount
26 for wind PPA's compared to solar PPA's; and wind generation essentially
27 provides the same environmental attributes as solar generation. If a hedge
28 against carbon dioxide (CO²) emissions is desired, wind energy is much
29 cheaper.
30

³⁵ N.D.C.C. § 49-06-24.

³⁶ NDPSC Big Stone 2 Order, Case No. PU-06-481, Finding 88.

³⁷ NDPSC's comments to EPA filed November 25, 2014, Case No. PU-14-736.

1 5.

2 **Q: Should the NDPSC consider the smallness of the SP's rate impact?**

3 A: Should NSP's lawyers and witnesses each give me \$100? It is a small and
4 insignificant amount to each of them in comparison to their annual salaries.
5 In relative terms, \$100 would be a smaller percentage of their salaries
6 compared to the rate impact projected by NSP of approximately .02 cents per
7 kWh.³⁹

8
9 The decision to grant or deny ADP should be determined on the merits of the
10 case and our best estimates whether the impact is great or small to
11 ratepayers. This is just the first of several MN ordered generation resources
12 that have or will be filed for ADP before the NDPSC. This case will likely
13 establish a framework for going forward.

14

15 **Q: Should the NDPSC deny recovery of replacement capacity?**

16 A: Yes, the Settlement Agreement adopted by the NDPSC in NSP's last rate
17 increase application included a Negotiating Framework for developing a
18 mechanism whereby the Company will serve its ND customers with resources
19 (real or proxy) consistent with ND's energy policies.⁴⁰ The resulting
20 negotiated mechanism is to be provided to the NDPSC for approval by June
21 30, 2015.⁴¹

22

23 In principle, ND ratepayers will be required to purchase capacity or accept a
24 proxy price for capacity when the NDPSC finds MN ordered generation does
25 not agree with ND's energy policies. However, in this instance, additional
26 capacity is not needed and therefore charging ND ratepayers a proxy price for
27 what would be its share of the SP capacity is unreasonable.

28

³⁹ NSP's ADP Application, Page 14.

⁴⁰ Order Adopting Settlement, Case No. PU-12-813, Attached Settlement Agreement, Page 14.

⁴¹ Ibid, Page 16.

1 The Settlement Agreement calling for a capacity proxy price was based on an
2 assumption that capacity would be needed. Accordingly, when capacity is
3 needed and NSP adds generation to meet a MN renewable standard that is
4 not least cost oriented, ND may substitute a proxy price for the needed
5 capacity based on its own energy policy of least cost planning.

6
7 I don't believe either party to the case imagined a situation where one state
8 would be ordering the construction of generating units beyond its native load
9 requirements; beyond the requirements of MISO at a net cost to consumers.
10 There is simply no justification for assigning additional capacity costs to ND
11 for generation capacity not needed or cost effective. To do otherwise would
12 allow one state to enrich itself based on its own perceived value of solar
13 generation and its desire for excess generation, at the expense of other
14 states.

15
16 A full denial is advantageous to NSP as it seeks cost recovery for the SP in
17 MN. The clearer the Order, the better equipped NSP will be for arguing for
18 full recovery from its Minnesota ratepayers as it seeks to meet the Minnesota
19 SES.

20
21 Finally, issuing an order denying a capacity proxy price in this instance
22 removes one of the obstacles that remains in the restack and cost allocation
23 filings to be made later in 2015 as required in the Settlement Agreement.

24
25 **Q: Does this conclude your testimony?**

26 **A:** Yes, it does.

27
28
29
30

1 **Appendix – Acronyms Used in Testimony**

ADP	Advance Determination of Prudence
CAP	Competitive Resource Acquisition Process
CO ²	Carbon Dioxide
CONE	Cost of New Entry
EPA	Environmental Protection Agency
ICAP	Installed Capacity Rating (MW)
IRP	Integrated Resource Plan
MDU	Montana-Dakota Utilities Co.
MISO	Midcontinent Independent System Operator
MPUC	Minnesota Public Utilities Commission
NDCC	North Dakota Century Code
NDPSC	North Dakota Public Service Commission
NSP	Northern States Power Company
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SES	Solar Energy Standard
SP	Solar Portfolio
UCAP	Unforced Capacity Rating (MW)

2