February 20, 2015

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
600 E Blvd Ave
Bismarck, ND 58505

Re: Case No. PU-14-810

Northern States Power Company
Solar Portfolio ADP

Dear Mr. Nitschke:

Enclosed for filing is an original copy of Advocacy Staff's direct testimony recommending that Northern States Power Company's request for an Advance Determination of Prudence for various solar farms in Minnesota be denied. Further, staff argues that cost recovery of a proxy price for capacity be denied.

Sincerely,

Mike Diller

Mike Diller
Director of Economic Regulation

Enclosure

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

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

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

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

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

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

Q: Please summarize your testimony.

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

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

A: Staff compared NSP's most recent load forecasts to the capacity of its existing generation resources noting that NSP is able to meet its load obligations without any additional generation facilities until 2024.[1]

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

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

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

- 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]

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

A: NSP already carries excess generation via its planning reserve margin to 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.

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

Q: How has resource adequacy changed in recent years?

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

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

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

A: Yes. The installed or nameplate capacity (ICAP) ratings of generators on MISO's system are adjusted downward to reflect only generation that is available and deliverable; also known as unforced capacity (UCAP) rating. 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.

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

Q: How is the planning reserve margin calculated?

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

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

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

Q: Provide context for the size of MISO.

A: NSP is one of the larger load serving entities in MISO with less than 10,000 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.

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

Q: Is there a cost to carry excess generation?

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

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

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[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.

Q: Who benefits if NSP adds excess generation?

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

Q: When should excess generation resources be deployed?

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

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

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

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[18] MISO Business Practice Manual No. 011, Resource Adequacy, Page 18.
[19] Ibid, Page 14.

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

Q: Does MISO assess penalties for forced outages?

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

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

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

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

[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.

4. Provides a hedge against natural gas prices[26]
5. The impact to customers' bills are really small[27]

1.

Q: Should the NDPSC consider the MN Solar Energy Standard?

A: Yes. Minnesota (MN) borders our state. We trade with each other. We share MISO's Zone 1 to ensure resource adequacy in our region. NSP provides service in both states. We should seek to mutually and beneficially coexist whenever possible so long as doing so is not detrimental to our own citizenry. In this instance, I think the SP projects provide a unique opportunity where both MN and ND can benefit.

Before I get to that, please note that the voters of MN have chosen their representatives who in turn have determined that having solar energy is important to MN by mandating that 1.5% of its energy needs come from solar by 2020 and a goal of 10% by 2030.[28] Mandates, by nature, lead to ineffective allocation of resources but clearly MN has determined that the benefits of solar and the additional diversity of resources are worth the extra cost. There is nothing inherently wrong with different state policies, especially when both energy policies can be accommodated.

From a technical and fairness standpoint, basic cost allocation and rate design principles require that costs be assigned to the cost causers whether allocating costs between states or to various customer classes. Attempting to allocate MN costs to ND ratepayers to meet a MN mandate is comparable to taxation without representation and works against basic cost allocation principles and rate design techniques familiar to the NDPSC.

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[26] Ibid, Page 13.
[27] Ibid, Page 14.
[28] NSP's Application, Page 2.

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

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

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

Instead, NSP should direct assign these projects to MN. In this way, the SES is achieved more directly and prudently. Doing so avoids unnecessary rancor between other states when adding these projects that are not cost effective. It reduces the regulatory burden of seeking cost recovery in multiple jurisdictions. It enhances NSP's chances of full cost recovery. It is a friendlier and better way of considering needs of other stakeholders outside MN.

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

A: MN's Renewable Portfolio Standard (RPS) for Xcel Energy is 31.5% by 2020, including an SES of 1.5%. By comparison, the other states served by NSP have renewable standards and objectives of 10%; except for Wisconsin with a standard of 12.89%.[29]

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

2.

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

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

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

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

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

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

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[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.

Q: Will better opportunities occur for deploying solar?

A: Yes, solar is just coming into vogue. It is in the early development stage and therefore has a lot of upside potential in terms of efficiency improvements and technology advancements. According to IHS Energy's 2014 Market Brief entitled "Outlook for US Solar Photovoltaic Capital Costs and Prices, 2014-2030, IHS expects solar Photovoltaic capital costs to fall approximately 45% by 2030. Further, IHS expects efficiency gains in collecting solar power of 11% to 24% between 2009 and 2030.[33]

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

3.

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

A: According to ND law:

> The NDPSC may not use, require the use of, or allow electric utilities to use environmental externality values in the planning, selection, or acquisition of electric resources or the setting of rates for providing electric service. Environmental externality values are numerical costs or quantified values that are assigned to represent either:
> 1. Environmental costs that are not internalized in the cost of production or the market price of electricity from a particular electric resource; or
> 2. The alleged costs of complying with future environmental laws or regulations that have not yet been enacted.[34]

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[33] Data Requests and Responses, Page No. 13.
[34] N.D.C.C. § 49-02-23.

Also, according to ND law:

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

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

The NDPSC should also take note of its comments filed with the Environmental Protection Agency (EPA) arguing that the EPA's proposed Carbon Pollution Emission Guidelines for Existing Sources are not authorized by Federal Law and that it circumvents the NDPSC's resource planning authority.[37] Staff believes that granting deference in this proceeding for a proposed CO^2 rule that may or may not stand up in court runs counter to the NDPSC's position.

Nevertheless, if the NDPSC wants to consider the qualitative value of solar as it pertains to the environment, note again that there is a huge price discount for wind PPA's compared to solar PPA's; and wind generation essentially provides the same environmental attributes as solar generation. If a hedge against carbon dioxide (CO^2) emissions is desired, wind energy is much cheaper.

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[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.

Lastly, environmental hedges are like any other hedge which carries both risks and rewards. Too often, the benefits of limiting exposure to higher cost outcomes are trumpeted without equally considering the downside of a hedge.

What if the White House falls into the hands of Republicans in 2016 and EPA extremism is reigned in? What if the courts find that the EPA has run amuck and does not have the authority to foist CO^2 rules upon the states? What if CO^2 concerns turn out to be the greatest hoax perpetrated on mankind but instead solar flaring from the world's largest heat source is determined to be the primary instigator of climate change? Hedging against future environmental laws or regulations that have not yet been enacted can result in incurring large costs to comply with something that may or may not happen. There are both risks and rewards associated with hedges. Early compliance may or may not be beneficial. Early compliance to rules that may someday be enforceable may not be counted towards compliance of an eventual rule or law.

4.

Q: Does the SP provide a hedge against natural gas prices?

A: Yes, but as stated earlier, wind generation is much cheaper and provides a hedge against natural gas prices. Similarly, as stated with the idea of an environmental hedge, a natural gas hedge includes risks as well as benefits. In its application, NSP shows in its "low gas cost" scenario that the additional cost of adding the SP increases the overall revenue requirements by $41 million, instead of $14 million in its Reference Case.[38] There are both risks and rewards associated with hedges and both should be recognized by the NDPSC in making its determination in this proceeding.

[38] NSP's ADP Application, Page 10.

5.

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

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

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

Q: Should the NDPSC deny recovery of replacement capacity?

A: Yes, the Settlement Agreement adopted by the NDPSC in NSP's last rate increase application included a Negotiating Framework for developing a mechanism whereby the Company will serve its ND customers with resources (real or proxy) consistent with ND's energy policies.[40] The resulting negotiated mechanism is to be provided to the NDPSC for approval by June 30, 2015.[41]

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

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[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.

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

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

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

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

Q: Does this conclude your testimony?

A: Yes, it does.

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)