

December 1, 2015

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

Re: **Case No. PU-12-813**
Case No. PU-13-194
Case No. PU-13-195
Case No. PU-13-706
Case No. PU-13-707
Case No. PU-13-708
Case No. PU-13-742
Case No. PU-13-743
Case No. PU-15-096

Northern States Power Company
Staff Testimony Supporting Negotiated Agreement

Dear Mr. Nitschke:

Enclosed for filing is an original copy of Advocacy Staff's direct testimony supporting the Negotiated Agreement in the above captioned proceedings filed on September 30, 2015.

I look forward to testifying at the Hearing scheduled for December 15, 2015.

Sincerely,



Mike Diller
Director of Economic Regulation

Enclosure

C: Dave Sederquist, Zeviel Simpser, Alison Archer

111	PU-13-708	Filed 12/01/2015	Pages: 11	Pre-filed direct testimony of Mike Diller
112	PU-13-707	Filed 12/01/2015	Pages: 11	Pre-filed direct testimony of Mike Diller
112	PU-13-706	Filed 12/01/2015	Pages: 11	Pre-filed direct testimony of Mike Diller
130	PU-13-195	Filed 12/01/2015	Pages: 11	Pre-filed direct testimony of Mike Diller
123	PU-13-743	Filed 12/01/2015	Pages: 11	Pre-filed direct testimony of Mike Diller
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90	PU-15-96	Filed 12/01/2015	Pages: 11	Pre-filed direct testimony of Mike Diller

**BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

***In the Matter of Northern States Power Company's
Application for Approval of a Negotiated Agreement
Relating to North Dakota's Generation Resource Policy***

Case No. PU-12-813

Case No. PU-13-194

Case No. PU-13-195

Case No. PU-13-706

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Case No. PU-13-742

Case No. PU-13-743

Case No. PU-15-096

DIRECT TESTIMONY

OF

MIKE DILLER

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

December 1, 2015

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 (commission). I am a utility analyst
4 and provide direction to a small staff. I have more than 30 years of utility
5 regulatory experience including service to the Oklahoma Corporation
6 Commission.

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 commission on numerous occasions
11 including acquisition and merger proposals, rate cases, settlements, advance
12 determination of prudence requests and rule changes.

13 The commission appointed me to advocacy staff (staff) in NSP's last rate
14 increase application (PU-12-813) and other consolidated cases that resulted
15 in a multi-year rate plan settlement approved by the commission. The
16 Comprehensive Settlement Agreement adopted by the commission on
17 February 26, 2014 also required, among other things, continued good faith
18 negotiations to develop long-term solutions to energy policy differences that
19 exist between Minnesota and North Dakota. I have been the principal
20 negotiator for staff and have testified previously in these proceedings.

21 Q: **Provide a summary of the 2014 Comprehensive Settlement Agreement
22 (CSA) as it pertains to generation resources.**

23 A: The CSA was negotiated to implement a framework to reflect North Dakota's
24 energy policy priorities as expressed by the commission. The commission
25 has been resolute in its support for least cost planning and so any framework
26 for handling future additions to the generation resource mix must incorporate
27 that concept. A hard deadline of June 30, 2015 was established for the
28 development of the Resource Treatment Framework (RTF) with a significant
29 penalty for failure to establish such a plan. The RTF was to address the long-

1 term interest of the commission in exerting more control over the energy
2 resource mix serving North Dakota.

3 The CSA developed a framework for developing the RTF so that existing
4 resources deemed inconsistent with North Dakota energy policies would be
5 repriced based on “like” replacements using real or proxy pricing and that any
6 future resources would be priced to reflect marginal pricing for a similar type
7 of resource. In the end, the goal was to have a generation resource mix that
8 would be a reasonable approximation of what would have occurred had NSP
9 historically developed its overall resource mix consistent with North Dakota
10 policy.

11 The CSA also required that staff consider the financial impact to NSP of the
12 RTF including reasonable and mutually agreeable implementation schedules
13 and deadlines.

14 The CSA acknowledged that having generation located closer to NSP’s load
15 centers in North Dakota provides benefits to both North Dakota customers as
16 well as NSP’s other customers served by the Company.

17 The CSA included a commitment by NSP to build “up to 400 MW” of thermal
18 generation in North Dakota no later than 2036, consistent with the principles
19 of orderly development and least-cost planning so that any new generation
20 would be both cost effective and needed.

21 Q: **What is the purpose of your testimony in this proceeding?**

22 A: To support the September 30, 2015 Negotiated Agreement between NSP and
23 staff.

24

25 Q: **Provide a brief summary of this new Negotiated Agreement.**

26 A: The Negotiated Agreement provides 6 major agreements:

- 1 1. Provides additional time to develop a long-term RTF for handling
- 2 energy resource policy differences that will continue to occur between
- 3 Minnesota and North Dakota.
- 4 2. Changes the overall thermal generation commitment in North Dakota
- 5 from "up to 400 MW" to "at least 200 MW" and moves the completion
- 6 time frame from 2036 to no later than December 31, 2025, including a
- 7 sizable penalty for non-compliance.
- 8 3. Provides a rate freeze for one additional year through the end of 2017.
- 9 4. Allows cost recovery for the biomass purchase power agreements and
- 10 the Pleasant Valley and Odell wind projects.
- 11 5. Removes from cost recovery all existing high cost Community Based
- 12 Energy Development (CBED) and small solar projects on January 1,
- 13 2016 or the date the Negotiated Agreement is adopted by the
- 14 commission, whichever is later.
- 15 6. Supports the use of the 12 coincident peak (12 CP) jurisdictional
- 16 allocation method for purposes of assigning generation and
- 17 transmission costs through December 31, 2025.

18

19 **Q: Why do you need more time to develop the RTF for allocating future**
20 **generation resources to North Dakota?**

21 **A:** The additional time is more for NSP than for staff. NSP sees the task of
22 allocating resources in a non-traditional way to ND as daunting and nearly
23 impossible to achieve. NSP's inability to develop a solution to date likely has
24 more to do with its inability to accept a less integrated approach going
25 forward. It takes time for a large utility to change direction but I recommend
26 that the commission stand firm and require a less integrated approach going
27 forward nonetheless. The state of Minnesota is not going back to least-cost
28 planning for its generation resource additions anytime soon and North Dakota
29 should not acquiesce to building generation that is neither needed nor least-
30 cost oriented. That said, the Negotiated Agreement gives NSP more time to

1 plan for what in essence is already happening through the disallowance of
2 existing CBED and the small solar units per the Negotiated Agreement; the
3 already disallowed 100 MW Aurora Solar and 187 MW Solar Energy Portfolio
4 projects; and hopefully the Calpine Energy Center purchase power
5 agreement not yet decided by the commission. North Dakota's generation
6 portfolio is indeed diverging from NSP's traditional allocation of integrated
7 system costs.

8

9 I think part of the transitional difficulties to a North Dakota specific energy plan
10 is that the relatively simple approach of allocating a greater share of
11 agreeable plants (energy and capacity) to ND and none of the objectionable
12 resources likely increases the cost to Minnesota and lowers the cost to North
13 Dakota.

14

15 **Q: Why would it be fair to allocate more of the legacy plants that are largely**
16 **depreciated and cheaper to North Dakota while allocating all of the**
17 **Minnesota green initiative resources to Minnesota?**

18 **A:** If Minnesota desires green electrons for its ratepayers without any apparent
19 regard for cost, then Minnesota ratepayers should pay for it. Whatever
20 capacity is assigned to the objectionable units and whatever energy is
21 generated from these units should come off the top of Minnesota's capacity
22 and energy requirements before allocating the rest of the system capacity and
23 energy costs to its other jurisdictions. Doing so assures MN of receiving the
24 green electrons and capturing the Renewable Energy Credits for its
25 ratepayers. It avoids assigning objectionable costs to North Dakota. It avoids
26 creating the potential for stranded costs or the potential for recovering more
27 or less than 100% of the costs through proxy pricing. Of course this straight-
28 up simple approach doesn't work if Minnesota will not pay for the cost of its
29 own green initiatives; but that is not a burden placed on NSP by North Dakota
30 and we should not feel the urge to bear it.

1

2 **Q: Why did staff agree to the term of adding “at least 200 MW’s” of thermal**
3 **generation to the Eastern side of North Dakota?**

4 A: After giving consideration to the size of NSP’s load requirements in North
5 Dakota, staff reasoned that NSP’s future ownership of 350 MW’s of wind
6 generation plus at least 200 MW’s of thermal generation in North Dakota was
7 a reasonable start towards providing local generation. For perspective, North
8 Dakota makes up about 5% of NSP’s regional capacity requirements and 200
9 MW’s of thermal generation represents about 2% of NSP’s system wide
10 capacity needs. When combining the wind and thermal generation, these
11 local generation facilities will provide the capability of producing the energy
12 needed for NSP’s North Dakota operations. Overall, the Negotiated
13 Agreement will continue to promote local grid stability and reliability and
14 provide a platform for future generation development in North Dakota.

15

16 **Q: What is the value of one additional year of rate moratorium?**

17 A: It is difficult to estimate given the multitude of variables to consider between
18 now and 2018. I think a \$10 million value is not unrealistic given NSP’s
19 recent multi-year rate increases. If nothing else, it gives ratepayers
20 assurance, outside of some unforeseen or extraordinary event, that NSP’s
21 base rates will remain stable through 2017.

22

23 **Q: Why did you agree to cost recovery for the biomass generation facilities**
24 **and two large wind farms located in MN?**

25 A: The CSA adopted by the commission in 2014 excluded these costs from rate
26 recovery beginning January 1, 2016 absent an RTF agreement between NSP
27 and staff for dealing with cost recovery of future generation resources. The
28 recent Negotiated Agreement removes that obligation of mutual agreement
29 between NSP and staff and places that burden of framework development
30 more squarely on NSP. Still, staff will remain an active partner and provide

1 guidance until the framework is established and approved. More than that,
2 we will adamantly oppose any framework developed by NSP that is not fair
3 and reasonable to its North Dakota ratepayers.

4

5 As NSP points out in its testimony, the biomass facilities have come about
6 through negotiations with its Minnesota stakeholders in order to ensure
7 continued operation of its low cost nuclear generation facilities. I think it
8 would have been interesting to see the outcome had NSP decided to not be
9 taken hostage by the environmental community and simply moved forward to
10 close its low cost carbon free nuclear plants. Nevertheless, North Dakota
11 ratepayers have been paying for biomass electricity for many years and have
12 enjoyed its share of NSP's low cost nuclear power.

13

14 Staff's decision to allow biomass cost recovery was a hard decision but a
15 choice that we had to make. The nuclear plants are located in MN and so MN
16 requirements to keep them open and operating are unavoidable. It is this
17 kind of history that the commission should consider before granting ADP to
18 generation facilities located in other states. The commission has little control
19 and influence over generation facilities located in another state.

20

21 Given the history behind the biomass facilities and the lack of NSP's success
22 in convincing Minnesota regulators to pay for North Dakota's portion of the
23 biomass facilities, staff does not believe NSP has a reasonable opportunity to
24 recover these costs other than through North Dakota rate recovery. Staff
25 agreed in the CSA to consider the financial impact to the Company in its
26 future negotiations with NSP and therefore agreed to cost recovery for North
27 Dakota's share of the biomass generation facilities.

28

29 The inclusion of the Pleasant Valley and Odell wind farms are a benefit to
30 North Dakota ratepayers in terms of energy cost and environmental offsets for

1 dealing with the Clean Power Plan. They were originally excluded from cost
2 recovery, barring a framework agreement, in order to help NSP meet its
3 renewable mandates in Minnesota and to offset some of the cost
4 disallowances for the biomass facilities. Therefore, the inclusion of the
5 biomass facilities for cost recovery in North Dakota as part of the Negotiated
6 Agreement requires adding back the low-cost wind farms.

7

8 **Q: If the non-recoverable biomass facilities in Minnesota argue for cost**
9 **recovery in North Dakota, why did staff push for non-recovery of costs**
10 **associated with NSP's CBED projects?**

11 A: CBED projects are Minnesota programs for Minnesotans and were not
12 required for the continued operation of economic and functional baseload
13 generation facilities.

14

15 **Q: Why did staff agree to use 12 CP through December 31, 2025 for**
16 **allocating generation and transmission resources?**

17 A: Staff worked with the company and independent consultant to evaluate the
18 various methods used for allocating jurisdictional resources. The result of
19 that effort was filed by NSP on April 27, 2015, Docket #228, Case No. PU-12-
20 813. Of the 12 jurisdictional allocation methods evaluated, staff was partial to
21 the Equivalent Peaker method using a single peak demand rather than the 12
22 CP Method currently used by all of NSP's regulatory jurisdictions.

23

24 As it turns out, staff's preference was quite comparable to the 12 CP in terms
25 of stability and predictability. In terms of allocated cost to North Dakota, the
26 Equivalent Peaker method allocated less cost to North Dakota in the earlier
27 study years (2004-2013) but more cost to North Dakota two out of the last
28 three years covered in the evaluation period. During the 10 year study
29 period, the 12 CP allocated cost to North Dakota ranged from 5.63% to 6.11%
30 whereas the Equivalent Peaker method ranged from 5.38% to 6.02%.

1 Because of the wide use of 12 CP among all of NSP's jurisdictions, changing
2 the method of allocation for North Dakota should only be done when there is
3 significant reason to do so. Given the results of the study, staff agreed to
4 provide NSP with some long-term assurance that it would not advocate
5 changing the method until after 2025 at the earliest. The 12 CP Method has
6 been used for many years and a 10 year commitment to provide regulatory
7 certainty is reasonable given the results of the study.
8

9 **Q: Please summarize why you support the Negotiated Agreement?**

10 **A:** The Negotiated Agreement is fair and reasonable for both NSP and its North
11 Dakota customers. Following are the primary reasons for supporting the
12 Negotiated Agreement.

- 13 • Provides additional time for NSP to develop an RTF responsive to
14 North Dakota's energy policies.
- 15 • Continues North Dakota's practice of least cost planning.
- 16 • Secures one additional year of rate moratorium through 2017.
- 17 • Provides clarity and certainty as to how generation and transmission
18 assets are to be allocated among NSP's various jurisdictions.
- 19 • Adds additional low cost wind resources useful in the implementation
20 of the Clean Power Plan.
- 21 • Brings thermal generation to the Eastern part of North Dakota within
22 the next 10 years.
- 23 • Adds security and stability to the local grid serving North Dakota's
24 largest population segment.
- 25 • Allows ample time for planning the new thermal generation to coincide
26 with NSP's need for additional capacity.
- 27 • Provides a greater impetus for natural gas development in the Eastern
28 part of North Dakota.
- 29 • Provides a stronger opportunity for additional energy development in
30 the future.

1

2 **Q: What happens if the commission rejects the Negotiated Agreement?**

3 A: If the commission were to reject the Negotiated Agreement without providing
4 additional guidance, NSP could argue that it met its obligation to file a
5 Negotiated Agreement. Therefore, the remedial action to disallow certain
6 renewable energy costs on January 1, 2016 required in the original
7 Comprehensive Settlement Agreement would no longer be required. This
8 would result in North Dakota ratepayers continuing to pay for the Minnesota
9 CBED and small solar projects.

10

11 **Q: Do you have any recommendations for the commission if it chooses to**
12 **reject the Negotiated Agreement?**

13 A: Staff recommends that the commission provide some guidance for terms it
14 finds objectionable so as to assist in further negotiations. Alternatively, I
15 recommend that the commission order that the original remedial action be
16 implemented for failure to develop an RTF for developing a resource mix
17 consistent with North Dakota energy policies.

18

19 **Q: Does this conclude your testimony?**

20 A: Yes, it does.