

TESTIMONY

JAMES A HEIDELL

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY

CASE NO. PU-18-430

ADVANCE DETERMINATION OF PRUDENCE – DAKOTA RANGE III WIND FACILITY

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1 **I. Introduction**

2 **Q. Would you please state your name, affiliation, and address?**

3 **A.** My name is James A. Heidell. I am a Director at PA Consulting Group, Inc. (PA). My
4 business address is 1700 Lincoln Street, Suite 3550, Denver, CO 80203.

5
6 **Q. On whose behalf are you filing this testimony?**

7 **A.** I am filing this testimony on behalf of the Advocacy Staff of the North Dakota Public
8 Service Commission (Commission or NDPSC).

9
10 **Q. Please summarize your qualifications and experience.**

11 **A.** I have worked in the energy industry for the past 35 years, primarily specializing in
12 electricity and utilities. I have worked on issues related to resource planning, rates,
13 analysis of electricity markets, and analysis of the economics of financial transactions for
14 utilities and wholesale generation owners. My academic background includes a BSE in
15 civil engineering from Tufts University, a MS in engineering economics from Stanford
16 University, and an MBA in finance from the University of Washington. I am a Chartered
17 Financial Analyst. My CV is provided in Exhibit JAH-1.

18
19 **Q. Have you testified before the North Dakota Public Service Commission previously?**

20 **A.** Yes. I testified on behalf of Montana-Dakota Utilities in the matter of Montana-Dakota
21 Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone
22 II Generating Station Case Nos. PU-06-481 and PU-06-482. I have submitted pre-filed
23 direct testimony on behalf of Advocacy Staff in the following dockets:

- 24 • Northern States Power Company's request for an Advanced Determination of
25 Prudence for Dakota Range, Case Number PU-17-372
- 26 • Northern States Power Company's request for an Advanced Determination of
27 Prudence for 1,550 MW of Wind, Case Number PU-17-120;
- 28 • Otter Tail Power Company's Request for an ADP for the Astoria CT and
29 Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, and PU-17-143;

- 1 • Advance Prudence – Biomass Application for deferred accounting Northern
2 States Power Company, Case Nos. PU-17-270, PU-17-271, and PU-17-322
- 3 • Northern States Power Company Resource Treatment Framework, Case Nos. PU-
4 12-813 et al.

5
6 **Q. What is the purpose of your testimony?**

7 A. The purpose of my testimony is to provide the Commission with my assessment of the
8 Northern States Power Company's (NSP or the Company) request for an Advance
9 Determination of Prudence (ADP) for the proposed Power Purchase Agreement (PPA)
10 between the Company and the Dakota Range III Wind Project (Project).
11 The Company has applied (Application) for an ADP for the Project, indicating to the
12 Commission that the Project is priced below the Company's system average cost and will
13 therefore result in ratepayer savings. Additionally, in its Application the Company states
14 that the Project's renewable energy attributes are needed in association with a separate
15 Retail Electric Service Agreement (RESA) the Company has executed with a new electric
16 service customer in Minnesota.¹
17 My testimony provides the Commission with my evaluation of the Project's economics
18 and associated impacts on the Company's North Dakota customers and ultimately my
19 recommendation of whether or not the Commission should approve the ADP.

20
21 **Q. Would you please summarize the organization of your testimony?**

22 A. Yes. I start with presenting my recommendations and findings and then I discuss in detail
23 the analysis I conducted to support my recommendations and findings. I then address
24 additional factors considered. Finally, I address proposed conditions on approval of the
25 ADP. My testimony is separated into fifteen sections:

- 26 • A summary of my recommendations (Section II);

¹ The customer is not named in the NSP North Dakota application. However, in public documents filed with the MPUC the customer is identified as Google and is also referred to as the Becker Data Center. The actual Retail Electric Service Agreement is signed with an entity called Honeycrisp Power LLC.

- 1 • A summary of my findings (Section III);
- 2 • An overview of the Situation (Section IV);
- 3 • An overview of the PPA (Section V);
- 4 • An overview of the data center sales contract (Section VI);
- 5 • An assessment of the need for the Project (Section VIII);
- 6 • An evaluation of the Company's economic analysis of the Project (Section IX);
- 7 • Evaluation of NSP's Supplemental Strategist Runs (Section X)
- 8 • My independent economic analysis of the Project (Section XI);
- 9 • An assessment of the projected energy cost savings associated with the Project to
- 10 the Company's North Dakota customers (Section XII);
- 11 • Allocation of generation demand costs (Section XIII);
- 12 • Accounting for fuel and purchase power if the ADP is rejected (Section XIV); and
- 13 • Consideration of additional issues (Section XV).

14
15 **Q. Are you sponsoring any exhibits to your testimony?**

16 **A.** Yes, I am sponsoring three exhibits:

- 17 • Exhibit JAH-1: James Heidell CV
- 18 • Exhibit JAH-2: PA Projected Energy Cost Savings Compared to Market
- 19 • Exhibit JAH-3 PA Projected Cost Savings Including the Google Load

20
21 **II. Summary of Recommendations**

22 **Q. What is your recommendation with regard to approving the Company's**
23 **Application for an ADP to add the proposed Project to Company's integrated**
24 **system?**

25 **A.** My recommendation is that the Commission approve the ADP. It is important to
26 understand that this recommendation is based upon my conclusion that NSP's North
27 Dakota customers are unlikely to receive any significant benefits or harm from the net
28 impact of entering into the Dakota Range III PPA and adding Google's Becker Data

1 Center (Data Center) load. Based upon my analysis, there is a reasonable expectation that
2 the Dakota Range III project would lower average system cost if the impetus for signing
3 the PPA were removed. In other words, if NSP were not adding the Data Center load to
4 its system, which will effectively consume nearly all the energy production from the
5 Project. When I evaluated the cost impact of serving the additional Data Center load, as
6 well as the impact on North Dakota customers' allocation of system energy and capacity
7 costs, my conclusion is that there are unlikely to be any significant cost savings for North
8 Dakota customers.

9 My recommendation is based upon my conclusion that the addition of both the PPA and
10 the Data Center are likely to result in neither significant harm, nor significant benefit to
11 North Dakota ratepayers. My recommendation also factors in the complications that arise
12 with both the exclusion of a new resource as a system resource and the potential issues of
13 evaluating a resource addition in the context of soliciting a major single source load
14 addition. In the hypothetical situation that the additional load was the result of organic
15 load growth and the PPA procurement was not driven by the load, then the addition of the
16 low-cost wind PPA would result in savings to North Dakota customers.

17
18 **Q. If the Commission approves the PPA do you have any recommended conditions on**
19 **the approval?**

20 **A.** Yes, I have two recommendations related to the treatment of the Renewable Energy
21 Credits (RECs). Since NSP is proposing to add the Dakota Range III PPA as a system
22 resource, North Dakota customers should receive financial compensation for its share of
23 the RECs even though NSP will retire all the RECs for the benefit of the Google data
24 center. The second condition is that no cost should be allocated to North Dakota should
25 NSP have to purchase RECs to satisfy its commitments under the contract with Google.

26
27 **Q. What is your recommendation with regard to how to treat Dakota Range III if the**
28 **Commission does not approve the ADP?**

29 **A.** If the Commission does not approve the ADP, my recommendation is to reject NSP's
30 proposed treatment that would mirror the existing approach for accounting for disputed

1 PPA's in the Fuel Cost Adjustment (FCA). The current approach used for addressing high
2 cost disputed resources is not applicable in this situation where a low cost resource is
3 being added to serve a discretionary new load. In this case if the cost of the resource is
4 removed then it is also necessary to remove the cost of serving the data center load.
5

6 **III. Summary of Findings**

7
8 **Q. Would you please provide a summary of the findings in your testimony that support**
9 **your recommendation regarding the Commission's treatment of the Application**
10 **and its request for an ADP?**

11 **A.** Based upon my review and analysis of the testimony filed in the Application, the exhibits
12 contained within the Application, and the information produced in discovery, I find the
13 following:

- 14 • The proposed PPA describes the terms and conditions under which the Company
15 will purchase the output of the Project at below market pricing, which is expected
16 to lower NSP's average fuel and purchased power costs compared with the
17 Company's current system.
- 18 • After consideration of wind integration costs and potential curtailments, the PPA
19 is expected to be a lower cost resource compared with the Company making
20 wholesale purchases at Minnesota Hub prices.
- 21 • The PPA does not meet an immediate need for capacity as the first capacity
22 resource added to the system in the reference case is a combustion turbine in
23 2027.
- 24 • As opposed to the PVRR savings of \$22M in the Application, the PVRR will actually
25 increase due to adding the Data Center load.² However, there are potentially small

² Reference Case Savings, Table 2, NSP Application for Advanced Determination of Prudence Docket No. PU-18-430, p 10.

1 savings to North Dakota as a result of the allocation of a small percentage of the
2 system costs.

- 3 • The evaluation of potential savings associated with the Dakota Range III PPA should
4 consider the impact of the Data Center given that the PPA is intended to meet the
5 incremental renewable energy requirements specified in the RESA.
- 6 • There are unlikely to be any significant savings to North Dakota customers after
7 incorporating estimates of the impact of serving the Data Center load, the net impact
8 of the change in system revenue requirements, and the energy and demand costs
9 allocated to North Dakota.
- 10 • If the data center load was part of the base case load forecast, i.e. if the starting load
11 forecast was higher, then the estimated savings from adding the PPA would be similar
12 to the savings put forth in the Company's application which did not consider the data
13 center load.

14 15 **IV. The Impetus for the PPA**

16
17 **Q. Please provide an overview of the Company's Application for the ADP.**

18 A. The Company is proposing to execute a twelve-year PPA with Dakota Range III, LLP,
19 the owner of a 151.2 MW wind facility being developed in South Dakota. The project is
20 currently owned by ENGIE IR Holdings, LLC. The Project is expected to be placed into
21 service in 2020 and qualify for one hundred percent of the federal Production Tax Credit
22 (PTC). The Project is co-located with the Dakota Range I and II facilities, which are
23 owned by the Company. The Company will pay a fixed price of **[Trade Secret Begins]**
24 **[REDACTED]** **[Trade Secret Ends]** for electricity from the Project over the twelve-year
25 PPA. The Company's position put forth in the Application is that the Project is justified
26 based upon anticipated energy cost savings even though there is not a near-term need for
27 new generation.

28 The primary impetus for the PPA is the Company's Retail Electric Service Agreement
29 (RESA) with the Data Center to be located adjacent to the Sherco Power plant in Becker,
30 Minnesota. The RESA is complex and the obligations of NSP are a function of the

1 amount of load the Data Center will add to the system. However, at a high level NSP
2 must procure incremental renewable resources to serve the Data Center load. In addition,
3 the near-term expectation is that NSP will be procuring an additional 150 MW of wind to
4 serve the anticipated load of the Data Center in its first ten years of operations.³

5 In the Application, the Company also points to potential benefits to North Dakota
6 resulting from adding a large load in Minnesota that will shift the allocation of power
7 costs based upon the 12 CP method. A significant shortcoming of the Application is that
8 its identified savings analysis does not incorporate the anticipated increased load from the
9 Data Center.

10
11 **Q. Why is it a shortcoming that the Company's ADP Application's analysis does not**
12 **include the Data Center load?**

13 A. While the timing and the precise amount of new load associated with the Data Center is
14 uncertain, it has the potential to be the largest retail customer on the NSP system.⁴ The
15 economic modeling in Strategist incorporated in the Application characterizes the
16 benefits of adding the Dakota Range III PPA without considering Google's Data Center
17 load being added to the system. At a high level, the Strategist modeling of costs captures
18 the benefits from increased market sales and deferring the need for new generation
19 capacity. However, the addition of the Data Center load will result in the acceleration of
20 the need for new capacity; further, during the timeframe of the PPA the amount of
21 surplus energy sales does not increase due to the NSP system load increasing as a result
22 of the Data Center. As I explain later, at the request of Advocacy Staff, the Company
23 developed additional Strategist runs to incorporate the load from the Data Center.

24
25 **Q. Will the Dakota Range III project be used to exclusively serve the Google Data**
26 **Center Load?**

³ NSP issued an RFP on April 10 for another 150 MW with responses due on May 1. (see response to NDPSC 1-20)

⁴ PETITION CONTRACTS FOR PROVISION OF ELECTRIC SERVICE TO GOOGLE'S MINNESOTA DATA CENTER PROJECT DOCKET NO. E002/M-19, p 48.

1 A. No, NSP is proposing to treat Dakota Range III as a system resource. The energy and
2 capacity requirements imposed by the Data Center likewise will be served from system
3 resources (including any wholesale market purchases). However, over the life of the
4 initial period of the RESA, conceptually the total load of the Data Center will be met with
5 incremental new renewable resources. The actual matching of Data Center energy
6 consumption and new resource requirements on an annual basis is subject to specific
7 contract terms that are also a function of the Data Center's total load. On an hour by hour
8 basis there is neither an expectation, nor a requirement to match the incremental Data
9 Center load with the production from the incremental renewable energy resources.

10 **[Trade Secret Begins]** [REDACTED]

11 [REDACTED]
12 [REDACTED] **[Trade Secret Ends]**.

13
14 **Q. Is the NDPSC being requested to approve the Google Data Center RESA?**

15 A. No. The Google Data Center RESA is a Minnesota retail load contract under review by
16 the Minnesota Public Utilities Commission (MPUC). NSP is requesting that the MPUC
17 approve three agreements addressing the special rate and the contract terms associated
18 with serving the retail load and recovery of those costs.⁵ My understanding is that the
19 rates charged to retail customers in Minnesota are beyond the jurisdiction of the NDPSC.

20
21 **Q. Is the analysis of the Data Center retail load relevant to North Dakota if it is beyond
22 the jurisdiction of the NDPSC?**

23 A. Yes, it is relevant with regards to understanding the actual expected rate savings
24 associated with Dakota Range III that will be realized by NSP's North Dakota customers
25 after consideration of expected associated new load as well as potential transmission
26 costs.

27

⁵ The MPUC is reviewing a Retail Electric Service Agreement (ESA), a Competitive Rate Response Rider (CRR), and an Interconnection Agreement (IA).

1 **Q. Have you provided an analysis for the Commission which considers the Data Center**
2 **load to be simply additional organic load growth for the Company?**

3 A. Yes. I believe it is appropriate for the Commission to consider the impacts of the Data
4 Center load for reasons discussed earlier in my testimony. However, should the
5 Commission wish to consider the Data Center load to be natural load growth that the
6 Company has an obligation to serve, the analysis in Section XI of my testimony
7 addresses this view and evaluates the economics of the proposed PPA independently of
8 the load addition.
9

10 **V. Summary of Dakota Range III PPA**

11

12 **Q. Would you please provide an overview of the PPA?**

13 A. The PPA for Dakota Range III is a twelve-year contract to sell the entire output to NSP
14 for a fixed price over the contract term. Dakota Range III is responsible for procuring the
15 transmission interconnection as well as responsible for all interconnection costs. The
16 anticipated COD is no later than December 31, 2020. The contract contains provisions for
17 payments from NSP for certain types of curtailments, “Compensable Curtailments.”
18 Additionally, NSP has Rights of First Offer should Dakota Range III be offered for sale.
19

20 **Q. What are Compensable Curtailments?**

21 A. Compensable Curtailments under Section 8.3 of the PPA include “economic curtailments
22 and curtailments caused by negative LMP.”⁶
23

24 **Q. Has the Company estimated the amount of Compensable Curtailments?**

25 A. No. In the Company’s response to Data Request No. NDPSC1-014, the Company
26 indicated that it used a conservative assumption regarding the limits of how much power

⁶ Section 8.3 (B) 1 (ii) Wind Energy Purchase Agreement between Northern States Power Company, a Minnesota Corporation and Dakota Range III, LLC.

1 can be exported based upon transmission constraints. Further, no specific constraints
2 were assigned to the Dakota Range III project in the Strategist modeling. The Company
3 in a separate analysis estimated that the curtailments would start at [Trade Secret
4 Begins...] [REDACTED].⁷ [...Trade Secret Ends]
5 However, I note that the analysis does not distinguish between compensable and non-
6 compensable curtailments.

7
8 **Q. What is the amount paid for a compensable curtailment?**

9 A. NSP's application identifies a price of [Trade Secret Begins...] [REDACTED] [...Trade
10 Secret Ends].⁸

11
12 **Q. Is NSP's agreement with Dakota Range III subject to the approval of the NDPSC?**

13 A. NSP has the right to terminate the PPA if the NDPSC does not approve the requested
14 "Non-Jurisdictional Regulatory Treatment".⁹ The non-jurisdictional treatment refers to
15 the Commission agreeing that the energy and capacity from Dakota Range III will not be
16 used to serve North Dakota customers and the costs will not be charged to, or reimbursed
17 by North Dakota customers.

18
19 **Q. Has NSP requested non-jurisdictional treatment from the NDPSC?**

20 A. NSP in its application has indicated that it is proposing to treat Dakota Range III as a
21 system resource and therefore North Dakota customers would share in the costs and
22 anticipated benefits from the wind project. NSP notes that should the Commission
23 disapprove the ADP then it proposes that it the resource be removed from the FCR. I
24 discuss the proposed treatment, should the Commission reject the ADP, later in my
25 testimony.

26

⁷ NSP response to NDPSC-3-001 Alt A_Model_Reference_Case.

⁸ NSP Application p 8

⁹ NDPSC Data Request No. 1-5 Attachment A p 17 [confidential]

1 **VI. Summary of Data Center Retail Electric Service Agreement**

2
3 **Q. Would you please provide an overview of the Data Center RESA?**

4 A. NSP has negotiated a long-term contract to serve a new Google data center to be built on
5 315 acres of land that is currently part of the Sherco coal plant. (There is a separate
6 agreement to sell some of the Sherco land to Google.) Under the terms of the RESA,
7 NSP will procure incremental renewable resources that on an annual basis produce
8 enough energy to serve the data center. [Trade Secret Begins] ██████████
9 ██████████ [Trade Secret Ends] that allow some flexibility in
10 matching the annual incremental renewable energy production with the annual data
11 center loads. The renewable energy credits associated with the incremental renewable
12 resources will be retired for the benefit of Google in the amounts that match the data
13 center load. In addition, depending on the peak load of the data center, there is also a
14 provision for matching the peak demand with the capacity of the incremental renewable
15 resources.

16
17 **Q. What is the term of the RESA?**

18 A. The initial term is ten years with provisions for extension.
19

20 **Q. How does NSP plan to meet the requirement for incremental renewable resources?**

21 A. NSP plans to acquire approximately 300 MW of incremental wind generation to serve the
22 anticipated energy requirements in the first phase of the data center build-out. Dakota
23 Range III is the first phase of that procurement.
24

25 **Q. Does the Google RESA have specific commitments with regard to its contracted
26 demand or minimum energy requirements?**

27 A. No. There are confidential load forecasts as well as an expected capacity factor associated
28 with the load but no specific load commitments. Given that the pattern of the load growth
29 is uncertain, there is also some flexibility built into the contract regarding the timing for
30 meeting the annual energy requirements with incremental renewable resources.

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Q. Will NSP have to build new transmission facilities to serve the Data Center?

A. Yes. The Data Center will be served at transmission level voltage and NSP will be responsible for the costs associated with constructing a substation and transmission that will connect with the Data Center. NSP has developed estimates for these costs separated into four phases where each phase is associated with increments in the Data Center's peak demand. The first phase is anticipated to meet the load requirements in the initial term of the RESA.

Q. Will North Dakota customers be responsible for the recovery of a share of the cost of the new transmission facilities?

A. Potentially. Based upon the Company's response to Data Response NDPSC 2-4, any costs that are defined as network costs will be proportionately allocated to North Dakota.

Q. Will North Dakota customers benefit from the sale of Sherco land to Google?

A. Potentially. NSP has noted that they anticipate a gain on the land sale, but has not provided any additional detail on this point.

Q. Is the RESA conditioned on approval of the NDPSC?

A. Article 6-3 of the RESA addresses termination for failure of regulatory approvals including the NDPSC. My non-legal interpretation is that the Company would have the right to terminate if it did not get approval from the NDPSC or approval with substantially equivalent economic terms. However, the Company may choose to waive those requirements.

VII. Evaluation of the ADP Application

Q. Please provide an overview of your analysis of the ADP application?

1 A. My assessment of the Project addresses three fundamental questions:

- 2 • First, is there a need for the project with regard to serving NSP's load?
- 3 • Second, will the project lower energy and capacity costs for NSP's North Dakota
- 4 customers?
- 5 • Third, what are the impacts of adding the data center load on the allocation of
- 6 fixed generation costs using the 12CP methodology?
- 7

8 The analysis of whether the Project will lower energy and capacity costs is further
9 divided into two scenarios:

- 10 1) The economics of Dakota Range III without incorporating the estimated data
- 11 center load; and
- 12 2) The economics of Dakota Range III incorporating the estimated data center
- 13 load.
- 14
- 15

16 Q. **How did you frame the analysis of Dakota Range III with the expected Data Center**
17 **load?**

18 A. The Data Center's initial load and its growth are uncertain, so it was necessary to make
19 associated assumptions about both. In addition, I incorporated an adjustment; while the
20 ADP request is specifically related to the Dakota Range III project, the Company is
21 expecting to add an additional approximately 150 MW of wind to meet the RESA terms
22 of securing incremental renewable generation to serve the data center in the initial term of
23 the RESA.

24
25 Q. **What did you assume for the Data Center load in your analysis?**

26 A. NSP estimates that over the initial ten-year term of the contract the Data Center load will
27 be [Trade Secret Begins...] [REDACTED] [...Trade Secret Ends] load factor.
28 Based upon scenarios that the Company developed in conjunction with its Minnesota
29 PUC filings, I concluded that a reasonable base case assumption is that the load starts at
30 [Trade Secret Begins...] [REDACTED]
31 [REDACTED] [...Trade Secret Ends] Because the company is targeting approximately

1 150 MW of additional wind, I assumed that the Data Center load that would be served by
2 the Project would be [Trade Secret Begins...] [REDACTED]
3 [REDACTED]. [...Trade Secret Ends]

4
5 **Q. Would you please explain the assumed relationship between the amount of wind**
6 **energy acquired and the Data Center load?**

7 **A.** The Dakota Range III project has an expected capacity factor of [Trade Secret Begins...]
8 [REDACTED] [...Trade
9 Secret Ends] NSP is required to procure incremental renewable generation to meet the
10 Data Center load. At the Data Center's expected load factor, [Trade Secret Begins...] [REDACTED]
11 [REDACTED] [...Trade Secret Ends] load translates into an annual energy usage of [Trade
12 Secret Begins...] [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED] [...Trade Secret Ends]

16
17 **Q. Would you please explain the assumed relationship between the amount of**
18 **accredited capacity acquired from Dakota Range III and the data center load?**

19 **A.** The Dakota Range III project has a nameplate capacity of 151.2 MW. However, the
20 MISO accredited capacity is expected to be approximately 22.9 MW. Based upon the
21 previously discussed assumed data center load, I estimate that by the end of year [Trade
22 Secret Begins...] [REDACTED] [...Trade Secret Ends] there is an incremental capacity
23 requirement up to a total capacity of [Trade Secret Begins...] [REDACTED] [...Trade Secret
24 Ends] at the end of year ten. The result is that the Data Center creates an incremental
25 system capacity requirement.
26

27 **VIII. Need Assessment of the Project**
28

29 **Q. Does the Company need the Project to meet its capacity requirements?**

1 A. The Company does not project an immediate capacity need. In the Company's Strategist
2 base case load forecast, which does not consider the additional Google Data Center load,
3 new capacity resources are not added to the system until 2027 when the model adds a 374
4 MW combustion turbine in addition to a combined cycle project. The Dakota Range III
5 defers the need for the 374 MW CT until 2030 to 2031.¹⁰
6

7 **Q. Why should the Commission grant an ADP for the project?**

8 A. The Project is expected to lower the Company's system average cost, consequentially the
9 Project is considered "least cost".
10

11 **Q. How does the proposed Project impact the Company's capacity mix from a resource
12 diversity perspective?**

13 A. The project is not expected to significantly change the Company's capacity mix. The
14 Dakota Range III project is expected to add approximately 22.9 MW of accredited
15 capacity.¹¹
16

17 **Q. How does the proposed Project impact the Company's energy mix from a resource
18 diversity perspective?**

19 A. The Company's Strategist analysis base case includes the recently approved 1,550 MW
20 of wind plus the Dakota Range I & II projects. As shown in the following tables, the
21 Dakota Range III project does not significantly change the generation mix.
22

¹⁰ Attachment A, PU-18-430 NDPSC 1-011.

¹¹ NSP Response to NDPSC-02-006.

1 **Table 1: GWH Resource Mix* without Dakota Range III**

Resource Type	2019	2020	2022	2025	2030
Coal	32%	26%	19%	16%	10%
Nuclear	27%	25%	18%	18%	17%
Gas	13%	14%	10%	11%	10%
Hydro	5%	4%	3%	4%	4%
Wind / Solar	22%	30%	49%	52%	59%
Other	2%	2%	1%	1%	0%

2 * Table excludes system purchases

3
4 **Table 2: GWH Resource Mix* with Dakota Range III**

Resource Type	2019	2020	2022	2025	2030
Coal	32%	26%	18%	15%	9%
Nuclear	27%	25%	18%	17%	17%
Gas	13%	14%	10%	10%	10%
Hydro	5%	4%	3%	3%	4%
Wind / Solar	22%	30%	50%	53%	59%
Other	2%	1%	1%	1%	0%

5 * Table excludes system purchases

6
7 **IX. Evaluation of the Company's Economic Analysis of the Project**

8
9 **Q. How did the Company evaluate the proposed Project's impacts on its system costs?**

10 **A.** The Company conducted planning studies using the Strategist resource planning model to
11 evaluate the projected impact on its system costs. In projecting the economic dispatch of
12 each NSP resource, Strategist simulates the operation of the NSP System and estimates
13 the total system costs impact of the Project on a present value basis.

14
15 **Q. Do you believe that Strategist is limited in its ability to accurately evaluate the
16 economics of adding wind generation to the Company's system?**

17 **A.** Yes. Strategist has limitations, particularly with respect to the evaluation of wind and
18 solar resources. However, even while acknowledging Strategist's shortcomings in
19 accurately representing both system load and intermittent generation facilities, the
20 Company's analysis demonstrates that the proposed Project will provide savings for the

1 Company's customers, absent consideration of the Data Center load.
2

3 **Q. Did you review the Company's Strategist modeling?**

4 **A.** Yes. Specifically, I reviewed the following:

- 5 • The natural gas and wholesale electric market price assumptions used in the
6 model; and
- 7 • The results of the planning scenarios the Company conducted via Strategist.
8

9 **Q. Would you please summarize the scenarios that the Company evaluated using
10 Strategist?**

11 **A.** Yes. The Company developed scenarios designed to evaluate the sensitivity of the Project
12 and its impact on the Company's system to varying assumptions such as high and low
13 system loads and natural gas prices. Because power prices and natural gas prices are
14 highly correlated in the MISO market, the natural gas sensitivities also incorporated
15 higher and lower market prices.
16

17 Additionally, the Company evaluated three different energy markets-based scenarios:
18

- 19 1) The Base or Reference case "Markets On" scenario assumed that the
20 Company does and will continue to make daily sales and purchases to and
21 from the MISO market;
- 22 2) The "Markets Off, no dump energy credit" scenario assumed that the
23 Company *does not* make daily sales and purchases to and from the MISO
24 market, and no value is given to any generation in excess of the Company's
25 load requirements; and
- 26 3) The "Markets Off, dump energy credit" scenario assumed that the Company
27 *does not* make daily sales and purchases to and from the MISO market, and
28 any generation in excess of the Company's load requirements is valued at half
29 of the projected market energy price.

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Q. Do you consider the “Markets Off” scenario cases to be relevant for this Commission to consider?

A. No. The Markets Off scenarios assume the Company does not have access to buy and sell power in the MISO market. This does not reflect reality as the Company buys and sells power in the MISO market every day. My understanding is that the Markets Off scenarios were developed for the MPUC.

Q. How will the Project earn revenues in the MISO market?

A. The Project will earn revenues based upon bidding into the MISO market and receiving the market clearing price for its generation. The market clearing price will reflect congestion and losses allocated to each generator’s interconnection node.

Q. Does the Strategist model create the forecasts of the market prices?

A. No. The market prices are an exogenous input to Strategist; the market prices used by the Company are inputs to the model.

Q. Are the market electricity prices impacted by natural gas prices?

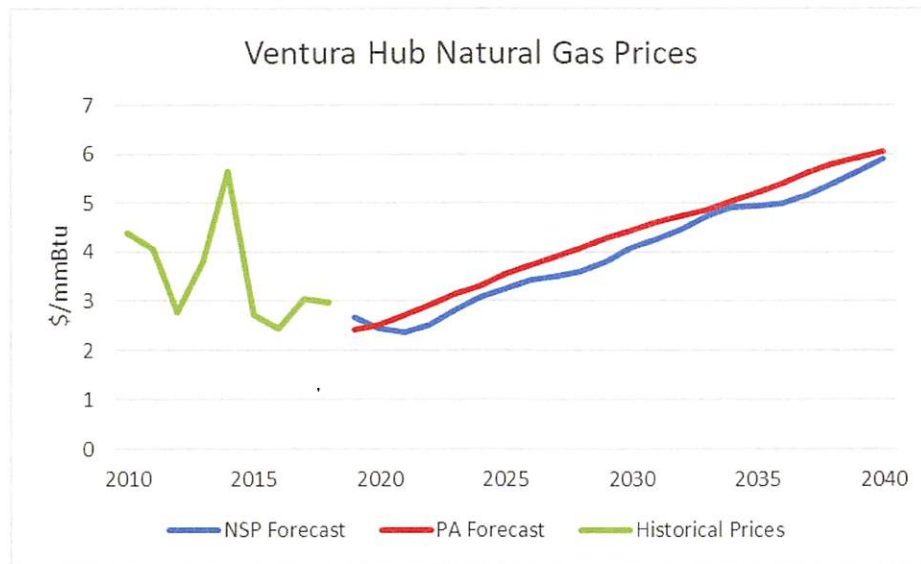
A. Yes. When natural gas-fired generation units are the marginal units setting market prices, there is a strong relationship between gas prices and power prices. The MISO Market Monitor reports that over the last 13 months, the correlation coefficient between the Henry Hub natural gas price and the MISO Real Time Locational Marginal Price was 0.84.¹²

Q. How does the Company’s forecast of natural gas prices compare to historical prices and other forecasts?

¹² MISO May 2018 Monthly Market Assessment Report, Market Evaluation and Design, July 12, 2018, p 16.

1 A. The natural gas price forecast appears reasonable. I compared the Company's delivered
2 natural gas price forecast for the Ventura pricing hub in Minnesota with that of PA's
3 forecast for the hub. The Company's forecast is generally slightly lower than PA's
4 forecast, which would tend to slightly decrease the associated market prices and projected
5 benefits of the Project.
6

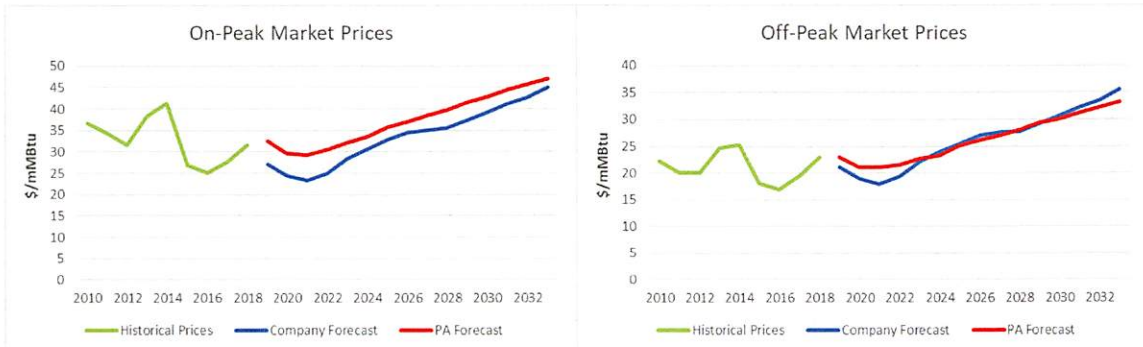
7 **Figure 1. PA Natural Gas Price Forecast vs. NSP Forecast (\$/MMBtu)**



8
9
10 **Q. How does the Company's forecast of MISO power prices compare to PA's forecast?**

11 A. The Company's MISO power prices forecast generally follows the same trend as PA's
12 and is slightly lower than PA's forecast over the PPA term, as shown in Figure 2 below. I
13 find the Company's forecast to be reasonable and I would expect that the Company's
14 Strategist results are a reasonable projection of the Project's value to the NSP system.
15

Figure 2. MIN HUB Historical and Forecast Prices (\$/MWh)



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4 **Q. How is the capacity of the Project valued in the economic analysis?**

5 **A.** The value of the capacity is embedded in the Strategist analysis. In the near-term, the
6 Company has excess capacity relative to its peak demand and reserve capacity
7 requirements. In these years the Strategist analysis credits the Project with incremental
8 value of its contribution to the excess capacity. The Project is expected to provide
9 approximately 23 MW of firm capacity value to the system.
10

11 **Q. Does the economic analysis include any assumption regarding wind integration
12 costs?**

13 **A.** Yes. To account for the intermittency of the Project's generation output and the costs the
14 Company incurs to maintain a balanced system, the Strategist analysis included an
15 additional adder to the Project's PPA price. Adding such a wind integration charge when
16 evaluating the economics of wind energy is an industry accepted general practice, and I
17 believe the Company applied it appropriately in the Strategist analysis.
18

19 **Q. What did you conclude regarding the Company's economic analysis of the Project?**

20 **A.** I concluded that the Company's Strategist analysis was reasonably conducted. While I
21 did not conduct a parallel Strategist analysis, I conducted a thorough review of the
22 Company's analysis and found the input assumptions and output results to be reasonable.
23

24 However, as noted throughout my testimony, I believe that the Company's initial

1 Strategist analysis as described in the Application portrays an incomplete picture of the
2 economics of the Project. I believe that only by considering both the Project as well as
3 the Data Center RESA can the Commission get a complete understanding of the impacts
4 of the Project on North Dakota ratepayers.
5

6 **X. Evaluation of NSP's Supplemental Strategist Runs**

7 **Q. Did Advocacy Staff request NSP to develop additional Strategist model runs?**

8 A. Yes, the Company's Strategist modeling and different scenarios included in the ADP
9 Application and associated direct testimony evaluated the savings of the PPA while
10 excluding the anticipated Data Center load. For example, the only difference between the
11 reference case run and the reference case with the PPA run is the inclusion of the PPA.
12 Even in the high load case, the load is the same with, and without the PPA. Advocacy
13 Staff in Data Request NDPSC 2-008 requested that the Company develop new model
14 runs in which the cases with the PPA also include a commensurate amount of load
15 associated with the Data Center.
16

17 **Q. Did NSP change any other assumptions besides adding the incremental load?**

18 A. Yes. In the Supplemental analysis, the Company and Advocacy Staff agreed that it was
19 appropriate to increase the transfer capacity out of MISO Zone 1 from 1,350 MW to
20 1,800 MW based upon the Company's analysis that the transfer capacity used in the
21 initial runs was overly conservative given anticipated transmission system enhancements.
22 The impact of increasing the transfer capacity is to reduce the amount of dump energy in
23 the model and allow more generation to be sold into the market. One consequence of this
24 change is that the reference case (no PPA) used in the response to Data Request NDPSC
25 2-008 is different than the reference case in the pre-filed direct testimony.
26

27 **Q. Did adding the Data Center load accelerate the NSP system need for capacity?**

1 A. Yes, the combined impact of adding the PPA and the data center load accelerated the
2 need to add one 331 MW CT from 2030 to 2028.¹³
3

4 **Q. What are the economic results of the Company's Supplemental analysis?**

5 A. The results of the analysis were that when including both the PPA and the Data Center
6 load, the system PVRR increased but that there was still a PVRR [Trade Secret
7 Begins...] [REDACTED] [...Trade Secret Ends] savings to NSP's North Dakota customers as a
8 result of changes to the capacity allocation factor associated with adding more load to
9 Minnesota.¹⁴
10

11 **Q. Do you agree that revised estimated savings to North Dakota are reasonable?**

12 A. Yes, I think the estimated savings are reasonable. However, I made an adjustment to the
13 logic of how NSP allocated costs to North Dakota and that adjustment lowers the savings
14 further. I did not complete a detailed review of the Strategist modeling but based upon a
15 simplified model that I developed, my conclusion is that the Company conducted the
16 modeling correctly. My concern is that the calculation of the savings is based upon
17 allocating the annual value of the revenue requirement calculated in Strategist in each
18 year based upon the assumed 12 CP capacity allocation factor. My concern is that only
19 generation demand related costs should be allocated on the 12CP capacity allocation
20 factor, while the fuel and purchased power costs should be allocated on a loss adjusted
21 energy sales allocation factor. I did not have information on how to divide the annual
22 revenue requirement from Strategist into energy and demand. Therefore, I used FCA
23 filings to estimate an energy allocation factor and a percentage of the total Strategist
24 PVRR that should be allocated on energy and the percentage that should be allocated on
25 demand. Based upon this adjustment, the resulting savings to NSP's North Dakota
26 customers is [Trade Secret Begins...] [REDACTED] [...Trade Secret Ends] depending

¹³ NSP Public Response to NDPSC 2-008.

¹⁴ NSP confidential response to NDPSC-2-008.

1 on the assumption of how often there are rate cases that will cause the demand allocation
2 factor to be updated. My calculations are provided in Exhibit JAH-3.
3

4 **Q. Do you have any other concerns with estimating the savings based upon a capacity**
5 **allocation factor?**

6 A. Yes, my understanding is that the capacity allocation factor is used to allocate generation
7 demand costs in conjunction with general rate cases. The factor is not updated or used in
8 the FCA. The Company's estimated savings assumes that the capacity allocation factor
9 changes every year. In the Company's model, the North Dakota jurisdiction's share of
10 costs decreases each year due to the assumptions surrounding the data center's load
11 growth. For example, if the Company had a rate case in 2023 for rates in 2024 but then
12 did not have a rate case until 2030, those six years of Minnesota load growth would not
13 result in any associated reduction in the non-fuel and purchased power costs allocated to
14 North Dakota via the 12CP capacity allocation factor.
15

16 **Q. Based upon your evaluation of the NSP analysis, do you conclude that there will be**
17 **material savings to North Dakota customers after accounting for the RESA?**

18 A. No, the identified savings are not material given the inherent uncertainties in any long-
19 term forecasts and also giving consideration for the risk of curtailment or payments by
20 the Company for compensable curtailments.¹⁵ There are also other potential costs
21 including procurement of any shortfall of RECs needed to meet the Data Center load,
22 lower wind energy production as a result of outages or environmental conditions, and any
23 increases in transmission costs allocated to North Dakota as a result of any of the
24 transmission improvements associated with serving the Data Center being classified as
25 network resources.
26
27

¹⁵ NSP response to NDPSC-1-014 (c)

1 **XI. Independent Economic Analysis of the Project**
2

3 **Q. Would you please summarize your independent economic analysis of the Project?**

4 A. Yes. While the Company's Strategist analysis sought to evaluate the Project as a resource
5 integrated into the NSP system, I took an alternate approach to evaluate the project as a
6 MISO energy market participant.
7

8 **Q. Would you please describe the foundation of your economic analysis?**

9 A. Yes. Using the Aurora XMP hourly chronological dispatch model, PA developed a long-
10 term forecast of monthly on- and off-peak MN Hub prices. I used those prices in
11 conjunction with the hourly wind production profile to estimate the revenues that the
12 Company will receive from dispatching the Dakota Range III project into the MISO
13 market. I compared the estimated revenues with the Project's PPA costs and additional
14 costs related to Compensable Curtailment and wind integration costs.
15

16 **Q. Did you evaluate the impact of changes in production resulting from curtailment or
17 deviations from expected performance?**

18 A. Yes. The Company indicated expected curtailments of approximately [Trade Secret
19 Begins] [REDACTED]
20 [REDACTED] [Trade Secret Ends] Further, the Company indicated
21 that the price of these curtailments was approximately [Trade Secret Begins] [REDACTED]
22 [Trade Secret Ends]. My analysis incorporated these curtailment costs.
23

24 **Q. Does your economic analysis consider any other costs of the Project, such as wind
25 integration, wind congestion, or wind-induced coal plant cycling costs?**

26 A. Yes. In the Company's Application, Mr. Martin's testimony provided assumptions which
27 were incorporated into the Company's analysis related to wind integration and wind
28 congestion costs. My analysis incorporated these assumptions.
29

1 **Q. Does the economic analysis include any valuation of environmental or economic**
2 **development benefits?**

3 **A.** No, neither environmental nor economic development benefits are incorporated into the
4 estimated ratepayer savings to ratepayers.
5

6 **Q. Did you conduct any scenario or other sensitivity analyses of the Project?**

7 **A.** Yes. In addition to my base case analysis, I also conducted a similar analysis which
8 assumed that the MISO market experiences a significant increase in renewable
9 generation.
10

11 **Q. On what did you base your assumptions for this High Renewables scenario?**

12 **A.** I based the increased renewable generation levels in MISO upon the MISO Transmission
13 Expansion Plan (MTEP) Futures planning process. The MTEP20 Futures are currently
14 under development by the MTEP Planning Advisory Committee. Based on an April 2019
15 planning document, I created the High Renewables scenario by assuming that MISO
16 renewables reach the minimum renewable penetration levels (40%) associated with the
17 most aggressive MTEP20 Futures case, the Accelerated Fleet Change case.
18

19 In simple terms, what this means is that my High Renewables scenario assumes that
20 MISO as a whole reaches a minimum of approximately 40% renewable generation by
21 2033. In the case of the Company's MISO Zone 1, this resulted in the High Renewables
22 scenario assuming that Zone 1 reaches approximately 75% renewable generation within
23 fifteen years.
24

25 **Q. Why do you think this scenario is relevant for the Commission to consider?**

26 **A.** I have concerns that while the proposed PPA's pricing terms are attractive to the
27 Company when compared to today's market prices, it's possible that as additional low-
28 cost renewables are added to the MISO system, market prices will likely become
29 depressed, which would reduce the potential savings associated with the Project. To
30 evaluate this possible "downside" case, I created the High Renewables scenario.

1
2 **XII. Assessment of the Projected Energy Cost Savings of the Project**
3

4 **Q. Could you please compare your estimates of the projected energy cost savings to the**
5 **Company's estimates?**

6 **A.** Yes, Table 3 below summarizes my comparison. The Company's Strategist analysis of
7 the Project as an integrated NSP system resource (excluding considerations of the costs to
8 serve the data center's load, as described above) estimates approximately \$22M in
9 present value, total system cost savings. My independent analysis of the Project estimates
10 approximately \$48M in present value total system cost savings under base case market
11 conditions. When considering the potential for significantly higher renewable generation
12 in MISO, my analysis indicates the potential present value total system cost savings are
13 reduced to approximately \$31M. Annual savings are provided in Exhibit JAH-2.
14

15 **Table 3.** Independent Economic Analysis Results

	NSP Strategist Analysis	PA Base Case Analysis	PA High Renewables Analysis
Present Value System Cost Savings (\$M)	22	48	31

16
17 **Q. What are your conclusions with regard to the Company's estimate of \$22 million of**
18 **system cost savings from the Project?**

19 **A.** My conclusion is that the Project is likely to result in electricity cost savings to North
20 Dakota customers absent consideration of the data center load. Given the uncertainties
21 inherent in modeling electric systems, I find the variance between the Company's
22 analysis and my base case independent analysis conclusion of \$48 million in present
23 value total system cost savings to be reasonable, and both indicate the likelihood of
24 system cost savings for NSP customers.
25

26 Comparing my High Renewables scenario results of approximately \$31 million of
27 present value total system cost savings to my estimated base case present value of savings

1 of approximately \$48 million in savings, I find that it's reasonable to expect a significant
2 reduction in estimated savings due to market prices being depressed due to the high
3 penetration of lower cost renewables which were assumed in the scenario.
4

5 As discussed above, the Commission's consideration of the ADP Application should
6 consider not only the economic benefits of the Project itself, but the wider implications of
7 the Project and the Data Center RESA in combination.
8

9 **Q. How would North Dakota customers be impacted by the Project in the hypothetical**
10 **case that the Data Center was not considered a discrete customer addition by the**
11 **Company, but rather be considered as a normal load growth?**

12 A. This hypothetical case is addressed in the analysis presented in Section XI of my
13 testimony. Section XI evaluates the Project as purely a market participant without
14 considering any Minnesota or North Dakota loads. In the hypothetical case, the Data
15 Center load would be not considered in the Commission's evaluation, and the impact of
16 the Project would be irrespective of the load. This is essentially the same analysis as if
17 the Project were purely a market participant.
18

19 **XIII. Allocation of Generation Demand Costs**

20

21 **Q. Have you evaluated NSP's finding that North Dakota customers will benefit in the**
22 **allocation of generation demand costs as a result of adding the Data Center load?**

23 A. Yes. In Table 3 of Mr. Martin's testimony, he presented an analysis illustrating how
24 adding the data center load changes the 12 CP demand cost allocation factor, which
25 would result in shifting a greater parentage of generation costs classified as demand to
26 Minnesota.
27

28 **Q. Do you expect that there will be demand cost savings for North Dakota's customers**
29 **based upon your review of Mr. Martin's analysis?**

1 A. I anticipate that there will be minimal savings in the early years of the contract. However,
2 I do not expect that there will be savings after the first few years depending on the load
3 growth of the Data Center. In addition, the demand cost allocation will not change until
4 the next general rate case in North Dakota. Finally, I note that the use of the 12CP
5 allocation factor was an issue in the past general rate case, and the settlement in that rate
6 case Advocacy Staff agreed to support the 12CP through 2025. In any general rate case
7 after 2025, the demand cost allocator might be revised and therefore the benefits
8 attributable to North Dakota customers of adding the data center would also be revised at
9 that point.
10

11 **Q. Why are you not anticipating demand cost savings after the first few years?**

12 A. After the first few years I expect that the demand cost allocation factor would continue to
13 decrease the percentage of the generation demand costs allocated to North Dakota.
14 However, after the first few years the amount of demand costs will increase as the peak
15 load of the data center exceeds the accredited capacity of Dakota Range III. This should
16 result in either less surplus capacity to sell in the earlier years and in the later years
17 accelerating the need for a new combustion turbine.
18

19 **XIV. Accounting for Fuel & Purchase Power Cost if ADP is**
20 **Rejected**
21

22 **Q. Would you please summarize the Company's proposal for addressing the costs of**
23 **Dakota Range III if the Commission rejects the ADP?**

24 A. The Company proposes a treatment like the precedent for treating other historical
25 disputed PPAs. This treatment involves removing the cost of the PPA from the power
26 cost for the Fuel Cost Rider (FCR) period and replacing that cost with an equivalent
27 amount of energy purchased at the average system cost.
28

1 **Q. Do you recommend that the Commission adopt the Company's proposed treatment**
2 **should the ADP be rejected?**

3 A. No. The precedent was designed, in part, to address the Company's signing PPAs for
4 expensive renewable resources that would raise the average fuel and purchased power
5 costs. The treatment protected NSP's North Dakota customers from paying higher power
6 costs driven by resource procurement policies in other states. Based upon my analysis,
7 my conclusion is that substituting average power costs for the Dakota Range III project
8 would result in increasing the average fuel and purchased power costs for North Dakota.
9 My recommendation is that the Commission consider an alternative approach given that
10 although NSP is proposing to treat Dakota Range III as a system resource, it is being
11 acquired to serve the Google RESA.

12
13 **Q. What is your proposed alternative approach?**

14 A. My proposal is to not only remove the PPA from the fuel and purchased power, but also
15 remove the load of the data center in the calculation of average system fuel and
16 purchased power costs.

17
18 **Q. What is your rationale for incorporating the data center load in the FCR if the ADP**
19 **is rejected?**

20 A. I consider the data center load to be discretionary and an integral part of the decision to
21 execute the PPA for Dakota Range III. Based upon my review of the Google RESA and
22 the filing in Minnesota requesting approval of three agreements related to the Google
23 retail load, I have concluded that Minnesota and NSP actively sought to attract the data
24 center load and offer special pricing to attract the load. From the Minnesota perspective
25 there appear to be benefits to Minnesota in the form of economic development and
26 obtaining marginal revenues for Minnesota NSP customers that exceed the marginal costs
27 of the electric service. However, North Dakota does not directly share in those economic
28 development benefits or the increased retail revenues.

1 **Q. Do you have an alternative proposal for addressing Dakota Range III in the FCR if**
2 **the ADP is rejected?**

3 A. Yes. However, I recognize that there are numerous potential approaches and that this
4 proceeding may not be the appropriate place to address the issue. One approach is to
5 exclude both the data center load and the PPAs secured to serve the data center load. This
6 would be done in a three-step process that I would expect to be reasonable to implement.

7
8 The first step is to remove the cost of the PPA from NSP's fuel and purchased power
9 costs. This is the same first step used to address the disputed PPAs. The second step is to
10 remove the marginal benefits and costs associated with the PPA from the total remaining
11 power costs. The marginal cost and benefits are calculated based upon the hourly
12 production from the Project and the hourly load of the Data Center. Energy from the
13 Project is sold to the market, resulting in extra power sales revenues that would not have
14 occurred but for signing the PPA and the Google RESA.

15
16 Similarly, the cost of serving the Data Center's load is based upon purchases from the
17 MISO market, resulting in incremental costs that would not have been incurred but for
18 the PPA and the RESA. Sales should be valued at the Dakota Range III's hourly nodal
19 price and Purchases to serve the load should be valued at the Minnesota Hub price. The
20 hourly sales and costs would be summed over the FCR period. If the total is positive net
21 benefits, that cost would be added to the adjusted total costs calculated in the first step.
22 The benefits would be removed since North Dakota would not get a share of the benefits
23 having rejected the ADP. Likewise, if the total is negative net costs, those costs would
24 be subtracted from the adjusted total costs so that North Dakota is not penalized for the
25 added system costs of serving the data center.

26 The third step is to remove the data center load from the total sales to calculate the
27 adjusted average power costs for the FCR period, which would be compared with the
28 average cost recovered in rates in order to calculate the appropriate FCR adjustment.
29

1 **Q. Would your proposal always result in lowering the energy and fuel costs allocated to**
2 **North Dakota?**

3 A. No. In the early years when the electricity purchased under the PPA is significantly
4 greater than the data center load, there is likely to be a net reduction in average power
5 costs and North Dakota would not share in that benefit. In later years, when the load of
6 the data center exceeds the power produced by the Project there would be a reduction in
7 the average power costs. The amount of the adjustment is a function of both the Data
8 Center loads and the difference between the PPA and Minnesota Hub prices.
9

10 **XV. Other Considerations**

11

12 **Q. Did you consider any other issues related to the Project in making your**
13 **recommendations?**

14 A. Yes. I have comments related to:

- 15 • The relationship of the procurement of the Dakota Range III PPA and the
 - 16 Company's Integrated Resource Plan (IRP);
 - 17 • Consideration of what happens after the end of the PPA and the initial term of the
 - 18 Google RESA; and
 - 19 • Treatment of the renewable energy credits (RECs).
- 20

21 **Q. How does the procurement of the PPA relate to the NSP IRP?**

22 A. I understand that there is a timing issue. If one evaluates the Application and the PPA as
23 filed, the justification is to lower power costs, as opposed to being procured to meet the
24 requirements of the contract with Google. From this perspective the Commission is being
25 asked to make a resource procurement decision prior to reviewing the Company's IRP
26 and its associated long-term resource procurement plan that is expected in the summer of
27 2019.
28

1 **Q. Do you anticipate that the PPA will be found to be cost effective in the 2019 NSP**
2 **IRP?**

3 **A.** Yes, the PPA is a low-cost wind resource relative to the Company's current system.
4 However, the relative savings compared to market purchases may be lower than
5 forecasted based upon factoring in potential regional procurement policies that may be
6 reflected in the IRP, such as Minnesota moving to 100% renewables by 2050 or Xcel's
7 goal to have carbon emissions 80% below its 2005 level by 2030.¹⁶
8

9 **Q. What are the cost implications of serving the Data Center after the termination of**
10 **the PPA?**

11 **A.** The PPA has a term of twelve years and NSP has negotiated a ten-year rate for the Data
12 Center (subject to MPUC approval). However, at the end of the ten-year rate agreement,
13 NSP will have an obligation to serve the anticipated growing load of the Data Center at a
14 rate subject to negotiation and MPUC approval.¹⁷¹⁸ While the NDPSC is not involved in
15 the retail rate, the impact on serving the Data Center load beyond the term of the PPA
16 was not modeled or analyzed in this proceeding. The Data Center load in NSP's high
17 growth rate starts at [Trade Secret Begins] [REDACTED] [Trade Secret Ends] in year ten
18 and could grow from there. The Data Center load, the cost of serving the load after the
19 ten-year extension, and the total system loads represent significant unknowns. It is
20 difficult to draw a conclusion regarding the long-term impacts of the Data Center on
21 North Dakota power costs. However, the Commission should be aware that there are
22 long-term implications arising from its decision on whether or not the PPA and the data
23 center are treated as non-jurisdictional.
24

25 **Q. What are your concerns regarding the RECs?**

¹⁶ Building a Carbon-Free Future, Xcel Energy Carbon Report 2019.

¹⁷ NSP Petition Contracts for Provision of Electric Service to Google's Minnesota Data Center Project
Docket No. E002/m-19-___, p 20.

¹⁸ The Retail Electric Service Agreement states that negotiations to extend the initial ten-year contract term
will include the principles of recognition of the customer's investment in the Data Center and the Company's
obligation to serve. Section 3.2 Good Faith Negotiations for Extension, December 12, 2018.

1 A. I have two concerns. First NSP is requesting that the PPA is treated as a system resource.
2 However, the Company's proposal does not share the benefits of the RECs in a manner
3 comparable to other renewable resources included in the FCA. The second concern is the
4 potential liability if the PPA does not produce enough credits to meet the data center load.

5
6 **Q. Why is the Company's proposed treatment of the RECs inconsistent with other
7 renewable resources?**

8 A. The Company is proposing to retire all the RECs for the benefit of Google as opposed to
9 the current precedent of allocating a proportional share of the RECs to North Dakota
10 based upon the North Dakota load. Consequentially, my recommendation is that if the
11 Commission approve the ADP, that it requires the Company to credit North Dakota with
12 the monetized value of the North Dakota's share of the RECs.

13
14 **Q. What is your recommendation regarding the treatment of any RECs that the
15 Company may need to purchase to meet its obligations to Google?**

16 A. My recommendation is that should the Company have to purchase RECs due to having
17 insufficient incremental renewable generation to serve the entire data center load, that
18 none of those costs are allocated to North Dakota.

19
20 **Q. Does this conclude your testimony?**

21 A. Yes.