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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

61 PU-18-430 Filed 07/15/2019 Pages: 35
Exhibit 7 - Direct Testimony of James A. Heidell - redacted
Northern States Power Company

TABLE OF CONTENTS

I. Introduction

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

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

Q. On whose behalf are you filing this testimony?

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

Q. Please summarize your qualifications and experience.

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

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

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

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

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with my assessment of the Northern States Power Company's (NSP or the Company) request for an Advance Determination of Prudence (ADP) for the proposed Power Purchase Agreement (PPA) between the Company and the Dakota Range III Wind Project (Project).

The Company has applied (Application) for an ADP for the Project, indicating to the Commission that the Project is priced below the Company's system average cost and will therefore result in ratepayer savings. Additionally, in its Application the Company states that the Project's renewable energy attributes are needed in association with a separate Retail Electric Service Agreement (RESA) the Company has executed with a new electric service customer in Minnesota.[1]

My testimony provides the Commission with my evaluation of the Project's economics and associated impacts on the Company's North Dakota customers and ultimately my recommendation of whether or not the Commission should approve the ADP.

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

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

- A summary of my recommendations (Section II);

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[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.

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

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring three exhibits:

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

II. Summary of Recommendations

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

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

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

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

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

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

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

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

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

III. Summary of Findings

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

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

- The proposed PPA describes the terms and conditions under which the Company will purchase the output of the Project at below market pricing, which is expected to lower NSP's average fuel and purchased power costs compared with the Company's current system.
- After consideration of wind integration costs and potential curtailments, the PPA is expected to be a lower cost resource compared with the Company making wholesale purchases at Minnesota Hub prices.
- The PPA does not meet an immediate need for capacity as the first capacity resource added to the system in the reference case is a combustion turbine in 2027.

- As opposed to the PVRR savings of $22M in the Application, the PVRR will actually 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.

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

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

IV. The Impetus for the PPA

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

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

The primary impetus for the PPA is the Company's Retail Electric Service Agreement (RESA) with the Data Center to be located adjacent to the Sherco Power plant in Becker, Minnesota. The RESA is complex and the obligations of NSP are a function of the amount of load the Data Center will add to the system. However, at a high level NSP must procure incremental renewable resources to serve the Data Center load. In addition, the near-term expectation is that NSP will be procuring an additional 150 MW of wind to serve the anticipated load of the Data Center in its first ten years of operations.[3]

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

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

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

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

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[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.

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

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

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

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

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

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

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

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

V. Summary of Dakota Range III PPA

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

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

Q. What are Compensable Curtailments?

A. Compensable Curtailments under Section 8.3 of the PPA include "economic curtailments and curtailments caused by negative LMP."[6]

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

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

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

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

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

A. NSP's application identifies a price of **[Trade Secret Begins...]** [redacted] **[...Trade Secret Ends]**.[8]

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

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

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

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

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[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]

VI. Summary of Data Center Retail Electric Service Agreement

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

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

Q. What is the term of the RESA?

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

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

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

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

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

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?

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

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

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

1) The economics of Dakota Range III without incorporating the estimated data center load; and
2) The economics of Dakota Range III incorporating the estimated data center load.

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

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

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

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

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

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

A. The Dakota Range III project has an expected capacity factor of **[Trade Secret Begins...]** [redacted] **[...Trade Secret Ends]** NSP is required to procure incremental renewable generation to meet the Data Center load. At the Data Center's expected load factor, **[Trade Secret Begins...]** [redacted] **[...Trade Secret Ends]** load translates into an annual energy usage of **[Trade Secret Begins...]** [redacted] **[...Trade Secret Ends]**

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

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

VIII. Need Assessment of the Project

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

A. The Company does not project an immediate capacity need. In the Company's Strategist base case load forecast, which does not consider the additional Google Data Center load, new capacity resources are not added to the system until 2027 when the model adds a 374 MW combustion turbine in addition to a combined cycle project. The Dakota Range III defers the need for the 374 MW CT until 2030 to 2031.[10]

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

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

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

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

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

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

[10] Attachment A, PU-18-430 NDPSC 1-011.
[11] NSP Response to NDPSC-02-006.

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%

* Table excludes system purchases

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%

* Table excludes system purchases

IX. Evaluation of the Company's Economic Analysis of the Project

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

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

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

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

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

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

A. Yes. Specifically, I reviewed the following:

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

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

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

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

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

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?

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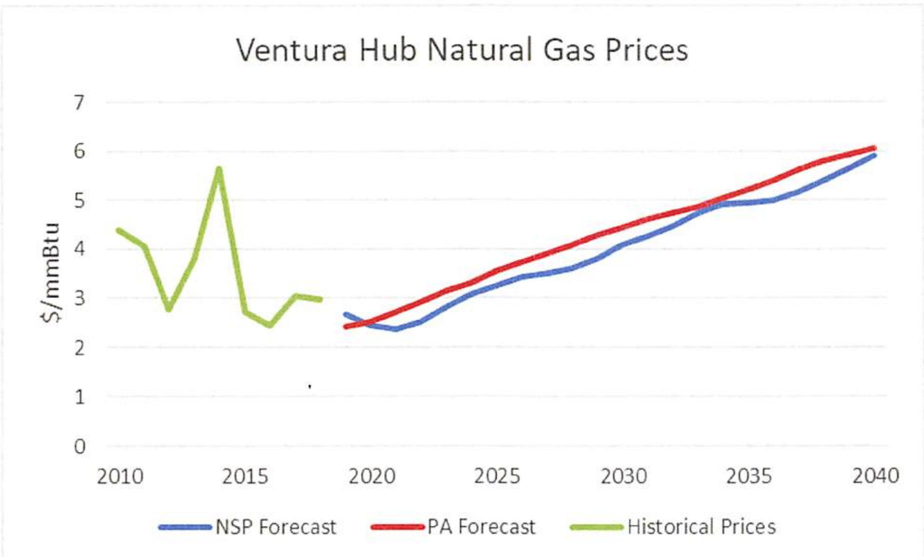
[12] MISO May 2018 Monthly Market Assessment Report, Market Evaluation and Design, July 12, 2018, p 16.

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

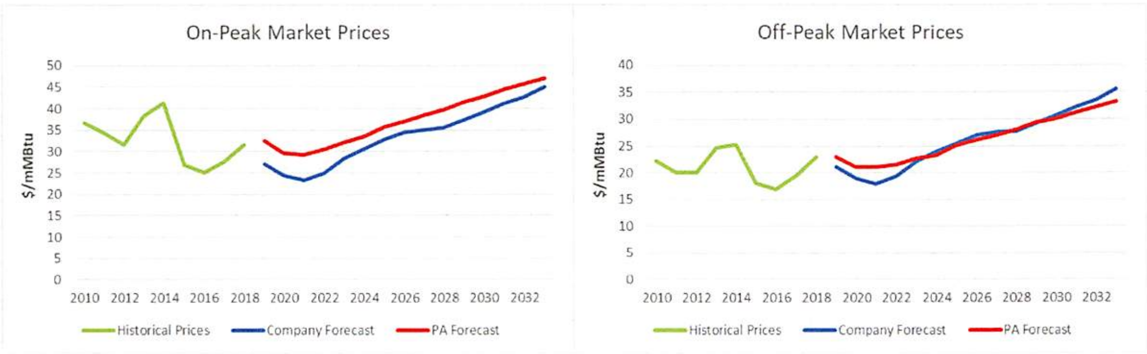
Figure 1. PA Natural Gas Price Forecast vs. NSP Forecast ($/MMBtu)



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

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

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



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

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

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

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

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

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

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

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

X. Evaluation of NSP's Supplemental Strategist Runs

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

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

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

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

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

A. Yes, the combined impact of adding the PPA and the data center load accelerated the need to add one 331 MW CT from 2030 to 2028.[13]

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

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

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

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

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[13] NSP Public Response to NDPSC 2-008.
[14] NSP confidential response to NDPSC-2-008.

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

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

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

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

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

[15] NSP response to NDPSC-1-014 (c)

XI. Independent Economic Analysis of the Project

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

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

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

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

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

A. Yes. The Company indicated expected curtailments of approximately **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]** Further, the Company indicated that the price of these curtailments was approximately **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]**. My analysis incorporated these curtailment costs.

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

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

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

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

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

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

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

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

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

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

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

XII. Assessment of the Projected Energy Cost Savings of the Project

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

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

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

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

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

Comparing my High Renewables scenario results of approximately $31 million of present value total system cost savings to my estimated base case present value of savings of approximately $48 million in savings, I find that it's reasonable to expect a significant reduction in estimated savings due to market prices being depressed due to the high penetration of lower cost renewables which were assumed in the scenario.

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

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

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

XIII. Allocation of Generation Demand Costs

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

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

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

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

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

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

XIV. Accounting for Fuel & Purchase Power Cost if ADP is Rejected

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

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

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

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

Q. What is your proposed alternative approach?

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

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

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

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

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

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

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

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

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

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

XV. Other Considerations

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

A. Yes. I have comments related to:

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

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

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

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

A. Yes, the PPA is a low-cost wind resource relative to the Company's current system. However, the relative savings compared to market purchases may be lower than forecasted based upon factoring in potential regional procurement policies that may be reflected in the IRP, such as Minnesota moving to 100% renewables by 2050 or Xcel's goal to have carbon emissions 80% below its 2005 level by 2030.[16]

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

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

Q. What are your concerns regarding the RECs?

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[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.

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

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

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

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

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

Q. Does this conclude your testimony?

A. Yes.