EXHIBIT 12

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TESTIMONY

CHARLES E. JANECEK

STATE OF NORTH DAKOTA

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY — CASE NO. PU-20-425

ADVANCED PRUDENCE – FOUR REPOWERED WIND PROJECTS

NORTHERN STATES POWER COMPANY — CASE NO. PU-21-093

ADVANCED PRUDENCE – 120 MW NORTHERN WIND FACILITY

46 PU-21-93 Filed 09/30/2021 Pages: 39
Exhibit 12 - Pre-filed Direct Testimony of Charles Janecek (Public)
Northern States Power Company

51 PU-20-425 Filed 09/30/2021 Pages: 39
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Northern States Power Company

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I. Introduction

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

A. My name is Charles E. Janecek and I work as a Principal Consultant for 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 25 years, specializing in electricity and utilities. I have worked on issues related to resource planning, rates, electricity markets, and the economics of financial transactions for utilities and wholesale generation owners. My academic background includes a BS in Geology from the University of Wisconsin-Madison.

Q. Have you conducted any resource planning studies for utilities?

A. Yes. While employed by Xcel Energy (Xcel) from 2006 through 2011 I conducted numerous resource planning studies using Xcel's Strategist and Planning and Risk models. These studies involved analyses related to portfolio optimization, the potential acquisition of individual resources, and the potential execution of bilateral purchases and sales.

Q. What is the purpose of this docket?

A. Northern States Power Company (NSP or Company) has requested an Advanced Determination of Prudency (ADP) for multiple wind generation-related expenditures. Specifically, the Company is requesting an ADP for expenditures related to: 1) repowering projects at four Company-owned wind generation facilities; and 2) the purchase of the 120 MW Northern Wind Facility (Northern Wind)[1] (collectively, the Wind Repower Portfolio). Based on the Company's pro forma analyses, it expects the repowering projects and Northern Wind to provide customers $138M and $30M in NSP system cost savings on a net Present Value of Revenue Requirements (PVRR) basis to customers over the projects' useful life, respectively. Based on the Company's portfolio optimization using its EnCompass modeling tool, it expects the Wind Repower Portfolio to provide up to $217M of system cost savings over the projects' useful life. I provide detailed descriptions of the ADP and the Wind Repower Portfolio in Section V of my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with my assessment and recommendations regarding the Company's request for ADPs of repowering the four wind facilities and purchasing the fifth. While the docket includes the consolidation of facilities into the Wind Repower Portfolio, I analyzed each facility separately and provide facility-specific recommendations.

II. Organization of the Testimony

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

A. Yes. I start with presenting my recommendations and findings and then provide details of my analysis. I discuss additional factors I considered and also propose conditions if the NDPSC approves any of the ADPs. My testimony is separated into eight additional sections:

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[1] The Company filed an Application for an ADP of the purchase of the Northern Wind Facility in NDPSC Case Number PU-21-093 that Case was subsequently consolidated with the Company's Application for an ADP of four wind repowering projects, which is Case Number PU-20-425.

- A summary of my recommendations (Section III);
- A summary of my findings (Section IV);
- An evaluation of the ADP for each of the wind facilities (Section V);
- Review of NSP's revenue requirement modeling (Section VI);
- Review of NSP's EnCompass modeling (Section VII);
- An evaluation of the Company's economic analysis of the Project (Section VIII); and
- My independent economic analysis of the Project (Section IX).

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring two exhibits:

- Exhibit CEJ-1: Charles Janecek CV
- Exhibit CEJ-2: PA Projected System Cost Savings

III. Summary of Recommendations

Q. Do you recommend the Commission approve the Company's Application for an ADP to repower and integrate each of the facilities in the Wind Repower Portfolio?

A. I conclude NSP was reasonable to assume that two of the five facilities in the Wind Repower Portfolio will provide benefits for ND ratepayers; however, I believe the Commission should consider approval or disapproval of ADPs associated with each individual facility rather than for the Wind Repower Portfolio as a whole.

I have two primary concerns:

- The Wind Repower Portfolio is not needed to serve the Company's retail load and is not needed for system energy or capacity; and

- Four of the five projects are projected to receive lower MISO market revenues than their revenue requirements, resulting in net losses to ratepayers.

For reasons more thoroughly discussed below, I recommend the Commission approve ADPs for the Grand Meadows Wind and Nobles Wind repowering projects, but deny approval for the Border Winds and Pleasant Valley Wind repowering projects, and deny approval for the purchase of Northern Wind.

Q. If the Commission approves some or all of the wind projects what conditions or qualifications do you recommend?

A. As conditions to its approval of any ADP, I recommend the Commission:

- Limit total cost recovery to how NSP identified it in its Application; ND customers should not be responsible for absorbing any contract modifications without further Commission review; and
- Require NSP provide ND customers with the full realization of each facility's Production Tax Credits (PTC) per NSP's Application for the ADP.

IV. Summary of Findings

Q. Would you please provide a summary of the findings you believe the Commission should consider as it determines whether to approve NSP's Application 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 to be favorable to approving the Application:

- Repowering the existing Company-owned Grand Meadows Wind and Noble Winds projects will result in savings to North Dakota customers over both the current and repowered expected life of the wind projects.

While there are favorable facts, however, I also have the following concerns:

- Repowering the existing Company-owned Border Winds and Pleasant Valley Wind facilities will not result in savings to North Dakota customers over the current expected life of the facilities. The Company's expectation of savings is based upon the revenue requirements of the repowered facilities compared to its expectations of the replacement cost of wind.
- Northern Wind is currently two PPAs and the Company is proposing to purchase the project once it has been repowered by its current owner, ALLETE Clean Energy (ALLETE). Based upon the revenue requirements, the cost of owning Northern Wind will be higher than if the Company purchases the same amount of energy from the market.

V. Evaluation of the ADP Application and Project

Q. Would you please provide an overview of the Company's Application for the ADP?

A. The Company is requesting an ADP for: 1) Expenditures related to repowering projects at four Company-owned wind generation facilities; and 2) Expenditures related to the purchase of Northern Wind.

Q. Would you please provide an overview of the Wind Repower Portfolio?

A. The four proposed repowering projects involve the following Company-owned wind generation facilities: Border Winds, a 150 MW facility in Rolette County, North Dakota; Grand Meadows Wind, a 100.5 MW facility in Mower County, Minnesota; Nobles Wind, a 201 MW facility in Nobles County, Minnesota; and Pleasant Valley Wind, a 200 MW facility in Mower County, Minnesota. The Company is also proposing to purchase Northern Wind, currently two PPAs, after it is repowered and expanded by ALLETE. I have summarized the Company's proposal in the following table:

Project	Current Capacity (MW)	Location	Current Life	Extended Life
Borders Wind	150	Rolette County, ND	2040	2049
Pleasant Valley	200	Mower County, MN	2040	2049
Grand Meadows	100.5	Mower County, MN	2033	2053
Nobles Wind	201	Nobles County, MN	Nov 2035	2045
Northern Wind	120	Murray County, MN	Dec 2023	2047

Q. Would you please summarize your understanding of the Company's proposal to repower the Border Winds project?

A. For the Border Winds project, the Company proposes to repower the full capacity of the facility by **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** which will result in an increase in the annual production of the facility. The project will continue to use the existing interconnection; however, the Company proposes to increase the facility's maximum production output to **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** which is greater than the 150 MW output specified in the original Generator Interconnection Agreement (GIA). This "oversizing" of the plant will allow for offsets of electrical losses and unplanned turbine outages and in turn will allow the facility to realize more energy production during periods when the facility is not producing the maximum MW output. The repowering is estimated to result in an average annual production of approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** percent efficiency gain over the current facility's estimated average annual gross energy production. Total capital costs for the Border Winds repowering are estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**, and the Company expects the project to qualify for **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** PTCs over its first ten years of repowered operation. The LCOE for the project is estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** lower than the current facility.

Q. Are there potential economic benefits associated with the Border Winds project?

A. NSP states repowering and extending the life of Border Winds will benefit local communities in North Dakota. In particular, the Company estimates 150 added jobs during repowering efforts and $1.4M in annual lease payments and tax revenues, which it notes is greater than North Dakota's proportional share of the overall NSP System.

Q. Would you please summarize your understanding of the Company's proposal to repower the Pleasant Valley Wind facility?

A. The proposed Pleasant Valley Wind repowering will include **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** which will result in the total production of the facility **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** As with the Border Winds project, the Company plans to continue operating under the existing GIA for Pleasant Valley Wind, which will limit peak production periods to 200 MW output but will allow for more energy production in non-peak production periods. The repowering is estimated to result in average annual production of approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** percent efficiency gain over the current facility's estimated average annual gross energy production. Total capital costs for the Pleasant Valley repowering are estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** and the Company expects the project to qualify for **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** PTCs over its first ten years of repowered operation. The LCOE for the project is estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** lower than the current facility.

Q. Would you please summarize your understanding of the Company's proposal to repower the Grand Meadows Wind facility?

A. The proposed repowering would not increase the maximum production capacity of the facility, but would **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**, and increase the facility's efficiency and capacity factor, resulting in increased total annual energy production.

The Grand Meadows Wind repowering is estimated to result in an average annual production of approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** percent efficiency gain over the current facility's estimated average annual gross energy production. Total capital costs for the Grand Meadows Wind repowering are estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**, and the Company expects the project to qualify for **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** PTCs over its first ten years of repowered operation. The LCOE for the project is estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** lower than the current facility.

Q. Would you please summarize your understanding of the Company's proposal to repower the Nobles Wind project?

A. Similar to the Grand Meadows project, the Nobles Wind repowering will not increase the production capacity, but will repower the full capacity of the facility, **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**. The project is estimated to result in an average annual production of approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** percent efficiency gain over the current facility's estimated average annual gross energy production. Total capital costs for the Nobles Wind repowering are estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]**, and the Company expects the project to qualify for **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** percent PTCs over its first ten years of repowered operation. The LCOE for the project is estimated to be **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** lower than the current facility. The Company also estimates that it may be possible for the Nobles Wind repowering to qualify for **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** percent PTCs, and if it is able to do so customers would realize additional benefits.

Q. Would you please summarize your understanding of the Company's proposal regarding early termination of the PPAs and purchasing Northern Wind?

A. The Company has requested an ADP for the acquisition of Northern Wind. The Company currently purchases the total output of two ALLETE-owned wind projects, Chanarambie and Viking (totaling100 MW), via PPAs that began in 2003 and are scheduled to terminate in 2023. NSP has reached a Purchase and Sale Agreement (PSA) with ALLETE for a complete replacement and expansion of the two facilities from 100 MW total output to 120 MW, resulting in the project which will be known as Northern Wind. Under the terms of the PSA, ALLETE will complete the replacement and expansion, and NSP will: 1) buyout the remaining two years of the current PPAs for the Chanarambie and Viking projects, and 2) purchase the entire repowered and expanded Northern Wind facility.

Specifically, the Company proposes to buyout the existing PPA and purchase the entire repowered and expanded Northern Wind facility for $210 million. The agreement includes **[TRADE SECRET BEGINS** [redacted] **TRADE SECRET ENDS]** for the 100 MW of repowering and **[TRADE SECRET BEGINS** [redacted] **TRADE SECRET ENDS]** for the additional 20 MW. Additionally, the project is expected to qualify for **[TRADE SECRET BEGINS** [redacted] **TRADE SECRET ENDS]** percent PTCs. At this purchase price and PTC level, the estimated LCOE for the Northern Wind project is slightly less than **[TRADE SECRET BEGINS** [redacted] **TRADE SECRET ENDS]**.

Q. Is the Company proposing to modify PPAs with existing wind projects that are targeted for repowering?

A. The Company selected three smaller projects to be repowered and provide energy to the Company through long-term PPAs. Those projects are: Ewington Wind, a 20 MW project in Jackson County, Minnesota; West Ridge Wind, a 9.5 MW facility in Pipestone County, Minnesota; and McNeilus Wind, a 37.5 MW project in Dodge County, Minnesota. Subsequent to filing the ADP, however, the Company is currently not proceeding with the West Ridge and McNeilus projects.[2] Because Ewington is under 50 MW, the Company is not requesting an ADP for that project and it was not subject to my analysis; however, the Company included all three of the PPAs in the modeling of the Wind Repower Portfolio.

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[2] Order Approving Wind Facility Repowering Projects, Docket No. E-002M/M-20-620, January 22, 2021, p 4.

Q. Are all the repowering projects in the Wind Repower Portfolio all Company-owned?

A. No. The four repowering projects (Border Winds, Pleasant Valley Wind, Grand Meadows Wind, and Nobles Wind) are all currently owned by the Company, which will conduct the repowering activities for those projects. The fifth project included in this ADP, however, is the Northern Wind project, which is currently owned by ALLETE, who will repower the facility prior to its proposed purchase by the Company.

Q. What incremental energy and capacity does the Company project from the Wind Repower Portfolio, and what are the projected Commercial Operation Dates of the repowered projects?

A. The Company expects the following incremental energy and capacity from the projects:

[TRADE SECRET BEGINS

Facility	Estimated incremental annual energy (MWh)	Estimated incremental nameplate capacity (MW)*	Estimated Commercial Operation Date
Border Winds	[redacted]	[redacted]	[redacted]
Pleasant Valley	[redacted]	[redacted]	[redacted]
Grand Meadows	[redacted]	[redacted]	[redacted]
Nobles	[redacted]	[redacted]	[redacted]
Northern Wind	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	

* Incremental nameplate capacity is not the same as MISO accredited capacity.

TRADE SECRET ENDS]

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[3] Pending FERC approval

Q. Would you please provide an overview of your analysis of the ADP application?

A. My assessment of the ADP Applications addresses two fundamental questions:

- First, is the Wind Repower Portfolio needed to serve NSP's load?
- Second, will the Wind Repower Portfolio lower net energy and capacity costs for NSP's North Dakota customers?

Q. Does the Company need the Project to meet the energy requirements associated with NSP's retail load?

A. No. The Company's Upper Midwest Integrated Resource Plan Supplement[4] (Supplemental IRP or Supplement) identifies the need for small amounts of energy efficiency, demand response, and distributed solar through 2025. The Supplement's Preferred Plan includes 500 MW of solar being added annually in 2025 and 2026, with the first wind resources added in 2032.[5] The Supplemental IRP's "Supplement North Dakota Scenario", prepared for North Dakota, includes no added wind units in this decade and no added utility scale solar until 2029.[6]

Q. Does the Company's modeling in EnCompass confirm the Wind Repower Portfolio is not needed to meet retail load?

A. Yes, using the EnCompass data provided by the Company,[7] I prepared a graph of the Company's forecast of total generation versus the forecast of retail sales in the scenario including the Wind Repower Portfolio. By 2025, after integrating all facilities in the Wind Repower Portfolio into the Company's system, the average ratio of retail sales to

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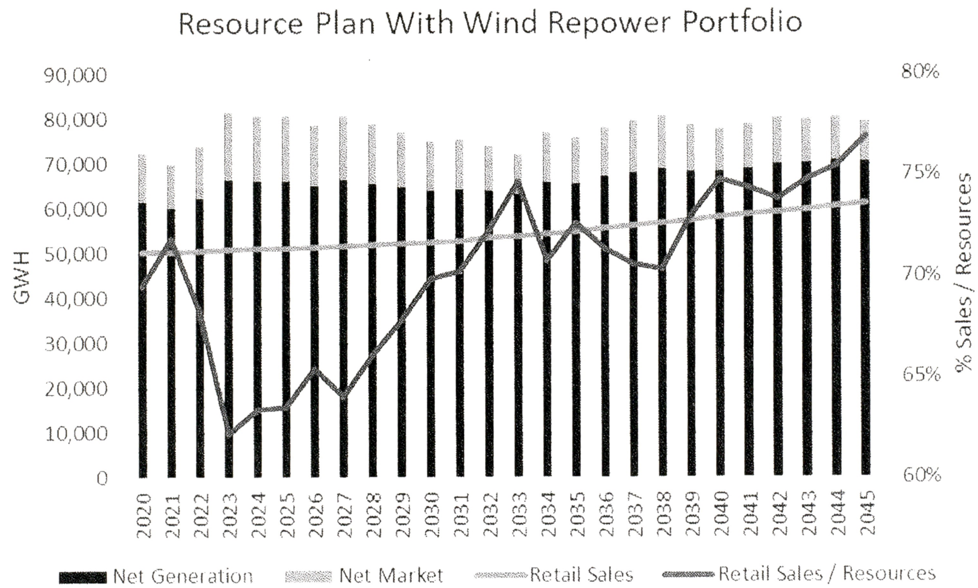
[4] See Case No. PU-19-220. XCEL ENERGY 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN SUPPLEMENT (June 30, 2020)

[5] Supplemental IRP Figure 3-2: Supplement Preferred Plan Resource Additions.

[6] Supplemental IRP Table 3-1.

[7] Trade Secret Attachment "EO - Wind RFP Base 091620 - Minus PPA FINAL.xlsb" provided in the response to PU-21-093 NDPSC-1-010.

resources is 70%. In other words, the Company is generating significantly more energy than needed to meet its retail load. My analysis is shown graphically below:



Q. Does the Company generate more energy from Company-owned resources and PPAs than needed to serve its retail load obligations?

A. Yes, based upon the Company's simulations in EnCompass, after the proposed repowerings and the Northern Wind purchase, from 2025-2045 the Company generates an average of 30% more energy than needed to meet retail load. After selling its excess generation into the MISO energy and capacity markets, the Company will potentially generate margins it could use to offset its power costs associated with serving retail load. Thus, the Company is essentially making a "bet" on the MISO markets by repowering and purchasing additional wind generation with the expectation that selling energy and capacity into MISO will be profitable.

Q. Does the Company need the Project to meet its capacity requirements/serve NSP's load?

A. No, based upon the Company's Supplemental IRP the Company will not need new capacity until 2026.[8]

Q. How much incremental capacity does NSP expect to secure as a result of repowering the four currently owned wind projects?

A. NSP will not gain any additional accredited capacity.

Q. How much incremental capacity does NSP expect to secure as a result of purchasing Northern Wind versus allowing the PPA to expire?

A. If the Company purchases Northern Wind it will acquire an additional 20 MW of MISO accredited capacity versus letting the PPA expire.[9]

Q. If the Commission approves the ADP application, what savings and costs do you expect for NSP's ND customers related to energy and capacity?

A. In total, my analysis concludes that through the end of the useful life of facilities in the Wind Repower Portfolio, the five projects are expected to lower average system energy costs based upon NSP's EnCompass modeling. However, as discussed in section VIII of my testimony, projected savings rely heavily on substantial savings post-2040 to offset increased near-term revenue requirements for three of the five projects. As discussed above, the Company is essentially placing a "bet" on the MISO markets, with the expected payoff being highly dependent on expected savings occurring approximately 20 years from now. It is this time element of the expected savings that causes my concerns about some of the requested ADPs.

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[8] Supplemental IRP Table IX-1.

[9] Based upon 16.7 percent ELCC per the testimony of Ms. Mandich, Schedule 2 Page 4 of 36.

Q. Based on your analysis, should the Commission grant ADPs for the projects?

A. My recommendation is that the Commission approve two of the five requests. In addition to evaluating whether the Wind Repower Portfolio would lower the Company's system average production cost and associated power costs for the ND customers, I recommend the Commission also consider the following:

- The Wind Repower Portfolio is not needed to serve the Company's retail load and the Company does not have an energy or capacity need for these resources; and
- While the Wind Repower Portfolio may result in future savings, near-term costs are actually higher than current costs.

Based on my analysis of the Wind Repower Portfolio's revenue requirements compared to its expected MISO market energy revenues, I recommend approval of the repowering of only the following two projects:

- **Grand Meadows Wind** – I project the Grand Meadows Wind repowering project will earn negative margins in the MISO markets; however, the project is expected to reduce the Company's system revenue requirements and is also expected to reduce the negative margins relative to the existing facility. As the project would both lower customer costs and potentially lower negative margins, I believe investing in the proposed repowering would be prudent.
- **Nobles Wind** – Similar to Grand Meadows Wind, I project the Nobles Wind repowering project would not only reduce revenue requirements but also potentially reduce the project's currently expected negative margins, and as such I believe investing in the proposed repowering would be prudent.

Conversely, based on my analysis, I recommend the Commission deny the ADP requests for the following three projects.

- **Border Winds** – While the proposed repowering could potentially increase the project's expected positive margins in the MISO markets between 2041-2049, the project's 2024-2040 PVRR are expected to increase by over $4 million. As such, the proposed project would increase customer costs over 2024-2040 in the hopes of realizing increased positive margins in the MISO markets from 2041-2049. Because the Company does not currently need the incremental capacity or energy associated with Border Winds, I do not believe investing in the repowering would be prudent.

- **Pleasant Valley Wind** –I project the proposed Pleasant Valley Wind repowering could potentially increase the project's expected negative margins in the MISO markets between 2041-2049; however, Pleasant Valley's 2024-2040 PVRR are expected to increase by nearly $8 million. Again, the Company is proposing to increase customer costs for this project between 2024-2040 under the expectation that it will realize positive margins beginning in 2041. Because the Company does not currently need the incremental capacity or energy associated with Pleasant Valley, however, I do not believe investing in the proposed repowering investment would be prudent.

- **Northern Wind** – I project the Northern Wind project would currently earn a very slight positive margin in the MISO markets in 2022-2023. However, the proposed purchase of the project would increase 2022-2023 PVRR by approximately $2.4M while incurring negative margins of present value $2.4M. Given that the current PPAs for the Northern Wind assets are set to expire in 2023 and the Company does not currently need the incremental capacity or energy associated with Northern Wind, I do not believe investing in the proposed acquisition would be prudent.

VI. Review of NSP's Revenue Requirements Modeling

Q. **Did the Company evaluate each wind project based upon the associated revenue requirements?**

A. Yes, the Company provided individual spreadsheet models for each wind project. The spreadsheet models evaluated the revenue requirements of the given proposed repowering/purchase ("proposed" projects) versus continuing to own the project without repowering or letting the PPAs expire for Northern Wind ("as is" case). The Company used its forecast of the market cost of replacement wind in the "as is" case so total energy provided is the same in the "as is" and "proposed" cases.

Q. **Why did you evaluate these models in addition to the Company's analysis of the Wind Repower Portfolio using EnCompass?**

A. The revenue requirement models provide a clearer picture of the benefits and costs of each project – particularly in analyzing the repowering of the four Company-owned resources. It not only removes any impact of the Company using carbon pricing in its portfolio optimization, but also avoids some of the conceptual issues with the EnCompass modeling (e.g., modeling the NSP portfolio as a closed system versus NSP being a full MISO market participant).

Q. **Would you please elaborate on what you mean by "a clearer picture"?**

A. Yes, the decision regarding whether to repower existing Company-owned wind projects has different nuances than whether to purchase or enter into a new PPA for a new resource. In the case of repowering the decision is whether to do nothing and continue with the current levels of wind production or invest in repowering and reap the benefits of the PTCs and small increases in energy production. The revenue requirement models more clearly demonstrate the cost to customers under both options. Among other things, NSP adds small amounts of market wind purchases during the life of the "as is" resource in these models so the "as is" and repowered resource provide the same level of energy. Under the revenue requirement analysis methodology, the revenues from selling the wind production to MISO is not critical to the analysis during the life of the existing wind resources.

Q. **Why are the revenues from selling into the market during the life of the existing projects not relevant in the revenue requirements models?**

A. The existing wind resources are sunk costs recoverable from customers. In the revenue requirement models, the revenue from delivering the output of the wind projects to the MISO market is the same in both the "as is" and "proposed" cases. Therefore, since the revenues are the same, the only impact to customers is the difference in the revenue requirement. However, this perspective becomes more complicated following the end-of-life of the wind project assuming the project is not repowered.

Q. **Why is the comparative revenue requirement analysis more complicated following the end-of-life of the existing wind project?**

A. For its existing projects "as is" analyses, NSP assumes market purchases of wind equivalent to the production of the repowered project to project end-effects. Consequently, the value of extending the life of the wind projects is largely influenced by the projected cost of replacement wind resources in the 2040s. Because the value of wind energy twenty years in the future is inevitably highly uncertain, I looked at ratepayer savings during the life of the existing project separately from potential savings after existing asset repowering.

Q. Do the revenue requirement models associate any value with retaining the transmission interconnection for the repowered projects?

A. No, and there is no need since the interconnection rights are not changed as a result of the repowering.

Q. **Are there also conceptual issues with the revenue requirement models?**

A. Yes, the modeled revenue requirements heavily rely on the Company's projected cost of replacement wind. As previously noted, the Company currently has excess energy and will be relying on selling significant amounts of energy into the MISO market to make the Wind Repower Portfolio profitable. I believe it would be more appropriate for the Company to use the lower of: 1) its expectation of the market cost of replacement wind or 2) its expectation of the market cost of electricity. In addition, the Company does not appear to look at the cost of wind if it repowers the assets at the end of their current lives.

VII. Review of NSP's EnCompass Modeling

Q. How did the Company evaluate the impacts of the four repowered projects and Northern Wind on system costs?

A. The Company conducted simulations to evaluate the projected impact of the repowered projects and Northern Wind on its system costs. The analysis was conducted in EnCompass, an hourly chronological production cost model. In projecting the economic dispatch of each NSP resource, EnCompass simulates the operation of the MISO System and estimates the total system costs impact of the facilities and includes a calculation of the system-level net present value of savings.

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

A. Yes. Specifically, I reviewed:

- The planning scenarios developed by the Company;
- The natural gas price assumptions used in the model;
- The four repowering projects and the purchased facility's modeled characteristics;

- Other NSP system inputs (including energy/demand forecast, wind integration costs, net generation, energy purchases and sales, wind capacity factor, generation profile and curtailment); and
- The reasonableness of the MISO wholesale electric market price assumptions.

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

A. Yes. The Company provided two sets of EnCompass models – one for the four repowered projects, and one for the Northern Wind purchase.

For the repowered projects, the Company developed a base case scenario using the Supplemental IRP, along with the approved repowering and purchase of the 99 MW Minnesota Mower Wind Project, a wind power PPA and a solar power PPA supporting the Company's Minnesota Renewable*Connect program expansion, and several other underlying modeling assumptions. The Company then developed an alternative case adding the Wind Repower Portfolio, that includes the four repowering projects described throughout my testimony as well as the three small, less than 50MW wind PPAs which are not included in the Company's ADP requests. In addition, the Company developed two alternative scenarios with low gas/low market prices and high gas/high market prices to estimate the savings by adding the Wind Repower Portfolio.

For the Northern Wind Encompass models, the Company used the above base case scenario but with the addition of the Wind Repower Portfolio, and then created an alternative case that included the addition of the Northern Wind purchase. As with the Wind Repower Portfolio EnCompass analysis, the Company also developed two alternative scenarios with low gas/low market prices and high gas/high market prices to estimate the savings by adding the Northern Wind purchase.

Q. How will the proposed projects earn revenues in the MISO markets?

A. Each 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. In the Company's EnCompass modeling, NSP assumes the surplus capacity is valued at the avoided cost of a generic brownfield H-Class combustion turbine.[10]

Q. Are the forecasted market prices critical to the evaluation of benefits of the proposed repowering projects and the Northern Wind purchase?

A. Yes, as previously discussed, the individual repowering projects and the Northern Wind purchase projected savings are a function of both the repowering and purchase costs and revenues based on the assumed market prices. NSP customers are likely to benefit from any generation added to its system, as long as the costs of those additions are lower than the assumed MISO market revenues. In its EnCompass expansion modeling, NSP constrained market sales to 25% of its load to restrict the model from potentially adding limitless low-cost wind resources.

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

A. Yes. When the marginal unit setting the market price is a natural gas-fired generation unit, there will be a strong relationship between gas and power prices. The MISO Market Monitor has reported a strong correlation between natural gas prices and wholesale market prices.[11] Notably, in 2020, coal units set the market clearing price 47% of the time whereas natural gas units set the clearing price 51% of the time.[12] With pending coal retirements, I expect natural gas will continue to set the market price in most hours.

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[10] Testimony of Ms. Mandich, Schedule 2 Page 20 of 36.

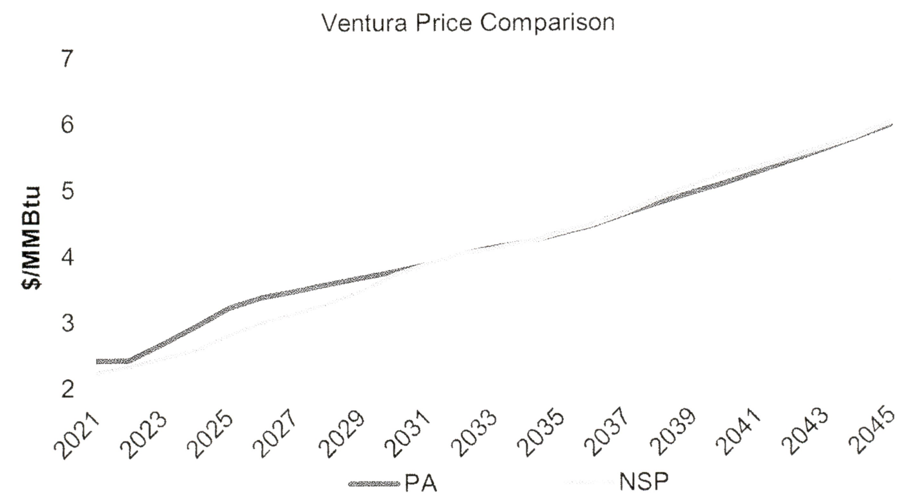
[11] 2020 State of the Market Report, Midwest ISO p 4.

[12] 2020 State of the Market Analytic Report, Midwest ISO, Table A1. https://cdn.misoenergy.org/2020%20State%20of%20the%20Market%20Analytical%20Appendix403116.pdf

Q. Is the Company's forecast of natural gas prices reasonable?

A. Yes, I compared the Company's delivered natural gas price forecast for the Ventura pricing hub in Minnesota with PA's forecast for the hub. The Company's forecast is somewhat lower than PA's forecast in the near term, which would tend to slightly decrease the associated market prices and projected benefits of the Wind Repower Portfolio.

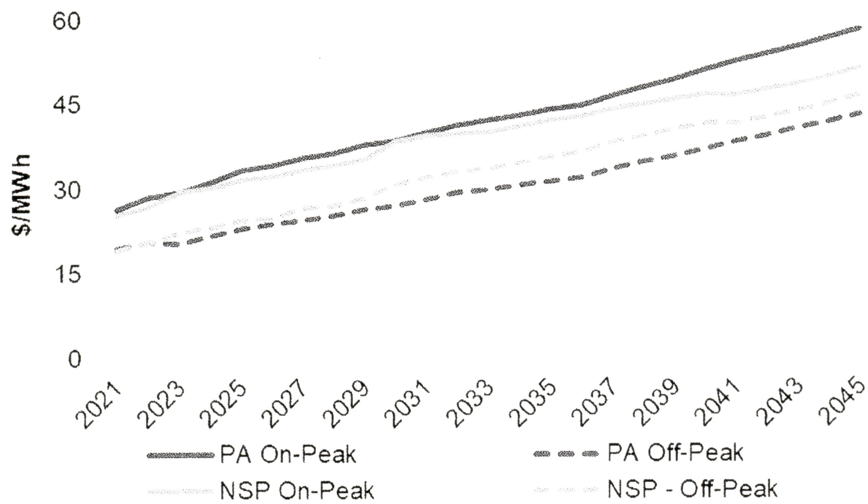
Figure 1. PA Natural Gas Price Forecast vs. NSP Forecast ($/MMBtu)



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

A. In MISO Zone 1, where all of the proposed projects are located, the Company's MISO off-peak power prices forecast are higher than the PA forecast and on-peak prices are similar to the PA forecast through 2029, but are generally lower than PA's forecast thereafter. See Figure 2. I find the Company's assumptions to be in the range of reasonableness; however, the PA forecast results in slightly higher savings for the individual projects.

Figure 2. MISO Zone 1 Forecast Prices ($/MWh)



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

A. The four repowering projects and the Northern Wind purchase will not materially change the Company's capacity mix. While two of the repowering projects will add production capacity to the facilities by utilizing the existing interconnection maximum output limits, they will not add any firm capacity to the Company's system. The Northern Wind purchase is expected to add 20 MW of nameplate capacity to the Company's system; however, the firm capacity of that additional 20 MW of nameplate capacity will add only approximately 3-5 MW of firm capacity over the existing PPA and would add approximately 20 MW of firm capacity compared to letting the PPA expire. In 2025, the Company's total firm capacity is projected to be 6,151 MW.

Q. Do the proposed projects impact the Company's energy mix from a resource diversity perspective?

A. No. I reviewed the results from the EnCompass modeling and have summarized the resource mix in the two tables below. In most years the mix of wind increases by only 1%.[13] Beyond 2035, the mix of wind changes as a result of different timing of wind additions between the Base Case and the case adding the repowering projects; however, both plans ultimately result in the same amount of wind generation. This result is not unexpected since the repowering does not add significant amounts of new wind production relative to the total resource mix. Purchasing the Northern Wind project versus allowing the current PPAs to expire has a small impact on changing the resource mix.

Table 1: GWH Resource Mix* without Wind Repower Portfolio

Resource Type	2022	2025	2030	2034	2040
Coal	10%	11%	0%	0%	0%
Nuclear	22%	21%	22%	14%	5%
Gas / Oil	20%	22%	23%	20%	13%
Hydro	4%	2%	1%	1%	1%
Wind / Solar	29%	28%	35%	45%	61%
Energy Efficiency	13%	15%	18%	20%	18%
Other	1%	1%	0%	0%	1%

* Table excludes system purchases; may not sum to 100% due to rounding

Table 2: GWH Resource Mix* with Wind Repower Portfolio

Resource Type	2022	2025	2030	2034	2040
Coal	10%	11%	0%	0%	0%
Nuclear	22%	21%	22%	14%	5%
Gas / Oil	20%	23%	22%	19%	14%
Hydro	4%	2%	1%	1%	1%
Wind / Solar	29%	30%	36%	46%	60%
Energy Efficiency	13%	14%	18%	20%	18%
Other	1%	1%	0%	0%	1%

* Table excludes system purchases; may not sum to 100% due to rounding

[13] NSP Response to PU-21-093 NDPSC-1-010 and PU-20-425 DOC 005 based upon the model tabs "Energy Mix All"

VIII.Economic Analysis based on NSP Modeling

Q. Did you review the Company's estimate that the repowering projects and Northern Wind purchase will have a $217M reduction in revenue requirements on a net present value basis?

A. Yes, I reviewed the estimate derived from the Company's EnCompass modeling (previously summarized above). Notably, the Company included its three smaller PPA projects as part of the Wind Repower Portfolio; however, because all three PPA projects are under 50 MW they are not subject to ADP approval. Further, as discussed previously, two of those PPA projects are not moving forward. Though they are smaller projects, NSP's decision to include them in the EnCompass modeling calls the estimated savings results from that modeling somewhat into question.

Q. Have you estimated the benefits to NSP's North Dakota customers?

A. To estimate the benefits to North Dakota, I considered the portion of savings that will directly impact North Dakota customers. North Dakota represents approximately 5.55% of the retail energy system sales.[14] At a high level, the Company's estimate of the present value of power cost savings to North Dakota customers is on the order of $12M.

Additionally, the Company's Application indicates the Borders Wind repowering project, which is located in North Dakota, can be expected to create around 150 temporary construction jobs over the duration of the repowering project. Further, over the project's expected 25 years of useful life (from the COD), the local area will benefit from extended average landowner payments of approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** per year, and average local property tax revenue of approximately **[TRADE SECRET DATA BEGINS** [redacted] **TRADE**

[14] NSP FCR filing for January 2021 Attachment H, Docker PU-21-012

SECRET DATA ENDS] per year. In total, these benefits amount to nearly $1.4 million per year.

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 EnCompass 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 EnCompass analysis.

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

A. I reviewed the Company's analysis and found the input assumptions and output results to be reasonable. However, I noted there is a range of reasonable results given the uncertainties surrounding fuel prices, generation additions, generation retirements, and load.

Q. Do you believe the EnCompass analysis and results are the most appropriate analysis and results for the Commission's consideration of the ADP requests?

A. No. While I recognize the EnCompass analyses provide a portfolio-level analysis of the projected benefits of the repowering projects and the Northern Wind purchase, I believe it is important to note the EnCompass modeling represents a long-term optimization of the Company's system resource additions. The EnCompass analysis assumes the repowering projects and the Northern Wind purchase are "locked in" to the Company's system prior to 2026, which is the first year the Company requires any additional capacity. In this manner, the EnCompass analysis does not appear to truly optimize the additions of the repowering projects and the Northern Wind purchase, but rather optimizes a new long-term portfolio built around those additions, and compares the cost of that new portfolio to the optimal plan identified in the Supplemental IRP filing.

Additionally, I think the Commission should consider the timing of the projected benefits of the repowering projects and the Northern Wind purchase. As my independent economic analysis of each project described below indicates, most of the potential benefits these projects may provide customers are projected to occur in the late 2030s and throughout the 2040s. While the EnCompass model uses reasonable inputs regarding fuel and market price forecasts, the reality is forecasts by their very nature are uncertain. The Company's revenue requirement projections, however, are much more certain because they are derived using the Company's cost estimates for the repowerings and Northern Wind purchase, all of which would occur in the next two years. In other words, the Company is attempting to justify incurring certain cost increases based on its expectation of surmountable benefits in approximately 15 to 25 years; however, these benefits are subject to significant uncertainty due to their reliance on uncertain price forecasts.

Q. Do resource acquisition decisions typically involve making long-term projections?

A. Yes, generation projects typically have useful lives of at least twenty years, so a utility has to make investment decisions based upon long-term expectations. However, for a vertically integrated electric utility the need to rely on long-term expectations is typically driven by the need to acquire a resource to meet retail load obligations. In this case there is not a need for additional energy or capacity.

IX. Independent Economic Analysis of the Project

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

A. Yes. While the Company's EnCompass analysis sought to evaluate the repowerings and the Northern Wind purchase as resources assumed to be already integrated into the NSP system, I took an alternate approach to evaluate the projects as MISO energy and capacity markets participants. Simply stated, my independent economic analysis approach assumes that the additional generation from the Wind Repower Portfolio in MISO Zone 1 would not significantly change generation dispatch in Zone 1, so MISO would dispatch the same NSP resources regardless of whether NSP repowers the four facilities and purchases Northern Wind.

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

A. Yes. I used the results from a PA Consulting forecast of MISO hourly prices in Zone 1. The forecast is an output from the Aurora XMP hourly chronological dispatch model. PA populates the model with assumptions regarding loads, generation, fuel costs, projections of generation additions and retirements, and transmission constraints. I used the forecast of hourly prices in conjunction with each project's hourly wind production profile to estimate the revenues the Company would receive from dispatching the Wind Repower Portfolio into the MISO market and from offering their capacity into the MISO Planning Resource Auction. I compared the estimated revenues with the Company's estimates of each project's revenue requirements.

I also evaluated the Company's calculated revenue requirements of the individual projects, focusing on the timing of any revenue requirements increases and decreases.

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

A. No, it does not.

Q. Does your economic analysis include any valuation of capacity value or Renewable Energy Certificate (REC) value?

A. No, it does not.

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

A. As noted, the Company based its savings estimates upon its EnCompass analysis of the difference in long-term portfolios that include or exclude the Wind Repower Portfolio, while my savings estimates are based upon the difference between the Wind Repower Portfolio revenue requirements and the revenues the projects can be expected to earn from the MISO energy markets.

Q. Could you please summarize your estimates of the projected energy cost savings based on your economic analysis?

A. Yes, Table 3 shows results from my analysis, which reflects the individual projects' economic analyses. I discounted the annual net margins using the same discount rate assumed by the Company (6.47%). My analysis indicates that though the Grand Meadows Wind and Nobles Wind facilities are projected to incur net margin losses when comparing revenue requirements to MISO market revenues, repowering the facilities would materially decrease those losses during the existing assets lives, and would also lower losses for Nobles Wind after the existing asset life.

My analysis indicates that for the Border Winds and Pleasant Valley Wind repowerings and for the Northern Wind purchase, the facilities' net margins would decrease during the existing assets lives while increasing after the assets lives. As discussed earlier in Section V of my testimony, the Company is proposing to invest in these three projects with the expectation that uncertain, long-term net margin increases will outweigh justify the near-term margin decreases.

Table 3. Independent Economic Analysis Results **[TRADE SECRET DATA BEGINS**

Wind Project	NPV[15] of Net Margins during existing asset's life ($M)			NPV of Net Margins after existing asset's life ($M)		
	As-Is	**Repowered**	**Change**	**As-Is**	**Repowered**	**Change**
Border Winds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Grand Meadows Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nobles Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pleasant Valley Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Northern Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
As-Is Total Net Margins ($M)						[redacted]
Repowered Total Net Margins ($M)						[redacted]
Repowering Net Margin Improvement ($M)						[redacted]

TRADE SECRET DATA ENDS]

Q. Could you please summarize your evaluation of the Company's calculated revenue requirements of the individual projects?

A. Yes, Table 4 shows the Company's calculated revenue requirements for each project, for the existing assets lives and for after the existing assets lives. With this data, a smaller number indicates a lower revenue requirement for the same level of energy production and hence lower cost to retail customers. Similar to the net margin analysis, my analysis indicates most of the expected revenue requirement savings occur beyond 2035. Because savings after the end of the existing asset life are driven by assumptions regarding the cost of purchasing future replacement power, there is uncertainty whether the expected savings will actually materialize.

Again similar to the net margin analysis, Grand Meadows Wind and Nobles Wind

[15] NPV for each asset is based upon discounting back to the existing asset's end of life.

provide material cost decreases in the near term as well as in the long term. However, the Border Winds, Pleasant Valley Wind, and Northern Wind all are projected to see increased revenue requirements in the near term relative to the existing assets, followed by decreased revenue requirements in the long term. As with the projected net margins, the Company is proposing to invest in these three projects with the expectation that uncertain, long-term cost decreases will outweigh and justify the near-term cost increases.

Table 4. Revenue Requirements Analysis Results **[TRADE SECRET DATA BEGINS**

Wind Project	Existing asset end of life	NPV of Revenue Requirements during existing asset's life ($M)		NPV of Revenue Requirements after existing asset's life	
		As-Is	Repowered	As-Is	Repowered
Border Winds	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Grand Meadows	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nobles	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pleasant Valley	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Northern Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TRADE SECRET DATA ENDS]

Notably, North Dakota customers will benefit from approximately 5% of the cost savings shown in Table 4.[16]

[16] The North Dakota energy allocation factor, which will vary by year. It was approximately 5.5% for the twelve months ending March 2021 (May, 2021 FCR Case No. PU-21-012).

Q. What are your conclusions regarding the Company's estimate of $217 million of system cost savings from the repowering projects?

A. While the estimate is in the range of reasonableness, the Company's projected savings are likely overestimated due to varying MISO market price assumptions (e.g., the difference between the Company's assumed cost of replacement wind power versus the Company's assumed cost of replacement market power). As shown in Table 3 above, my net margin analysis indicates an estimated system cost savings of $146.2 million.

Q. What amount of the Company's savings estimate would benefit ND customers?

A. Approximately $12M of the Company's savings estimates would benefit ND customers, in addition to the economic benefits described above.

Q. Does this conclude your testimony?

A. Yes.

CHARLES JANECEK

PRINCIPAL CONSULTANT

Mr. Janecek provides a unique blend of commercial consulting and utility planning experience to PA's clients with more than 25 years of experience in the electric power industry through previous positions with an investor-owned utility (IOU) and private consulting firms. At PA, Mr. Janecek is an integral member of PA's mergers and acquisition due diligence teams, having evaluated several electric and gas utilities, as well as portfolios of distributed generation and storage assets as well as utility-scale assets. As a resource planning expert, in recent years he has seen a significant increase in utility desires to evaluate both utility-scale and distributed storage opportunities, as well as demand response and energy efficiency programs, and has helped utilities and developers alike think about what markets are going to emerge for these products. Mr. Janecek is also an experienced Independent Evaluator, conducting oversight of major utility procurements of generation, storage, demand response, and energy efficiency programs. While a senior planner with an IOU, he was integral to the process of soliciting, evaluating, and procuring more than 2 GW of generating resource additions to the IOU system, including over 750 MW of wind generation and 80 MW of solar resources. When advising clients involved in wholesale markets and asset transactions, Mr. Janecek applies experience gained analyzing and facilitating transactions for more than 500 assets. He has modelled every area of the U.S. and Canada, along with many individual control areas within the markets, to support asset valuations, strategic planning initiatives, regulatory proceedings, and litigation proceedings.

PRIMARY EXPERTISE

- Integrated Resource Planning
- Independent Evaluator services
- Utility operations
- Power market economics and operations
- Valuation of physical and financial assets
- Gas, power, and coal market dynamics
- Litigation support and expert testimony drafting
- Contract negotiations

CLIENTS

- Xcel Energy
- Pacific Gas & Electric
- San Diego Gas and Electric
- PacifiCorp
- North Dakota Public Service Commission

QUALIFICATIONS

- 25-years experience with electric & gas utilities and electricity markets
- B.S. Geology

EXPERIENCE SUMMARY

- **Integrated Resource Planning** – Manage integrated resource planning assignments. The assignments have ranged from detailed scenario planning, fundamental and stochastic-based production cost modeling, dynamic capacity expansion optimization, management and regulatory presentations, and stakeholder engagement support.

- **Independent Evaluator Services** – Lead Independent Evaluator oversight of utility procurements, focusing on ensuring compliance with regulatory rules and regulations. Provide public service Commissioners and Staff advisory on risk mitigation methods for rate payer protection, independent verification of utility analyses, and engage with stakeholders on a variety of issues related to procurement.
- **Utility Operations** – Advise utilities on a wide range of utility operations. Lead solar and wind generation integration analyses, evaluating the impact these intermittent resources have on the operations and dispatch of the balance of system resources. Evaluation of the operations of pumped storage hydro resources for their ability to provide ancillary services to a given utility's system as well as the wider markets.
- **Power Market Economics and Operations.** Analyze and facilitate transactions for more than 500 assets. Model every area of the U.S. and Canada, along with many individual control areas within the markets, to support asset valuations, strategic planning initiatives, regulatory proceedings, and litigation proceedings.
- **Valuation of Physical and Financial Assets.** Conduct detailed dispatch projection analyses for assets located in regional transmission organizations and power markets, as well as bilateral, utility-based markets. Analyze hydroelectric, pumped storage, wind, biomass, geothermal, battery storage, hybrid solar-thermal, cogeneration, nuclear, coal, and natural gas as well as power and fuel contracts, financial hedges, and trading books.

EXPERIENCE

Provided independent evaluator and auditing services leading analyses to independently verify financial and production cost modeling conducted to support utility self-build projects as well as independent power producer bids. As independent auditor, Mr. Janecek led efforts to audit competitive procurement solicitations, including bidder communications monitoring, bid due diligence efforts, analysis review, and contract negotiations monitoring.

Supported two major western US IOUs in their competitive procurement process. PA provides independent evaluator services to both utilities, which requires the submittal of independent evaluators' reports to regulatory commissions certifying the fairness and equitable treatment of all bidders. These independent evaluation services require communications and contract negotiations monitoring, bids and analysis review, and regulatory reporting.

Provided the NDPSC with regulatory advisory, primarily prudency determination support evaluating multiple North Dakota utilities' applications for generation project prudency, as well as general rate case support.

Conducted a wide variety of due diligence tasks in support of a major western US IOU sell-side effort, including developing an integrated resource plan including projecting the utility's supply and demand needs over the next twenty years including the development of a detailed load forecast. Analyzed local natural gas, power, and transmission economics; the regional regulatory landscape; and state-level environmental policies as they pertain to the utility. Forecast capital and operational expenditures in the form of (1) new generation supply; (2) transmission and distribution operations and maintenance; and (3) large-scale business operations initiatives. Projected operations for the utility's owned and contracted supply resources, producing estimates for fuel costs and fixed and variable operations and maintenance costs; and developed reports and presentation material describing regulatory issues, market conditions, resource plan and capital and operating projections.

Led the development of a California publicly owned utility's integrated resource plan, quantified the uncertainties the utility faced as it considered the pending shutdown of the Intermountain Power Project. Guided the utility in developing portfolio scenarios for evaluation, then conducting stochastic production cost modeling to quantify the impacts that various resources will have on the utility and its ratepayers. Provided analytical support for the evaluation of a compressed air energy storage (CAES) facility as a potential source of ancillary services for the utility.

Assisted a offshore wind developer in projecting the operations, price suppression impacts, transmission congestion impacts, and ratepayer impacts of a proposed 1200 MW offshore wind facility developed off Maryland.

Led the development of a comprehensive integrated resource plan for a western Pacific island utility. A key component of the IRP was the development and production cost modeling of various resource portfolio scenarios. Collaborated with the client to utilize a structured framework for the development of those scenarios, providing a defensible and comprehensive approach toward defining the possible paths for the utility. Performed production cost modeling to quantify the scenarios including analysis of the system energy and demand requirements, conservation and energy efficiency opportunities, potential fuel infrastructure requirements related to liquefied natural gas and potentially liquid petroleum gas (propane), projected penetrations of distributed solar generation, potential new supply construction of thermal and renewable resources, and potential impacts to the utility's transmission and distribution systems and associated upgrade requirements.

Led several wind integration efforts, working with a multistate IOU's Energy Supply, Commercial Operations, and Resource Planning groups. Performed specialized modeling analyses to quantify the costs for procuring and dispatching intermittent wind resources. Assisted with the design a state-of-the-art wind generation forecasting system. Conducted a multi-year study to identify expected O&M costs related to extensive cycling of coal-fired plants due to wind generation. The study quantified the number of significant ramping events for each coal-fired plant on the system and then applied a cost per cycle to estimate annual cycling costs. These costs were compared to the estimated costs of curtailing the expected wind generation in place of ramping down the coal units.

CEJ–2

TRADE SECRET IN ITS ENTIRETY

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company **Case No. PU-**
20-425
Advance Prudence – Four Repowered Wind Projects
Application

Northern States Power Company **Case No. PU-21-093**
Advanced Prudence – 120 MW Northern Wind Facility
Application

VERIFICATION

STATE OF ____CO_________)

) ss.

COUNTY OF ____BOULDER___)

Charles Janecek, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matters under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

Charles Janecek

Subscribed and sworn to before me this 8th day of July, 2021.

RYAN JOLETTE
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20204040172
MY COMMISSION EXPIRES NOV 16, 2024

Notary Public

My Commission Expires: 11/16/2024