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Direct Testimony and Schedules
Bixuan Sun

Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in South Dakota

Docket No. EL25-____
Exhibit___(BS-1)

Resource Prudence

June 30, 2025

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bixuan Sun. I am Director of Resource Planning and Bidding for Xcel Energy Services Inc. (XES or the Service Company), the service company for Xcel Energy Inc. and its operating company subsidiaries.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since May 2020, in the area of resource planning modeling and analytics. In my current role, I am responsible for the development of resource plans and acquisitions for the five-state integrated Upper Midwest system. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. Prior to joining Xcel Energy, I was a post-doctoral researcher at the University of Minnesota. I received a Ph.D. in Applied Economics in 2018 from the University of Minnesota. My statement of qualifications is included as Exhibit___(BS-1), Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Direct Testimony is to support the following resource additions and retirement dates that are not currently reflected in South Dakota rates:

- Retirement of Allen S. King Generating Plant (King), a 598 megawatt

(MW) coal-fired single-unit plant, in 2028, and Sherburne County Generating Station Unit 3 (Sherco 3), a 927 MW coal-fired unit co-owned by the Company, in 2030;

- Extension of the remaining life of Monticello Nuclear Generating Plant (Monticello), a 671 MW nuclear-powered, boiling water reactor nuclear generating station, from 2040 to 2050;
- Extension of the remaining lives of Prairie Island Nuclear Generating Plant Units 1 and 2 (Prairie Island), two pressurized water reactors that combine for 1,076 MW nuclear-powered generation, from 2033 and 2034, respectively, to 2053 and 2054, respectively;
- Addition of Sherco Solar 1, 2, and 3 grid-scale photovoltaic (PV) projects with a collective nameplate capacity of 710 MW, in 2024, 2025, and 2026;
- Extension of the Manitoba Hydro power purchase agreement (PPA)for 200 MW of capacity and energy plus 350 MW for capacity only beginning in June 2025;
- Extension of the Cannon Falls PPA for three years until 2028 for short-term capacity of 357 MW.

Q. WHAT IS THE BURDEN THE COMPANY MUST MEET TO ESTABLISH INCLUSION OF COSTS OF ITS SELECTED RESOURCES IN BASE RATES?

A. My understanding is that South Dakota law only allows recovery in rates of costs that are "prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers" in South Dakota. Under general utility ratemaking principles, a resource addition or other investment is prudent if, considering all relevant circumstances, the utility's action was reasonable when it made the decision. This includes quantitative factors in the form of costs to customers as well as qualitative factors such as regulatory risk and reliability considerations.

Q. HOW DOES THE COMPANY SELECT RESOURCES TO BE ADDED, EXTENDED, OR RETIRED ON ITS SYSTEM?

A. The Company plans its five-state integrated system (the NSP System) on a holistic basis, with the support of forecasting tools to assess the economics of a given long-range resource plan, which may be done on a project-by-project or a portfolio basis. Additionally, for certain resources, we undertake reliability studies to help understand the impact of the retirement of those resources on the NSP System. Through these efforts, the Company seeks to develop and implement a portfolio of resources that will best support the Company's duty to provide efficient, safe, reliable and reasonably priced electricity for all of the customers served by the NSP System.

In recent years, as a result of ever evolving state and federal policies and laws, as well as Xcel Energy's corporate commitments, the Company has begun considering greenhouse gas emissions in its resource planning process to prioritize resources with lower carbon intensity. As a result, the Company has prioritized gas resources, rather than coal, and the use of renewable and storage resources where those resources would allow the Company to maintain reliable and affordable electric service. The Company also remains flexible to adopting new carbon capture technologies if necessary.

Q. HOW DOES PLANNING THE SYSTEM ON A HOLISTIC BASIS, ACROSS THE FIVE-STATE SYSTEM, BENEFIT SOUTH DAKOTA CUSTOMERS?

A. The integrated NSP System provides service on a multi-jurisdictional basis to our 1.6 million electric customers in South Dakota, Minnesota, and North Dakota, and through coordination with NSPM's sister company, Northern States Power Company-Wisconsin (NSPW), to customers in Wisconsin and Michigan. The NSP System has allowed the Company to develop and support various large-scale investments to serve customers. Because of the size of the integrated NSP System, the Company has been able to address significant load growth, supply uncertainty, and pricing volatility while maintaining low prices for its customers. Each resource in the NSP System – whether generation or transmission – is developed in consideration of the whole, balancing the need for diversity and hedges against supply and cost volatility.

This integrated approach allows for economies of scale system-wide, allows the states we serve to share in the costs of resources, and provides diversity and hedge benefits that might not otherwise have been available. On behalf of all of our customers, we take strategic advantage of the geographic, supply, and resource diversity that the five-state NSP System provides, with all states sharing in the costs and benefits of this system. While maintaining an integrated system at times requires necessary compromises between the various customer groups and jurisdictions we serve, the diversity of our System acts as a "hedge" for customers against fuel cost variability, concentrated geographic changes to the system, and supply problems. It also provides value to customers in the form of assurance that energy supply will be adequate and reliable regardless of market changes.

Q. HOW DOES THE COMPANY DEVELOP ITS RESOURCE PLANS?

A. The Company undertakes the resource planning process to determine how to meet its load in the most responsible manner. To develop our resource plans, we evaluate and compare a variety of scenarios against a reference case that reflects the preservation of the then-existing status quo. When reviewing a potential resource planning scenario against the reference case, we evaluate the scenario's ability to cost effectively and prudently allow us to meet our obligations to serve, as well as our obligation to comply with the legal and policy obligations applicable to the entire NSP System in a holistic way, without reliance on the Midcontinent Independent System Operator, Inc. (MISO) capacity auction.

The Company plans its system in cycles and presents formal resource plans to its Minnesota, North Dakota, and Michigan regulators in accordance with the resource planning statutes and regulations of those states. The Company files its 15-year resource plans with South Dakota on an informational basis per South Dakota Codified Laws 49-41B-3, as South Dakota does not have a formal resource planning approval process. A detailed timeline of the Company's recent resource planning history, with citations to the dockets where each plan has been filed with the Company's three utility regulatory commissions, is provided as Exhibit___(BS-1), Schedule 2.

Q. WHAT IS THE RESULT OF THE RESOURCE PLANNING PROCESS?

A. Through the resource planning process, the Company develops a plan for the continued operation or retirement of existing facilities, as well as the addition of new resources to address capacity shortfall resulting from retirements and new load growth on the system (the Expansion Plan). The Expansion Plan identifies generic resources, for which the Company must then procure specific projects.

Q. TO WHICH PARTICULAR RESOURCE PLANS DOES YOUR TESTIMONY REFER?

A. In my testimony, I refer primarily to our 2020 – 2034 resource planning cycle. The plan that resulted was the 2020-2034 Upper Midwest Integrated Resource Plan (IRP) of July 1, 2019, which the Company filed with this Commission as a part of its July 1, 2022 Biennial 10-Year Plan for Major Generation and Transmission Facilities in the State of South Dakota. My testimony also refers to a June 2020 supplement to that plan and to the 2024-2040 resource planning cycle, through which the Company presented an Upper Midwest IRP and a North Dakota Resource Plan.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO ITS BASELOAD GENERATION RESOURCES?

A. The Company is requesting two major adjustments for its baseload generation resources. First, the Company requests that the Commission approve the adjustment of the depreciable lives of King and Sherco 3 to match their planned retirement dates, as further described by Company witness Michele A. Kietzman. Second, the Company requests that the Commission approve the adjustment of the depreciable lives of Monticello and Prairie Island (collectively the Nuclear Facilities) to match their planned extended operational lives. The Company's analysis of these plans for its baseload generation resources indicates that when viewed under the totality of the circumstances, the Company's choices regarding its baseload resources are likely to result in savings for customers when compared to a status quo approach and are consistent with the Company's obligation to provide efficient, safe and reliable electric service.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO SHERCO SOLAR 1, 2, AND 3?

A. The Company requests that the Commission find that the addition of this resource was prudent at the time that the decision was made and allow the Company to include this resource in rate base.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO ITS POWER PURCHASE AGREEMENTS?

A. The Company requests that the Commission find the Manitoba Hydro PPA and Cannon Falls PPA were prudent when the Company agreed to them, and that the Commission allow recovery of the capacity costs of the contract in base rates and the energy costs through the fuel cost rider.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- Section II presents a summary of the types of economic analyses discussed throughout my testimony;
- Section III presents the Company's plan for its baseload generation, which includes retiring King and Sherco 3 in 2028 and 2030, respectively, and extending the depreciable lives of Monticello and Prairie Island to 2050 and 2053/54, respectively;
- Section IV presents the Company's decision to add 610 MW of solar generation at Sherco Station;
- Section V addresses the Company's decision to extend its existing PPAs;
- Section VI sets forth my conclusions and recommendations regarding the prudence of these various resource additions and retirements.

II. SUMMARY OF TYPES OF ECONOMIC ANALYSIS

Q. WHAT TYPES OF ECONOMIC ANALYSES ARE DISCUSSED IN YOUR TESTIMONY?

A. The Company has used two types of economic analysis to evaluate the impacts of resource additions and retirements, both of which are discussed at various points in my testimony: (1) an analysis using the Strategist resource planning model (Strategist); and (2) an analysis using the EnCompass resource planning model (EnCompass).

Q. WHAT IS THE STRATEGIST RESOURCE PLANNING MODEL?

A. Strategist is a modeling program that the Company used for many years to simulate the operation of the NSP System and estimate the total cost of energy and capacity over the planning period on a present value basis. Strategist can be used to test results under a range of input assumptions, also known as sensitivities. Strategist is a load duration model, in which the model plans capacity to a peak demand value each year and subsequently assesses whether the plan is energy sufficient to cover other periods of time. Strategist helped us evaluate proposed acquisitions in the broader context of the integrated NSP System by fully evaluating the impacts of an action relative to our entire resource portfolio. Until about four years ago, the Company used this tool for the majority of its resource planning efforts. Beginning in June of 2020, the Company began using the EnCompass modeling tool.

Q. WHAT IS THE ENCOMPASS MODELING TOOL?

A. Like Strategist, EnCompass is a capacity expansion tool that allows the Company to optimize resource expansion plans based on a set of assumptions. One of the primary differences in the models is that EnCompass evaluates resource needs and cost on a chronological hourly basis, which better accounts for hourly variations on our system than the Strategist model's load duration approach. This is an important feature that allows us to better account for the variable nature of renewable energy and duration-limited resources, such as energy storage or demand response. A full description of the EnCompass modeling tool is included as Exhibit___(BS-1), Schedule 3 to my testimony.

III. BASELOAD EVOLUTION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the evolution of the Company's baseload resources, and explain the resource planning that supported the Company's decisions to retire King and Sherco 3 in 2028 and 2030, respectively, in support of the Company's request that the Commission adjust the remaining lives of those facilities for depreciation purposes to match their currently scheduled retirement dates. I also discuss the prudence of extending the depreciable lives of the Nuclear Facilities.

Q. PLEASE DESCRIBE THE RESOURCES AT ISSUE IN THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I discuss the Company's coal and nuclear resource facilities, including the following:

- King is a single-unit coal-fired generating facility located on the St. Croix River in Oak Park Heights, Minnesota. The King plant was placed in service in 1968 and has a total nameplate capacity of 598 MW. The King plant underwent a significant rehabilitation from 2004 to 2007 as part of Xcel Energy's Metro Emissions Reduction Project.

- The Sherburne County Generating Station (Sherco Station) in Becker, Minnesota is the Company's largest power plant in the Midwest, with its three coal-fired units capable of providing a total of approximately 2,200 MW of electricity. Sherco 1 was placed in service in 1976 and has a production capacity of approximately 650 MW. The Company plans to retire Sherco 1 in 2026, consistent with its currently authorized depreciable end-of-life. Sherco 3 was placed in service in 1987 and has a production capacity of approximately 927 MW. Sherco 3 is 41 percent owned by the Southern Minnesota Municipal Power Agency (SMMPA), which is composed of municipal power companies operating on a cooperative basis. Sherco 2, which was previously retired in 2023, was placed in service in 1977 and prior to its retirement had a production capacity of approximately 650 MW. My testimony supports the decision to retire Sherco Unit 3 in 2030.
- Monticello is a core baseload generating unit in the Company's fleet, providing electricity 24-hours a day, seven days a week, for extended periods of time to meet steady demand for electric power. It is a single-unit, 671 MW nuclear-powered, boiling water reactor electric generating station located in Monticello, Minnesota. Since Monticello began operations in 1971, it has generated over 200 million MWh of electricity, and together with Prairie Island, represents nearly 30 percent of the total electricity our customers require today. The Company has received approval for a Subsequent License Renewal (SLR) from the Nuclear Regulatory Commission (NRC) to continue operating Monticello until

2050 and is seeking to extend the depreciable life of Monticello for an additional 10-year period from its currently set depreciable life of 2040.

- Prairie Island is a dual-unit, approximately 1,100 MW, nuclear powered, electric generating station using two pressurized water reactors, located in Red Wing, Minnesota. For over 50 years, Prairie Island has played a critical role in the fleet of generating resources Xcel Energy uses to serve South Dakota customers, generating over 400 million MWh of carbon-free electricity over its life. Prairie Island provides base load service; meaning it can operate at full capacity for 24 hours a day, seven days a week for extended periods of time to meet the ongoing, steady- or base-demand for electric power. Prairie Island and Monticello are the only generating stations in the Company's system that provide this level of consistent, reliable, carbon-free energy and capacity.

Q. AT A HIGH LEVEL, PLEASE EXPLAIN WHY THE COMPANY HAS REACHED THE DECISIONS IT HAS WITH RESPECT TO ITS BASELOAD RESOURCES.

A. In the 2019 resource planning cycle, the Company was presented with a unique opportunity to evaluate its entire delivery portfolio on a holistic basis, because the Company was anticipating a capacity shortfall relatively early in the planning period and because the coal and nuclear units would reach the end of their depreciable lives, and NRC licenses for the nuclear facilities, within the planning period. Importantly, the capacity shortfall would exist independent of any of the Company's decisions regarding its coal units, as I discuss in Section IV of my Direct Testimony. The Company entered the baseload resource evaluation process with an open mind and considered the economic benefits of each possible combination of resources moving forward, including no change.

Through that process the Company determined that the accelerated retirements of King and Sherco 3 and extension of the lives of the Nuclear Facilities are needed because they present a way forward for the Company, when looking at its entire resource portfolio, to accomplish three key objectives: (1) providing economical energy generation for the Company's customers; (2) ensuring the reliability of the system; and (3) protecting customers against a shifting and unpredictable policy landscape.

Q. IS THE COMPANY MAKING ANY REQUESTS WITH RESPECT TO SHERCO UNITS 1 AND 2 IN THIS RATE CASE?

A. No. In 2015, Docket No. EL14-058, the Commission approved depreciable lives of December 2022 for Sherco 1 and 2. Those lives were slightly adjusted in our prior rate case, Docket No. EL22-017, to 2026 and 2023 for Sherco 1 and 2, respectively. The Company's decision to retire those facilities was made as part of the system planning around 2016, and the Company has since planned new resource additions and existing resource retirements and extensions consistent with that plan. Furthermore, the Company has now retired Sherco 2.

Q. ARE THERE ADDITIONAL CONSIDERATIONS REGARDING SHERCO 1 AND 2?

A. Yes. The Company received the Commission's January 2024 letter, *see* Exhibit___(BS-1), Schedule 4, and I wish to provide some information in response. The Company understands the Commission's concerns that the retirement of the Company's coal units could add to uncertainty of resource adequacy in the Company's system and in the MISO area. The Company agrees with the Commission that the need for certainty and reliability on the system is of primary concern. The Company respectfully submits that it has prioritized reliability in its planning and that there are alternative, economic means to maintaining the reliability of the system while transitioning away from King and all three of the Sherco Units.

We are in the process of implementing a portfolio of resources identified through our Expansion Plan in the 2024-2040 Upper Midwest IRP that includes the resources I discuss in my testimony as well as resource additions that, while outside the historical test year and known and measurables of this case, will be added to the NSP System. These new additions include both renewable resources as well as 1,627 MW of firm, dispatchable resources and storage. Through these resource additions, the Company is planning for a future without its coal generation units that maintains the reliability of the entire NSP System. As I discuss in detail later in my testimony, the Company has completed an Energy Adequacy Analysis that stress-tested its Expansion Plan and demonstrated that the Company's resource planning decisions, including retirement of the coal units, are expected to result in the NSP System providing the necessary energy and capacity to meet all of our customers' needs. Exhibit___(BS-1), Schedule 5 is a copy of the Energy Adequacy Analysis.

A. Description of 2019 Resource Planning

Q. AT A HIGH LEVEL, PLEASE DESCRIBE HOW THE COMPANY EVALUATED ITS BASELOAD RESOURCES IN THE 2019 RESOURCE PLAN.

A. In 2019, faced with an aging coal fleet and nuclear resources nearing the end of their depreciable lives and NRC licensure, the Company reasonably determined to analyze whether those resources continued to be economic and otherwise reasonable resources on the NSP System. To evaluate this, the Company commissioned, reviewed, and undertook various economic and reliability analyses. The Company performed a Baseload Study that included the following components, addressing system reliability and economic analysis:

- A focused Strategist analysis, which examined the economic implications of various individual Unit and combined Unit retirements at different points in time;
- An EnCompass analysis to further examine the economic implications of various potential Unit retirements and extensions of life, considering both present value of revenue requirements (PVRR) and the present value of societal costs (PVSC);
- MISO Attachment Y-2 preliminary retirement studies, which assessed various single Unit and combined Unit retirement scenarios, including for King and Sherco 3, for thermal and voltage concerns;
- Xcel Energy Transmission Reliability Studies, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems; and
- Industry insights, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO Renewable Integration Impact Analysis (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region, as well as grid impacts at increasing levels of renewable penetration.

B. Economic Analyses

Q. YOU SAID THE COMPANY CONDUCTED AN ECONOMIC ANALYSIS OF THE RESOURCES ON ITS SYSTEM. HOW DID THE COMPANY ANALYZE ITS BASELOAD RESOURCES FROM AN ECONOMIC STANDPOINT?

A. In order to assess whether the King, Sherco 3, Monticello, and Prairie Island resources continued to be an economic way to meet the Company's customers' needs in an economic way, the Company developed 15 scenarios with varying combinations and timing of baseload unit retirements, including King, Sherco 3, Monticello, and Prairie Island. The scenarios did not include Sherco 1 and 2, because, consistent with the approved depreciable lives of those resources, the economic modeling assumed Sherco 1 and 2 would already be retired. The resources included in each scenario are identified in Table 1 below.

Table 1
Resource Planning Scenarios

Scenario	Resources
1 – Reference Case	Maintain the status quo from 2015 resource plan, including retiring King in 2037, Sherco 3 in 2040, and allowing the Monticello, Prairie Island 1 and Prairies Island 2 licenses to expire in 2030, 2033, and 2034, respectively.
2 – Early King	Reference Case, except retire King in 2028
3 – Early Sherco 3	Reference Case, except retire Sherco 3 in 2030
4 – Early Coal	Reference Case with respect to Monticello and Prairie Island, and retire King in 2028 and Sherco in 2030
5 – Early Monti	Reference Case, except retire Monticello in 2026
6 – Early PI	Reference Case, except Prairie Island is retired in 2025
7 – Early All Nuclear	Reference Case with respect to coal, retire Monticello in 2026 and Prairie Island in 2025
8 – Early Baseload	Retire King in 2028, Sherco 3 in 2030, Monticello in 2026, and Prairie Island in 2025
9 – Early Coal; Extend Monti	Retire King in 2028, retire Sherco 3 in 2030, continue operating Monticello through 2040, and allow the Prairie Island licenses to expire in 2033/2034.
10 – Early King; Extend Monti	Reference Case, except retire King in 2028 and extend the depreciable life of Monticello until 2040
11 – Early Coal; Extend PI	Retire King in 2028, retire Sherco 3 in 2030, Extend the depreciable life of Prairie Island Units until 2043/2044
12 – Early Coal; Extend all Nuclear	Retire King in 2028, retire Sherco 3 in 2030, extend Monticello until 2040 and Prairie Island until 2043/2044
13 – Extend Monti	Reference case, except extend Monticello until 2040
14 – Extend PI	Reference case, except extend Prairie Island until 2043/2044
15 – Extend All Nuclear	Reference case, except extend Monticello until 2040 and Prairie Island until 2043/2044

These scenarios also identified the size, type, and timing of new resources needed to continue meeting customers' needs and achieve our goal to reduce carbon emissions by 80 percent by 2030. We compared these scenarios to the reference case.

Q. PLEASE EXPLAIN WHAT THE COMPANY DID AFTER ANALYZING THESE SCENARIOS.

A. Through this analysis, the Company identified Scenario 9 as its Preferred Plan for its 2020-2034 resource planning cycle. In Scenario 9, King would be retired in 2028, Sherco 3 would be retired in 2030,[1] Monticello's depreciable life would be extended until 2040, and the Prairie Island units would operate through at least the end of their current licenses—with the potential to extend their lives based on the results of future analysis. The Scenario 9 retirement assumptions are shown in Table 2 below. The full assumptions used in the 2019 Strategist modeling are provided in Exhibit___(BS-1), Schedule 6.

Table 2
2019 Scenario 9 Retirement Assumptions*

Baseload Unit	Reference Scenario	2019 Scenario 9 / Preferred Plan Retirement Assumptions
King	2037	2028
Sherco Unit 3	2040	2030
Monticello	2030	2040
Prairie Island Unit 1	2033	2033
Prairie Island Unit 2	2034	2034

*These retirement dates reflect the assumptions and choices in the 2020-2034 Resource Plan prepared in 2019. We note that the Upper Midwest Preferred Plan, approved by the Minnesota Public Utilities Commission via its Order issued April 21, 2025 in Docket No. E002/RP-24-67, and the North Dakota Resource Plan currently pending before the North Dakota PSC in Docket No. PU-24-160, which cover the 2024-2040 period, continue to assume 2028 and 2030 for King and Sherco 3, respectively, but extend Monticello even further (to 2050) and also extend Prairie Island to 2053/54.

[1] In the subsequent modeling, discussed below, the Sherco Unit 3 was modeled with a 2034 retirement date to reflect its depreciation life.

Q. HOW DID THE COMPANY ANALYZE THE DIFFERENT SCENARIOS?

A. After identifying the 15 scenarios for analysis, we utilized the Strategist modeling tool to identify sets of resources necessary for the Company to continue to meet customer needs for each scenario, along with their resultant costs and emissions impacts. We also included the planning level mitigation cost estimates from the MISO Y-2 studies, as I noted earlier.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S ECONOMIC ANALYSIS?

A. Figures 1 and 2 below show the net present value delta of the modeled cost of each Scenario compared to the Reference Scenario, with negative values representing customer savings relative to the Reference Scenario and positive values representing increased costs. Figure 1 provides the Scenario deltas on a PVRR basis, which does not include any costs for emissions. Note that the PVRR deltas shown depict Net Present Value (NPV) for 2020-2045. Figure 2 provides the Scenarios on a PVSC basis, which included the costs for carbon dioxide and other emissions. In general, the scenarios that included coal retirements and nuclear extensions were the lowest-cost plans.

Figure 1
2019 Planning Scenarios – PVRR Deltas from Reference Case
($2019 millions)

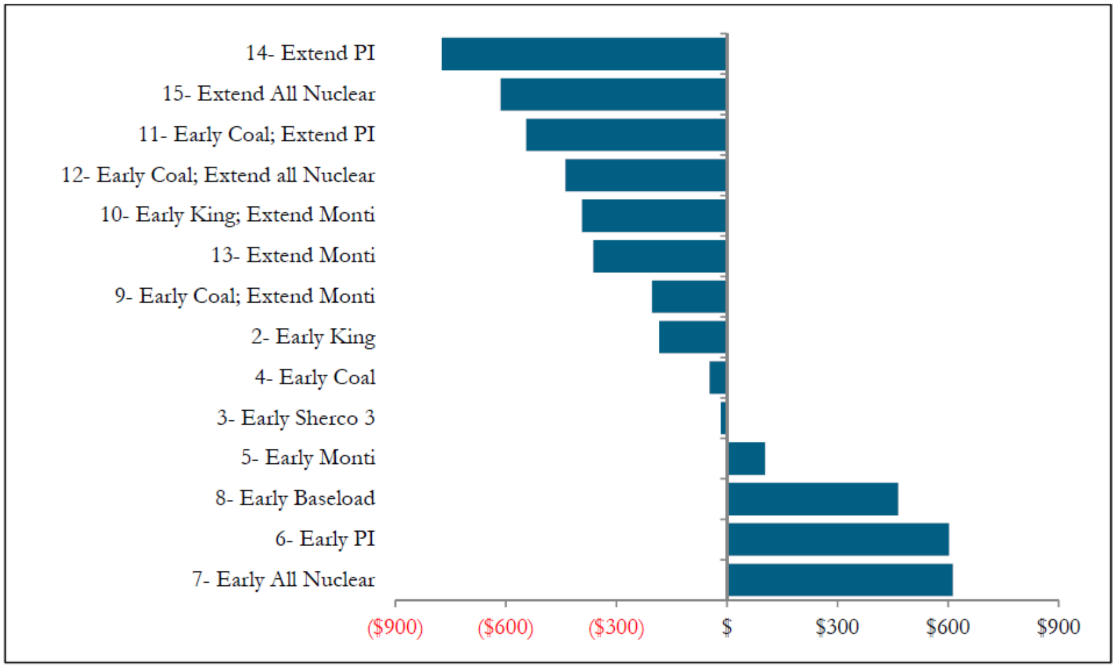
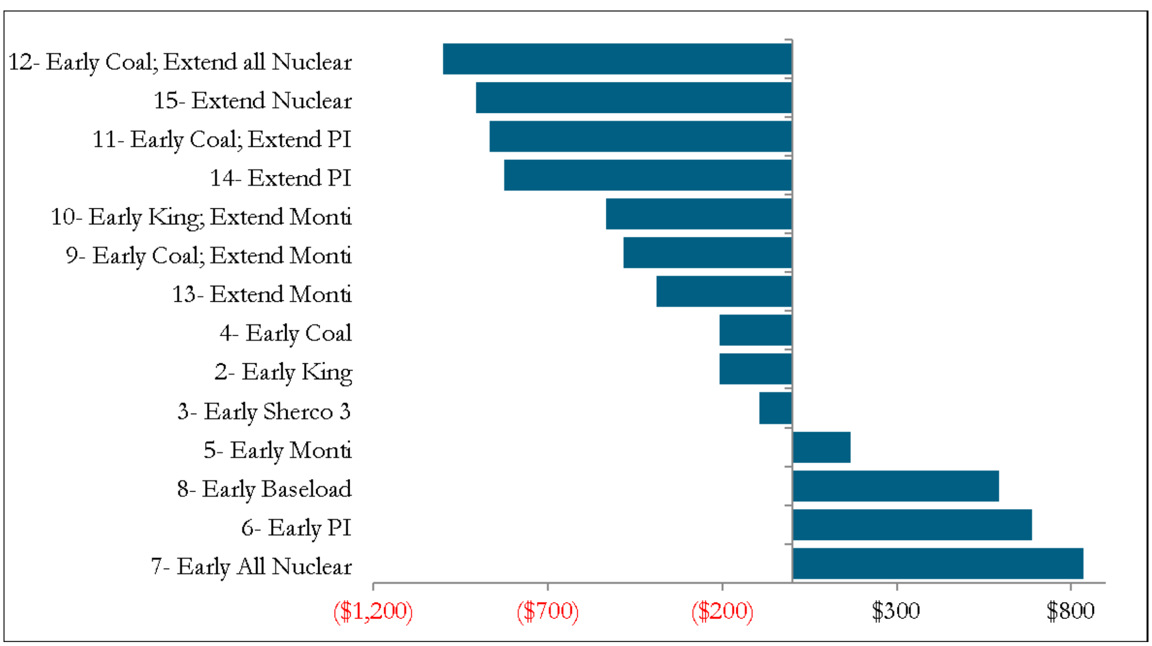


Figure 2
2019 Planning Scenarios — PVSC Deltas from Reference Case
($2019 millions)



Q. WHAT DOES FIGURE 1 ABOVE SHOW?

A. As Figure 1 shows, our 2019 Strategist modeling found that, on a PVRR basis, the retirement of coal units in Scenarios 2, 3, and 4 result in some economic savings, as compared to the Reference Scenario, both as standalone decisions and in combination, and regardless of whether carbon costs are considered. They further show that coal retirements combined with extension of the nuclear facilities in Scenarios 9, 10, 11, and 12 resulted in even more economic savings than only retiring the coal units. Scenarios 12, 14 and 15, which would extend the life of Prairie Island but not Monticello, would also result in significant savings. At the time, they were not selected, however, because deferring a decision on a potential Prairie Island license extension afforded us additional flexibility to address uncertainty around regulatory approvals for additional spent fuel storage, and currently, we are pursuing an extension of Prairie Island, consistent with Scenario 12. Figure 1 shows that coal shutdown combined with extension of all nuclear units (Scenario 12) was expected to result in the most savings compared to the reference case, but Scenario 9—which retired coal and extended the life of Monticello only—could achieve substantial savings in its own right while preserving the opportunity to extend Prairie Island in the future. It also shows that, without considering the societal costs of carbon emissions, retirement of King in 2028 and Sherco 3 in 2030 was expected to result in savings for customers when compared with the Reference Scenario.

Q. WHAT DOES FIGURE 2 ABOVE SHOW?

A. Figure 2 reflects the economic comparison of each Scenario, while factoring in the cost of emissions. The PVSC measured in Figure 2 is the cost of a particular resource plan when emission costs are added. The Company measures PVSC, because it is required to do so by law in Minnesota, using the Minnesota Public

Utilities Commission (MPUC)'s regulatory cost of carbon dioxide and externality values for criteria pollutants. Although South Dakota does not require consideration of the costs of emissions, to the extent the results are consistent with the PVRR-based analysis, which excludes carbon costs and all externality values over the modeling period, the PVSC measurement further supports the reasonableness of the Company's 2019 selection of Scenario 9 as a cost-effective way to provide affordable energy to South Dakota customers, while also providing a hedge to South Dakota customers against high compliance costs in the event a federal carbon policy is implemented.

Q. DID THE COMPANY SCREEN OUT ANY OF THE SCENARIOS SHOWN IN FIGURES 1 AND 2?

A. Yes. Because Prairie Island's license is not due to expire until the 2033-2034 timeframe, which was at the end of the planning period that was current at the time of the 2019 decision (2020-2034), and because the Company believed there was risk avoidance value in deferring a decision on Prairie Island extension, the Company deferred a decision on the Prairie Island license extension until a future resource planning process and eliminated it from further consideration in 2019. Therefore, cases that included a Prairie Island extension (Scenarios 11, 12, 14, and 15) were removed from consideration at that time. The Company subsequently decided as a part of its 2024 Resource Plans to capitalize on the predicted additional economic savings by proposing an extension of Prairie Island (to 2053 or 54). In 2019 when these decisions were being made, Scenario 9 preserved our opportunity to subsequently transition to other scenarios that could achieve more savings while also meeting our carbon reduction goals.

Q. WHAT WERE THE EXPECTED COST SAVINGS FOR SCENARIO 9?

A. The Strategist modeling indicated that Scenario 9, under which King would be retired in 2028, Sherco 3 retired in 2030, and Monticello extended to 2040, yielded customer savings of $204 million on a PVRR basis in the 2020-2045 period, relative to the reference case.

The Company also conducts sensitivities to test whether a particular scenario is robust across a broad range of future market conditions. Most of these sensitivities examine individual differences in isolation, so we can evaluate the impact of—for example—higher or lower market prices independent of any other changes. The sensitivity analysis demonstrated that Scenario 9 was expected to generate customer savings relative to the reference case in all sensitivities analyzed, with a range of $96 million to nearly $750 million.

Q. HAS THE COMPANY UPDATED ITS ANALYSES OF ITS BASELOAD GENERATION SINCE 2019?

A. Yes. The Company has continued to evaluate its decisions with respect to the baseload resources, considering current NSP System conditions, and has updated its analyses on three occasions. First, it completed a supplemental analysis in June 2020 (June 2020 Analysis). Second, it completed additional analysis in June 2021 (June 2021 Alternate Plan Analysis). Third, it analyzed extension of the depreciable lives of Monticello and Prairie Island as a part of its 2024 resource planning process.

Q. PLEASE DISCUSS THE JUNE 2020 ANALYSIS.

A. For our June 2020 Analysis, we updated several modeling inputs, accounting for the passage of time and further analysis requirements, and as noted above, we used the EnCompass modeling tool for the first time. The EnCompass model provides the additional capability of modeling our system on a chronological hourly basis. The more granular analytical capabilities of EnCompass provide a more precise view of our future energy and capacity needs in light of increasing levels of variable renewables and duration limited resources on our system. The full Strategist and EnCompass assumptions used for the June 2020 Analysis are provided in Exhibit___(BS-1), Schedule 7.

In this same time period, we conducted updated reliability analyses to verify that that the proposed baseload retirements and transition to intermittent renewable resources would not jeopardize reliability on the system.

Q. HOW DID USING ENCOMPASS CHANGE THE COMPANY'S ANALYTICAL PROCESS?

A. EnCompass better reflects grid operations and values a more complete range of resource attributes than Strategist modeling. Strategist utilizes load duration curves for capacity expansion simulations, primarily values capacity adequacy at an annual peak, and assesses a more "averaged" value for energy, whereas EnCompass examines the value and performance capabilities of various resources relative to customer needs across each hour in a sample set of days and weeks—or a full year. As a result, EnCompass expansion plans better account for resource contributions of variable renewables and duration limited resources—like battery energy storage—that may not be fully addressed in load duration modeling. As a result, the portfolios from our EnCompass modeling included a more diverse set of resources, balancing solar additions with more wind and firm peaking generation additions, than the Strategist expansion plans.

Q. WHAT WERE THE RESULTS OF THE JUNE 2020 ANALYSIS?

A. As shown in Figures 3 and 4 below, retirement of King in 2028 and Sherco 3 in 2030 under the "Early Coal" scenarios continue to perform well when combined with extension of the nuclear plants. Scenario 12, which would have the Company continue operating Monticello until 2040 and Prairie Island until 2053/54, continues to generate economic savings on a PVRR basis compared with the Reference Scenario. Additionally, when considering the cost of carbon, on a PVSC basis, Scenario 12 fairs even better, supporting the Company's conclusion that retirement of the coal facilities provides protection for the Company's customers against a shifting regulatory environment.

Figure 3
June 2020 Analysis – Baseload Scenario PVRR Deltas from Reference Case EnCompass ($2020 millions)

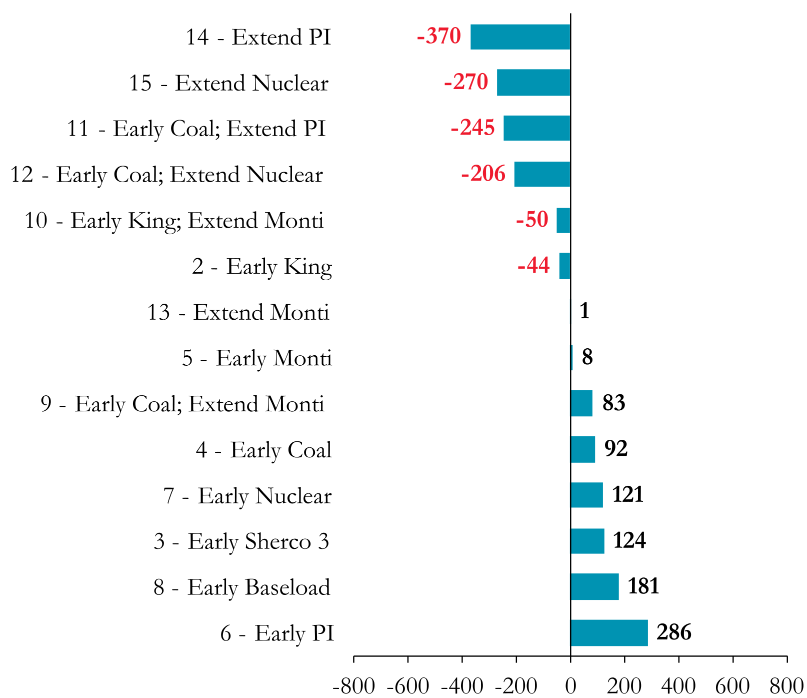
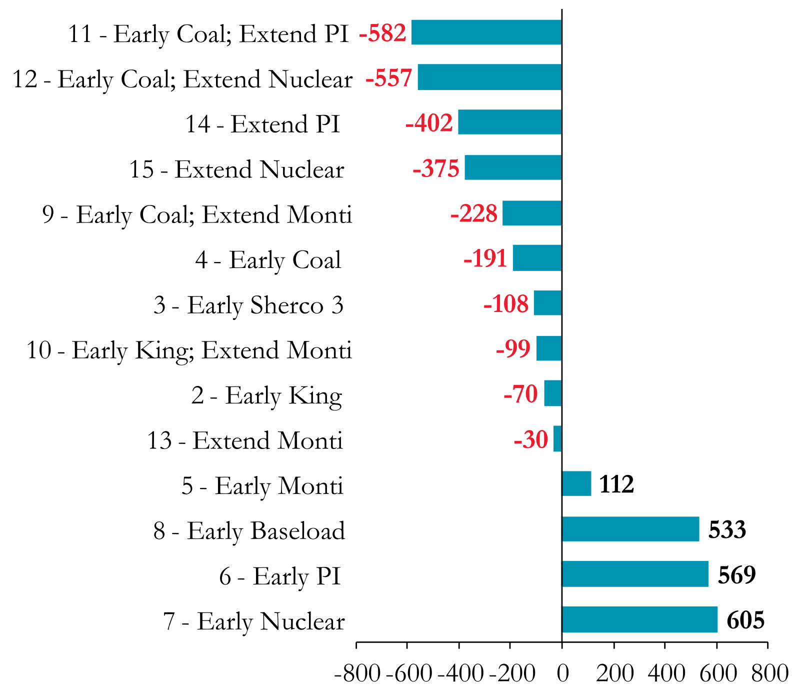


Figure 4
June 2020 Analysis – Baseload Scenario PVSC Deltas, Relative to Reference Case EnCompass ($2020 millions)



Q. Did the June 2020 Analysis impact your decisions with respect to its Coal and Nuclear resources?

A. At the time, the June 2020 Analysis confirmed our decision to move forward with Scenario 9 while we continued the work necessary to extend Prairie Island. On a PVRR basis, the EnCompass modeling showed that accelerated retirement of King and Sherco 3 when combined with extensions of both nuclear plants (Scenario 12) would yield financial savings. The Nuclear Facilities provide critical high-capacity-factor, carbon-free baseload generation that is important for maintaining overall reliability on the NSP System.

Q. Has the Company conducted any other analysis related to its baseload resources?

A. Yes. As part of our preparation of an "Alternate Plan" for our IRP in June 2021, the Company analyzed an updated Scenario 9 that removed the addition of a gas-fired combined cycle unit at the Sherco site and added transmission tie-lines to re-utilize the available interconnection rights for other resources at both Sherco and King. As with the earlier analysis, we conducted additional analysis on the reliability of the Alternate Plan. A summary of the Alternate Plan is provided in Table 3 below, and the full assumptions used in this modeling are provided in Exhibit___(BS-1), Schedule 8.

Table 3
Company Plan Performance Across Selected Key Planning Metrics

	Plan	Updated Scenario 9	Alternate Plan
Cost	PVSC delta ($ million, cost/(savings) relative to Reference Case)	($234)	($606)
Cost	PVRR delta ($ million, cost/(savings) relative to Reference Case)	$96	($46)
Environment	Carbon reduction by 2030 (percent, from 2005 levels)	80%	86%
Environment	Total carbon-free generation, 2034 (percent of total generation)	73%	82%
Risk and Reliability	Firm capacity-to-peak demand ratio	0.63	0.58
Risk and Reliability	Sensitivities - range of cost deltas relative to Reference Case	(1,090) – 124 *Median: (202)*	(2,163)-16 *Median: (544)*
Risk and Reliability	2034 Native capacity shortfall events	0	0
Risk and Reliability	2034 expected unserved energy (EUE)	0	0
Risk and Reliability	Loss of Load Hours (LOLH)	0	0
Risk and Reliability	2034 maximum 3-hour net load ramp under base assumptions (MW)	4,081	4,484

Q. WHAT DOES TABLE 3 ABOVE SHOW?

A. Table 3 provides a comparison of the Company's updated Scenario 9 and the Alternate Plan. Overall, both the Company's updated Scenario 9 and the Alternate Plan meet the goals of our core planning objectives–to maintain reliability and mitigate risk to the System at a reasonable cost, while also reducing greenhouse gas emissions. The updated Scenario 9 results in costs on a PVRR basis but achieves 80 percent carbon reduction and PVSC savings of $234 million relative to the reference case. The Alternate Plan achieves $46 million of savings on a PVRR basis and results in more savings on a PVSC basis ($606 million). Both plans maintain reliability and mitigate customer risk by including sufficient firm dispatchable generation to cover a substantial portion of customer load, particularly in the winter where – as we have seen again in recent years – significant customer needs may occur when variable renewables cannot be "switched on" like a dispatchable generator with physical fuel often can; therefore, being able to meet the majority of the Company's winter load with dispatchable resources on our system is a critically important risk and reliability consideration.

Q. DID THE COMPANY'S ANALYSIS AS A PART OF THE 2024-2040 RESOURCE PLANNING CYCLE PROVIDE DATA RELEVANT TO ITS DECISIONS ABOUT ITS BASELOAD RESOURCES?

A. Yes. For the 2024-2040 Resource Planning Cycle, the Company's reference scenario assumed the retirement of King and Sherco 3. The analysis also assumed extension of Monticello's depreciable life until 2040. The analyses identified two scenarios—an extend Prairie Island scenario (2024 Scenario 2) and an extend all nuclear scenario that would extend the depreciable lives of

Prairie Island to 2053/2054 and Monticello from 2040 to 2050 (2024 Scenario 3). Table 4 below reflects the cost impact of the three scenarios considered in the 2024-2040 Resource Planning cycle.

Table 4
Scenario PVSC/PVRR Deltas from Reference Case
($2024 millions)

PVSC Production Cost	Delta in NPV ($m) 2024-2040	NPV ($m) 2024-2040	Delta in NPV ($m) 2024-2047	NPV ($m) 2024-2047	Delta in NPV ($m) 2024-2050	NPV ($m) 2024-2050
Scenario 1 PVSC	$0	**$51,037**	$0	**$63,635**	$0	**$68,788**
Scenario 2 PVSC	($413)	**$50,624**	($437)	**$63,198**	($513)	**$68,275**
Scenario 3 PVSC	($785)	**$50,252**	($941)	**$62,695**	($1,025)	**$67,762**
PVRR Production Cost	**Delta in NPV ($m) 2024-2040**	**NPV ($m) 2024-2040**	**Delta in NPV ($m) 2024-2047**	**NPV ($m) 2024-2047**	**Delta in NPV ($m) 2024-2050**	**NPV ($m) 2024-2050**
Scenario 1 PVRR	$0	**$34,678**	$0	**$44,948**	$0	**$48,927**
Scenario 2 PVRR	($97)	**$34,581**	$291	**$45,239**	$391	**$49,317**
Scenario 3 PVRR	($464)	**$34,215**	$46	**$44,994**	$239	**$49,166**

Q. WHAT DOES TABLE 4 ABOVE SHOW?

A. Table 4 shows the NPV delta of modeled costs compared to the reference case under different time frames, with negative values representing customer savings.

Q. WHAT DOES THE COMPANY CONCLUDE FROM TABLE 4 ABOVE?

A. The 2024 Scenario 3, which includes the extension of Monticello's remaining life until 2050 and the extension of the remaining lives of the Prairie Island units to 2053/2054, is the lowest-cost plan through 2047 on a PVSC basis, and only increases cost slightly compared to the reference case on a PVRR basis through 2047. However, the costs shown after 2047 are driven by large resource additions in the model to replace the nuclear plants as they reach the end of their extended lives, which long-term costs for such replacement resources are less reliable than the costs expected over a shorter time horizon. Table 4 indicates that 2024 Scenario 3 yields the most attractive customer value relative to the reference case. Maintaining nuclear generation in our resource portfolio through 2050 provides fuel diversity and an ongoing source of baseload generation. From this analysis, the Company has concluded that extending the lives of the Nuclear Facilities would ensure reliability and affordability for customers.

C. Reliability Analyses of Baseload Resources

Q. YOU PREVIOUSLY REFERRED TO RELIABILITY ANALYSES THAT INFORMED THE COMPANY'S DECISIONS WITH RESPECT TO ITS BASELOAD RESOURCE PLANNING DECISIONS. AT A HIGH LEVEL, WHAT DO THE RELIABILITY ANALYSES ADDRESS?

A. The Company's economic analyses demonstrated that King and Sherco 3 would cease to be an economic way to meet customers' energy and capacity needs. But the Company could not plan to retire those facilities without also considering whether the removal of King and Sherco 3 from the NSP System would compromise the reliability of the System. The reliability analyses the Company undertook in 2019 were intended to address, broadly, the concept of grid stability—in other words, whether the retirement of King and Sherco 3 will cause voltage, thermal, or other stability concerns on the grid that would need to be mitigated in order for the plants to be able to retire. Grid stability is an engineering aspect of planning that our typical integrated resource planning economic modeling does not address, both because it can be highly locationally specific and because it measures grid operation on a timescale much more granular than our economic modeling. That said, we want our analysis to capture the economic costs of those engineering study results; for example, mitigation measures that MISO may require of us in our resource plan modeling, such as the MISO Y-2 study, to be sure we are appropriately accounting for the likely costs and benefits of those retirements as best we can, with the information we have at the time. For studies that are more qualitative and general to the broader MISO grid (such as the RIIA study), we also take information from those reports into account when evaluating potential future portfolios against each other.

Q. PLEASE DESCRIBE THE MISO Y-2 STUDY.

A. The current process for retirement of generation resources in the MISO footprint is generally governed by Attachment Y to the MISO Tariff. Preliminary retirement studies fall under Attachment Y-2, which is a confidential MISO analysis to determine if any adverse system stability impacts would occur as a result of potential generating resource retirement. The MISO Y-2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. The Company submitted seven Attachment Y-2 study requests with MISO, including retirement scenarios for King and Sherco 3. MISO performed its Y-2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues. We used the MISO planning level estimated mitigation costs from the Y-2 studies as an input to our resource planning modeling of the baseload unit retirements. These represent an appropriate proxy of potential costs to inform the economic aspect of our Baseload Study, although the final scope and cost of mitigations will be determined when the units retire.

Q. WHAT WERE THE RESULTS OF THE MISO Y-2 STUDY?

A. In general, the MISO Y-2 studies found that incremental retirements of baseload resources created manageable reliability impacts on the NSP System. The study analyzing the combined retirement of King and Sherco 3 found the need for an estimated $38.2 million in transmission upgrades to address several thermal overloads, which the study identified may occur upon the units retiring. As noted above and discussed further below, we incorporated the MISO planning level estimated costs from the Y-2 studies into our economic modeling of the baseload retirement scenarios for King and Sherco 3. We provide the MISO Y-2 studies as Exhibit___(BS-1), Schedules 9 and 10.

Q. DID THE COMPANY CONDUCT ANY ADDITIONAL RELIABILITY STUDIES?

A. Yes. The Company supplemented the MISO analysis with our own technical studies, examining traditional NERC reliability measures such as system stability and response. This provided a more robust look at potential impacts from baseload changes on the NSP system and the regional MISO grid than MISO's Y-2 studies. These technical studies simulated a number of varied conditions that consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. Note that these studies did not examine the retirement of King in 2028 and Sherco in 2030 specifically, but the overall trend toward retirement of large baseload plants.

Q. WHAT WERE THE RESULTS OF THE XCEL ENERGY RELIABILITY STUDIES?

A. In general, Xcel Energy's Transmission Reliability Studies found that—with currently available technologies—the system will need to retain a certain level of synchronous generation to ensure reliability, but that it is operable without traditional baseload generation like coal plants.

Q. DID THE COMPANY RELY ON ANY ADDITIONAL STUDIES OR RESOURCES IN EVALUATING THE RELIABILITY OF ITS SYSTEM IN 2019?

A. Yes, the Company relied on studies completed by MISO, the MISO RIAA, which was completed in 2017, and a 2018 Generator Retirement Scenario Special Reliability Assessment.

Q. PLEASE DESCRIBE THE MISO RIIA.

A. In 2017, MISO initiated a detailed exploration of assumptions regarding the way the electrical grid will work in the future in light of the "profound" change in the types of generating resources across its operating area and the implications of that shift for long-standing power system design and operational practices. The MISO RIIA study has three focus areas: (1) Resource Adequacy, or the ability to maintain the Planning Reserve Margin; (2) Energy Adequacy, or the ability to operate within generator limits such as ramp rates, min/max capacity, etc., transmission limits/ratings, and system limits such as energy balance and operating reserves; and (3) Operating Reliability, or the ability to operate the system within acceptable voltage and thermal limits, maintain stable frequency and voltage, and meet system performance requirements. In 2019, when we first determined that retirement of the coal units was likely appropriate, the MISO RIIA Study was ongoing, but one of the key conclusions was that renewable integration complexity increases sharply from 30 percent to 40 percent penetration.

Q. PLEASE DESCRIBE THE 2018 NERC STUDY.

A. NERC published its Generator Retirement Scenario Special Reliability Assessment on December 18, 2018, as part of its ongoing efforts to assess the potential implications of the changing generation resource mix on the reliability of the North American bulk energy system (BES). NERC's key conclusion was that the generator retirements that are occurring disproportionately affect large baseload and solid-fuel generation (coal and nuclear), and it underscored the importance of taking a measured approach to baseload unit retirement that includes thorough examination of potential reliability implications.

Q. WHAT ARE THE IMPLICATIONS OF THESE RELIABILITY ANALYSES ON THE DECISIONS THE COMPANY MADE REGARDING ITS BASELOAD RESOURCES?

A. In all, the reliability studies confirmed that, although there are stability implications of retiring King and Sherco 3, those concerns can be addressed with other, more economical investments. They also confirmed that some synchronous generation (or a like transmission solution) is broadly needed on the grid to maintain stability, which confirmed to the Company the importance of firm dispatchable generation as part of the NSP System's portfolio of resources moving forward. They also show that the transition away from large emitting baseload generation resources must be carefully managed to maintain resource adequacy and grid stability.

Q. DID THE COMPANY GIVE ADDITIONAL CONSIDERATION TO RELIABILITY IMPACTS BEYOND THESE STUDIES?

A. Yes. Reliability considerations are central to our resource planning process. In addition to the studies discussed above, we plan our system to be able to meet our capacity needs without reliance on the MISO capacity auction. As I discuss further below, when we evaluate potential future resource plans, we consider metrics such as the firm capacity to peak demand ratio, the number of shortfall events, the potential for unserved energy and loss of load hours, and the maximum 30-hour net load ramp. Through our resource planning process, we thoroughly considered the reliability impact of modifying our baseload generation portfolio to ensure that we can continue to provide reliable service to our customers.

Q. HAS THE COMPANY CONDUCTED ANY OF ITS OWN ANALYSIS OF THE RELIABILITY OF ITS SYSTEM?

A. Yes. As a part of our 2024 resource planning cycle, the Company stress-tested its preferred plan against historical hourly load and renewable production data using EnCompass modeling software. The EnCompass modeling reflects our actual system and market conditions and hourly production cost analysis. We used the model's full chronological modeling capabilities to run dispatch and cost analyses for the years 2027 to 2030, 2033, 2034, and 2040. Using each historical year from 2016 to 2022, we developed an 8,760-hour historical demand shape, along with monthly peak and energy forecasts, to calculate the future system level demand and shape to use in the EnCompass model. All existing wind and solar resources were dispatched based on their actual historical 8,760-hour production profiles or an 8,760-hour profile from a nearby facility. Generic facilities were given a random 8,760-hour profile. Using this historical data, we conducted a special study of four scenarios to ensure we would have sufficient capacity on our system to meet our customers' needs under varying weather conditions.

Q. WHAT RESOURCES DOES THE PLAN ANALYZED IN THE ENERGY ADEQUACY ANALYSIS INCLUDE?

A. The Expansion Plan studied in the Energy Adequacy Analysis includes

- The assumed retirement of King in 2028 and Sherco 3 in 2030;

- Extension of Monticello's depreciable life until 2050;
- Extension of the Prairie Island Units' depreciable lives until 2053/54;
- 3200 MW of wind additions through 2030;
- 710 MW of solar at Sherco Station and 400 MW of solar at King Station;
- 2,244 MW of firm dispatchable resources by 2030;
- 600 MW of battery energy storage systems (BESS) by 2030;
- Extension of the lives of the Company's three renewable Refuse Derived Fuel (RDF) waste to energy generating plants from 2027 until 2037 for two facilities and 2040 for the third.

On a long-term basis, the 2024 Expansion Plan also would have the Company add the following between 2031 and 2040:

- 1,100 MWs of incremental utility-scale solar;
- 5,200 MWs of incremental wind and repowering existing wind resources when economical;
- 1,500 MWs of incremental BESS;
- 1,347 MWs of incremental firm dispatchable resources;
- Developing additional regional transmission infrastructure;
- Growing our demand response (DR) portfolio to approximately 1,385 MW by 2040;
- Continuing plans to achieve average annual energy savings, through our energy efficiency programs, between 2031-2040.

Q. HAVE ALL OF THESE RESOURCES BEEN PRESENTED TO THIS COMMISSION?

A. No. We are in the process of implementing a portfolio of resources identified through our Expansion Plan in the 2024-2040 Upper Midwest Resource Plan.

The Expansion Plan identified generic resources to be added to the system. The Company is now in the process of procuring the actual projects. In addition, specific resources were approved as part of an approved Settlement Agreement in Minnesota. These new additions include 1777 MW of firm, dispatchable resources and storage, as well as renewable resources. As a result, many of the resources in the preferred plan that we analyzed in the Energy Adequacy Analysis are not before the Commission, and they likely will not be until they are placed into service.

Q. WHY IS IT REASONABLE FOR THE COMPANY TO LOOK AT THE RESULTS OF THE ENERGY ADEQUACY ANALYSIS AND DRAW CONCLUSIONS ABOUT THE DECISIONS REGARDING BASELOAD RESOURCES PRESENTED IN YOUR TESTIMONY?

A. The Energy Adequacy Analysis demonstrates that the Company can reliably operate the NSP System without its coal fleet, which would produce a more resilient and responsive system with an increased number of gas units dispatching into the market. It directly addresses the question the Commission raised in its January 2024 letter and shows that the NSP System without coal resources is sufficiently resilient to meet the needs of South Dakota customers.

Q. WHAT WERE THE RESULTS OF THE ENERGY ADEQUACY ANALYSIS?

A. This study reflected that the Company's preferred plan in 2024 provides a least-cost resource mix that will allow the Company to continue providing safe and reliable service.

D. Baseload Resource Decisions

Q. WHAT DID THE COMPANY LEARN ABOUT ITS BASELOAD RESOURCES THROUGH THE RELIABILITY AND ECONOMIC ANALYSES IT CONDUCTED?

A. In general, these analyses found that retiring King and Sherco 3 and extending the lives of the Nuclear Facilities: (1) is cost-effective from a PVRR basis; (2) maintains the reliability of the system by maintaining a robust share of firm and dispatchable generation relative to peak load across seasons; and (3) allows the Company to accomplish its goals and avoid risks associated with an ever-changing regulatory landscape.

Q. AS A RESULT OF THE ANALYSIS AND PLANNING EFFORTS YOU JUST DESCRIBED, WHAT IS THE COMPANY REQUESTING WITH RESPECT TO KING AND SHERCO 3 IN THIS RATE CASE?

A. The Company is asking the Commission to adjust the remaining lives of King and Sherco 3 for depreciation purposes to match the Company's planned retirement dates for these units in 2028 and 2030, respectively. The Company is moving forward to retire the facilities on these dates and seeks this Commission's approval of the depreciated life, because the retirement of coal has consistently been a low-cost option for the Company, it allows the Company to avoid capital intensive upgrades, and it is consistent with the Company's carbon reduction priorities.

Q. HAS THE COMPANY PREVIOUSLY RAISED THIS ISSUE WITH THIS COMMISSION?

A. Yes. The Company asked the Commission to find the 2028 and 2030 retirements of King and Sherco 3, respectively, prudent in its 2022 rate case. Ultimately the parties to that case reached a settlement that was approved by the Commission, in which the parties agreed that while the remaining lives of

King and Sherco 3 would not change at that time, Xcel Energy may request to alter the depreciation lives and rates for Sherco 3 and King in its next South Dakota rate case. The prior rate case settlement was expressly without prejudice with respect to the remaining lives of King and Sherco 3. Thus, the Company is renewing its request to alter the lives of King and Sherco 3, to 2028 and 2030 respectively, in this case.

Q. WHAT HAS THE COMPANY DECIDED WITH RESPECT TO ITS NUCLEAR FACILITIES?

A. The Company has decided to extend the life of Monticello an additional 10 years until 2050 and the lives of the two Prairie Island units to 2053 and 2054. The Company's nuclear facilities are valuable resources on the Company's system, as they provide valuable baseload that is consistent and reliable, while helping the Company achieve its carbon-reduction commitments and regulatory requirements. Maintaining this resource on the system provides a cost-effective way to maintain the stability and reliability of the system. The Nuclear Facilities provide carbon-free baseload generation, and in that respect, their continued operation is critical to reducing exposure to volatile prices of other types of fuels as well as future regulatory compliance costs associated with resources with significant air emissions. For these reasons, the Company's plan to extend the lives of the Nuclear Facilities is reasonable.

Q. HAS THE COMPANY PREVIOUSLY RAISED THIS ISSUE WITH THE COMMISSION?

A. No. The Company did raise the issue of extending Monticello's depreciable life from 2030 to 2040 in its prior rate case. On May 24, 2023, the Commission approved a settlement agreeing to extend the depreciation lives and rates for

Monticello to represent a useful life to the end of 2040. The Company has not previously raised an extension of the Prairie Island lives with the Commission.

Q. WILL THE COMPANY NEED TO OBTAIN ANY OTHER APPROVALS TO EXTEND THE LIVES OF ITS NUCLEAR FACILITIES?

A. Yes. Among other things, the Company needs to obtain a Subsequent License Renewal (SLR) to operate past the NRC license expirations of September 8, 2030, for Monticello, and August 9, 2033, and October 29, 2034, for Prairie Island. For Monticello, the Company filed its SLR application with the NRC on January 9, 2023. In December 2024, the NRC approved the SLR application, allowing Monticello plant operations through 2050. This SLR will be Monticello's second NRC license renewal, extending the Plant's life from 60 to 80 years, with a new expiration date of September 8, 2050.

For Prairie Island, the Company will need to file its SLR applications on August 9, 2028, for Prairie Island Unit 1, and October 29, 2029, for Prairie Island Unit 2; however, the Company plans to file its SLR application for both Units in late 2026. This SLR would be Prairie Island's second NRC license renewal and would extend the Plant's life from 60 years to 80 years, with a new expiration date of 2053/2054. The Company understands that the NRC's review process can typically take between 18 and 24 months.

Applications for SLRs are not uncommon in the industry. Indeed, most nuclear plants nationwide (including Monticello and Prairie Island) have renewed their operating license once already, more than half will need a second SLR by 2040, and five will need SLRs by 2030. A Feasibility Study commissioned by the Company determined that an SLR for Monticello should be financially prudent and technically viable. The Feasibility Study identified no fatal flaws, technical issues, or environmental concerns that would hold up the SLR process or prevent operation of the Plant during the 20-year SLR period. Further, the Company's previous experience with completion of the SLR process already for Monticello in 2006 and Prairie Island in 2014 helped it navigate many of the relicensing requirements for the second Monticello SLR and makes it optimistic about the outcome of its anticipated SLR application for Prairie Island.

Q. WOULD THE COMPANY NEED TO MAKE ADDITIONAL CAPITAL INVESTMENTS TO EXTEND MONTICELLO'S REMAINING LIFE PAST 2030 AND PRAIRIE ISLAND'S REMAINING LIFE PAST 2033/34?

A. Yes. The Company will need to make certain capital and operational investments at both Monticello and Prairie Island. Although the investments the Company has made over the last 15 years will significantly mitigate the scope of future investments needed to license the plants, nevertheless, investments will need to be made.

Q. PLEASE DESCRIBE THE INVESTMENTS NEEDED TO EXTEND THE REMAINING LIFE OF MONTICELLO.

A. At Monticello, the Company will need to expand the existing dry storage for spent fuel rods at the Independent Spent Fuel Storage Installation (ISFSI) at the Plant because the ISFSI will be full, with no space for additional storage, by 2030. In fact, even if the Plant did not obtain an NRC license renewal and began decommissioning in 2030, the existing ISFSI would still need to be expanded as part of decommissioning to accommodate all of the spent fuel on site.

Continuing to operate the Plant beyond 2030 will also require continued capital investments in future years as part of the Company's Aging Management Programs (AMPs). In addition to the 36 AMPs currently implemented at Monticello and five additional activities that would be credited as AMPs in the SLR, the Feasibility Study identified several AMPs that would need to be expanded or added for the second SLR. The Company has budgeted for initial implementation of these new and expanded AMPs, and ongoing O&M expenditures are required for these AMPs.

Making these investments will ensure that Monticello will continue to provide important reliability and resource diversity benefits as the NSP System continues to transition to more variable renewable generating resources in the future.

Q. PLEASE DESCRIBE THE INVESTMENTS NEEDED TO EXTEND PRAIRIE ISLAND'S REMAINING LIFE.

A. The only significant capital project currently identified as being necessary to run Prairie Island past 2033/34 will be an expansion of the ISFSI to provide sufficient dry storage for spent fuel rods.

Xcel Energy already implements a number of AMPs at the Prairie Island Plant that grew out of the initial license renewal process, as well as other existing programs that perform activities that will be credited as AMPs for the SLR. These AMPs manage aging effects for applicable passive and long-lived mechanical, electrical, and structural components to ensure component-intended functions are maintained. Intended functions are those functions that operators rely upon during and following design-basis events or other specific safety analyses. The Company expects that most of the existing AMPs will only require minor changes to achieve full compliance with NRC guidance. The Company may also implement new AMPs. Final determination will be through the SLR application development process.

Q. HAS THE COMPANY MADE ANY NOTABLE INVESTMENTS OR UPGRADES TO MONTICELLO IN RECENT HISTORY?

A. Yes. Over the past 15 years, the Company has undertaken several major capital projects at Monticello to increase its capacity and improve the safety and efficiency of the plant. With these investments, the Company was able to replace nearly all of the systems that support the reactor and power generation equipment at the Plant, resulting in a state-of-the-art facility that achieves industry-leading results in terms of safety, plant performance, and management of the Company's costs to achieve that performance. Monticello provides substantial customer benefits given the fixed costs associated with nuclear fuel, during a period when high inflation and severe weather events are causing other types of fuel prices to fluctuate and often rise. Given the Company has already made the investments needed to modernize Monticello, and the critical role Monticello plays in providing consistent baseload generation and reliability on the NSP system, it is prudent to extend Monticello's depreciable life.

Q. HAS THE COMPANY MADE ANY NOTABLE INVESTMENTS OR UPGRADES TO PRAIRIE ISLAND IN RECENT HISTORY?

A. Yes. Xcel Energy has done significant work at the Plant over the past license extension that has delivered results for our customers and that positions the Plant to be a critical component of our energy supply mix past 2033/34. That work has resulted in replacement of large assets and upgrade of control systems that support the reactor and power generation equipment. Some of the major projects undertaken on both units have included reactor and power generation equipment replacements and rebuilds, an upgrade of plant monitoring systems, and security upgrades. With this work, the Company has planned for the long-term future of Prairie Island and created a generation facility that can provide cost-effective power well past its current license expiration date. These efforts have improved the Plant's safety and efficiency and allow the Plant to be even more reliable during weather-related emergencies.

E. Summary

Q. PLEASE SUMMARIZE THE COMPANY'S PRIORITIES IN EVALUATING ITS BASELOAD GENERATION THROUGH THE 2019 RESOURCE PLAN AND SUBSEQUENT ANALYSES.

A. The Company evaluated its baseload resources in 2019 in response to a unique confluence of factors, including significant new capacity needs on the system and aging facilities. Its priorities in evaluating its baseload resources in 2019 and subsequently were the continued provision of safe, reliable, affordable electricity, consistent with the policy priorities of the jurisdictions where it operates. Because the Company does not plan for each individual resource in a vacuum, but instead evolves its system using a portfolio of resources to accomplish its goals, the Company considered the viability of all of its baseload resources and selected a scenario that was economically reasonable; insured the most cost effective, low economic risk dispatchable resources remained on the system for as long as possible; ensured flexibility with respect to future decisions; and allowed the Company to meet existing, and hedge against potential future, carbon reduction requirements.

Q. DID THE COMPANY'S DECISIONS TO RETIRE KING AND SHERCO 3 IN 2028 AND 2030, RESPECTIVELY, AND EXTEND THE DEPRECIABLE LIVES OF ITS NUCLEAR FACILITIES HELP PROGRESS THESE PRIORITIES?

A. Yes. The analysis supporting our initial decision to select Scenario 9—including retirement of both King and Sherco 3 both on an individual basis and as a part of the larger resource portfolio—showed that customers would see economic savings and benefit from this decision relative to alternate scenarios in which the units were kept online until their previous retirement dates. Subsequent analyses in 2020 and 2021 further supported this decision with updated inputs. This was especially true when, as a part of the larger portfolio, the retirement of coal was coupled with the extension of the Company's Nuclear Facilities. These results are expected to yield a reliable and economic system moving forward.

Q. HAS THE COMPANY BEGUN IMPLEMENTING ITS PLANNED CHANGES TO ITS BASELOAD GENERATION RESOURCES?

A. Yes. Because of the time these processes take, the Company has already had to begin implementing its plans. For King and Sherco 3, the Company has begun taking the necessary steps to initiate the shutdown process in compliance with applicable requirements, including notifying MISO of its intent to shut down the facilities. The Company has also begun the process of renewing its NRC license for Monticello, consistent with the terms of the Settlement in the 2022 rate case, which is also a prerequisite to further extending Monticello's life to 2050. The Company anticipates applying to renew its NRC license for Prairie Island in 2026.

IV. SHERCO SOLAR 1, 2, AND 3 ADDITIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I explain the basis for the Company's requests that the Commission find the additions of Sherco Solar 1, 2, and 3 prudent and that the Commission approve recovery of the costs and energy of these projects in base rates.

Q. PLEASE PROVIDE AN OVERVIEW OF THE SHERCO SOLAR 1, 2, AND 3 PROJECTS.

A. The Sherco Solar 1, 2, and 3 Projects are grid-scale photovoltaic (PV) projects with a collective nameplate capacity of 710 MW. They are located in the vicinity of the Company's coal-powered Sherco Station. By locating the Sherco Solar Projects near the retiring Sherco Units, the Company was able to take advantage of existing electrical and transportation infrastructure, existing transmission lines, and the Sherburn County Substation. Importantly, Sherco Solar 1, 2, and 3 will be able to reutilize the interconnection capacity made available by the December 31, 2023 retirement of Sherco Unit 2. Sherco Solar 1 came into commercial operation in October 2024, and Sherco Solar 2 and 3 are expected to achieve commercial operation in October 2025 and August 2026, respectively.

Q. HOW AND WHEN DID THE COMPANY DECIDE TO ADD SHERCO SOLAR 1, 2, AND 3 AT SHERCO STATION?

A. As early as 2010, the Company began anticipating that a large capacity deficit would appear on its system in the mid-2020s. The deficit is the result of a variety of changes on the system, including new load, expiration of PPAs, and retirements of a variety of generation resources, including but not limited to the coal units, as discussed in more detail below. The analysis in our 2019 IRP indicated that additions of solar could meet part of the need for resources. In response to this anticipated deficit, the Company conducted a competitive request for proposals (RFP) process to bring new solar resources onto its system in early 2021. Sherco Solar 1 and 2 were the projects selected out of that RFP process. The Company conducted another RFP for up to 300 MW of solar to replace the remaining transmission interconnection rights that will be available upon the retirement of Sherco Unit 2. The Company initially bid a 150 MW Sherco Solar 3 project. However, through the bidding process, a number of bids withdrew, failed to meet the evaluation criteria, or were otherwise found not to be in customers' interest because of the bid price offered. As a result of that process, the Company elected to build 250 MW of solar as a part of Sherco Solar 3. The RFP process, alongside economic modeling and qualitative risk considerations, has confirmed that building Company-owned solar at Sherco Station is the most prudent solution for timely meeting identified capacity needs.

Q. PLEASE DESCRIBE THE CAPACITY DEFICIT THE COMPANY FORECASTED ON ITS SYSTEM.

A. For nearly 15 years, the Company has been forecasting that a large capacity need would arise in the mid-2020s. The Company first identified this capacity need in our 2011–2025 Resource Plan. We continued to forecast similar capacity needs in subsequent resource plans, including in our 2016–2030 Resource Plan and the supplement thereto, our 2020–2034 IRP filed in 2019 and the June 2020 supplement thereto, and in our 2024-2040 IRP. The June 2020 Supplement to the 2020–2034 IRP, which was the most recent resource plan in place at the time the Company made the Sherco Solar decisions, forecasted a 92 MW net capacity deficit arising on the system in 2026 and growing to 1,016 MW by 2030. The 2024-2040 IRP forecasts that, even assuming the Sherco Solar projects will come online in 2025, there will still be a need for additional capacity starting in 2027 and growing over time, which further re-emphasizes the necessity of filling the need identified by the prior resource plans.

This capacity need identified in past resource plans is due to a variety of factors, including anticipated load growth, the then-pending expiration of several large PPAs (including but not limited to large hydroelectric contracts), and multiple retirements of existing Company-owned generation facilities. The reduction in energy resources the Company anticipated include at least the following:

- 2023: Blue Lake Units 1-4 (natural gas combustion turbines (CTs)) cease operation (153 MW);
- 2025: Manitoba Hydro contracts expire (850 MW);
- 2025: Cannon Falls contract (natural gas CTs) expires (357 MW);
- 2025: Wheaton 1-6 (diesel and natural gas CTs) to be retired (300 MW);
- 2026: Cottage Grove Combined Cycle Energy Center contract expires (262 MW); and
- 2027: Mankato Energy Center Combined Cycle (MEC I) contract expires (375 MW).

The combination of all of these expirations, growth of the system, and retirements, contributed to the need identified in the 2020–2034 IRP for new generation resources beginning in 2026.

Q. DOES THE PRUDENCE OF SHERCO SOLAR 1 AND 2 DEPEND UPON A FINDING THAT THE CLOSURES OF THE SHERCO UNITS, WHICH YOU HAVE DESCRIBED AS CONTRIBUTING FACTORS TO THE CAPACITY DEFICIT, WERE PRUDENT?

A. No. The Company plans its system on a portfolio basis, which means that it reviews both its capacity needs and its resource additions across the entire system, not on a resource-by-resource basis. While Sherco Solar 1, 2, and 3 are located at or near the Sherco Station and reuse infrastructure and interconnection rights previously used by Sherco Unit 2, the Sherco Unit retirements are only one variable creating the capacity deficit that Sherco Solar 1, 2, and 3 will contribute to filling. The inverse is also true—Sherco Solar 1, 2, and 3 are only part of the larger portfolio the Company has developed to meet its overall long-term capacity deficit. Moreover, the decision to retire the Sherco Units was made more than six years ago, and the Company has had to take steps to implement that decision and address the system requirements that they create. Because these projects require years to plan, permit, construct, and make operational, the Company had to timely respond to the capacity deficit on its system and begin putting new resources on the system. Sherco Solar 1, 2, and 3 are a part of a prudently adopted portfolio of resources that are allowing the Company to meet its capacity needs.

Q. WILL THE ADDITION OF THE SHERCO SOLAR PROJECTS SATISFY THE COMPANY'S CAPACITY NEED?

A. As discussed, to address the identified capacity need, the Company took a portfolio approach that included adding solar generation, as well as Company-owned firm dispatchable capacity, among other resources to meet near-term capacity needs. In addition to the Sherco Solar units, we have extended multiple PPAs, proposed the extension of Monticello and Prairie Island, and are proposing additions of firm dispatchable resources, including the repowering project at Wheaton and additions at Lyon County and Blue Lake, as well as renewable and storage additions. As a part of this portfolio approach, adding Company-owned solar at the site of the soon-to-be-retiring Sherco Units that could use the Company's existing interconnection rights was determined to be a cost-effective solution to reliably meet the identified need at the time the need was forecasted to arise (by 2026). And it remains a reliable, cost-effective solution in the long term, for reasons I will discuss later in my testimony.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO SHERCO SOLAR 1, 2, AND 3 IN THIS RATE CASE?

A. The Company requests that the Commission find that the Company's addition of Sherco Solar 1, 2, and 3 is prudent and allow recovery of these resources in base rates.

A. Selection of Sherco Solar 1, 2, and 3

Q. PLEASE EXPLAIN WHY THE COMPANY CONCLUDED COMPANY-OWNED SOLAR AT SHERCO STATION WAS A REASONABLE WAY TO TIMELY MEET A PORTION OF THE SYSTEM NEED.

A. The Company's 2019 IRP analysis originally selected a Sherco combined cycle (CC) turbine to be constructed at the Sherco Station, but it also identified large-scale solar additions as a part of the preferred plan as a reliable and affordable way to meet the anticipated capacity need. The Alternate Plan Analysis discussed above was conducted to evaluate an alternative plan that would not rely on the Sherco CC (which was challenged by uneconomic gas supply issues) and would ensure our system remained reliable. The analysis showed that the Company could instead reutilize its interconnection rights at its retiring coal facilities to add substantial amounts of solar, wind and/or firm dispatchable generation at a lower cost than would normally be expected if those same resources were added through the MISO interconnection queue process. As Tables 5 and 6 below show, solar is the first generation resource added to the system in the mid-2020s, regardless of whether the model considers environmental externality values. In light of the June 2020 Analysis, the Company issued the RFP that led to the selection of Sherco Solar 1 and 2 at Sherco Station.

Table 5
NSP Alternate Plan Resource Additions by Year
(includes externality values)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	-	-	-	-	-	-	-	-	200	200	950
Solar	-	-	-	-	700	600	-	600	150	400	100
Firm Peaking	-	-	-	-	-	60	259	374	-	374	374
Storage	-	-	-	-	-	-	-	-	-	-	200

Table 6
NSP Alternate Plan North Dakota Scenario Resource Additions by Year
(excludes externality values)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	-	-	-	-	-	-	-	-	-	-	500
Solar	-	-	-	-	650	200	-	500	-	450	150
Firm Peaking	-	-	-	-	-	60	259	1,122	374	374	748
Storage	-	-	-	-	-	-	-	-	-	-	50

Q. PLEASE DESCRIBE THE COMPETITIVE SOLICITATION PROCESSES FOR SELECTING SHERCO SOLAR 1 AND 2.

A. In early 2021, the Company issued an RFP for solar proposals at the Sherco site. The RFP was specific to the Sherco site to ensure that the Company's existing interconnection rights would be reused by the new project, in order to save time and money. Three bids were submitted, which were reviewed under the oversight of our independent auditor (IA). Our IA, Guidehouse, validated our process, certifying that it believed the goals of our RFP were achieved, that project assessments were performed in a fair and consistent manner, and that there was no evidence that we unfairly advantaged any interested party or respondent to the RFP, including the Company's self-build proposals. After conducting this thorough and competitive RFP process, the Company determined that its combined bid with National Grid Renewables offered the most beneficial project to meet the identified capacity need. Sherco Solar as proposed was the cheapest project bid and was to be the cheapest utility scale solar on the NSP System. By leveraging the expertise of the Company and its partner National Grid Renewables, we were able to ensure the Sherco Solar 1 and 2 projects would maximize benefits to customers.

Q. DID THE COMPANY CONSIDER ANY OTHER ISSUES IN SELECTING SHERCO SOLAR 1 AND 2 THROUGH THEIR RESPECTIVE RFP PROCESSES?

A. In addition to that RFP, which offered valuable insight to alternative project pricing, we compared the chosen Sherco Solar 1 and 2 project to other solar resources on our system and in the region. Through this evaluation, we found that the proposed Sherco Solar projects would provide lower cost energy than any solar facility currently operating on the NSP system.

As in many parts of the country, there are long wait-times for approving new interconnected generation in MISO. Because of this significant congestion for interconnecting new generation, the only two ways to realistically meet the identified capacity need in time were to procure capacity from the MISO capacity market or use existing interconnection rights.

Procuring capacity from MISO's Planning Resource Auction was eliminated as an option for a number of reasons. First, the market can be volatile, and increasing exposure to that volatility would put customers at risk for high, unplanned costs. Additionally, the Company's size could significantly impact the availability of short-term purchased capacity. Indeed, these are the same reasons why the Company has not traditionally relied on MISO's capacity market to meet customer needs and planning reserve requirements, and instead plans to ensure we have the capacity resources needed to serve our customers. By making a commitment to continue adding new solar and firm dispatchable resources, instead of relying on the MISO capacity market, the Company continues to meet customer demand through long-term resource acquisition rather than short-term power purchases that can be susceptible to volatile and tightening wholesale power markets. The approach of owning generation resources or entering long-term contracts for generation has served NSP well in the past to mitigate customer risk.

The Company determined that utilizing its existing interconnection rights was the most cost-effective option to bypass significant uncertainty for new interconnections that would require additional time and money. MISO rules allow a new generation project to replace and utilize an existing interconnection right if: (1) the new generation is owned by the same entity as the retiring facility;

(2) the request for generator interconnection replacement is submitted at least one year prior to the date the existing generation facility will cease operation; and (3) the expected commercial operation date for the replacement facility will be within three years of the date the existing facility ceases operation. Accordingly, only a Company-owned facility, not a third-party-owned facility, could use the Company's exiting interconnection rights.

Q. HOW DOES THE REUTILIZATION OF EXISTING TRANSMISSION RIGHTS BENEFIT CUSTOMERS?

A. Reutilizing existing interconnection avoids the costs that would be assessed to a resource requesting new interconnection through the MISO queue process. The Company estimated, when analyzing the Sherco Solar 1 and 2 additions, that the potential opportunity cost of foregoing full reutilization of the interconnection rights associated with Sherco Unit 2 would be approximately $140 million to $350 million, based on then-current constraints in the MISO interconnection queue and the Company's observation of recent planning study cycles and assigned interconnection upgrade costs.

Q. DID THE COMPANY CONSIDER GAS GENERATION AT THE SHERCO SITE?

A. Yes. In addition to analyzing the site location and ownership models to best suit the identified needs, the Company considered what resource type would be the best fit. Solar generation at Sherco was determined to be superior to gas generation because there is not an existing gas transmission line in the area and constructing a new gas-powered generation plant at the Sherco site would be costly and could not be completed in the necessary timeframe. Maintaining generation at the Sherco Station by extending the life of the already retired Sherco Unit 2 was no longer feasible. Moreover, as discussed above, the retirement of our coal units is supported by analysis in our 2015 and 2019 resource plans. Accordingly, the Company determined that adding Company-owned solar at the Sherco site was the best way to cost-effectively and reliably meet the identified capacity need at the time it was projected to be needed, and into the future.

Q. PLEASE DESCRIBE THE COMPETITIVE SOLICITATION PROCESS FOR SHERCO SOLAR 3.

A. On August 1, 2022, we issued an RFP seeking at least 900 MW of solar or solar-plus-storage hybrid resources to come online by the end of 2025, including up to 300 MW of capacity to replace the remainder of the open transmission interconnection rights that would be available when Sherco Unit 2 coal facility retired at the end of 2023. The purpose of this RFP was to select resources to fill the identified system need by 2026 and to enable the Company to reuse the remainder of its interconnection that would become available upon Sherco Unit 2's retirement.

The RFP was open to projects connected directly to the distribution system in our five-state NSP System, in addition to transmission-interconnected assets located in MISO Zone 1. We accepted proposals for various project structures: Company ownership through build-transfers or self-builds, as well as PPAs. The Company sought projects that could achieve a commercial operation date (COD) no later than December 31, 2025, to meet our near-term identified capacity need. Table 7 below illustrates eligible project types for the RFP.

Table 7
RFP Eligible Project Types

Purpose	Sherco Interconnection Reuse	Additional Resource Capacity Needs
Geography	MISO Zone 1, reutilizing the Company's existing Sherco interconnection rights	• MISO Zone 1 (transmission-interconnected assets, or • NSP distribution system (distribution-interconnected assets)
Resource Types	Solar, Solar + Storage	Solar, Solar + Storage
Approximate MW Target	300 MWac	600 MWac
Minimum Size per Project Site	>5 MWac	>5 MWac
Project Structure	Build Transfer, Company Self-Build	PPA, Build Transfer, Company Self-Build
Timing	COD by December 31, 2025	COD by December 31, 2025

Q. WHAT WERE THE RESULTS OF THE RFP?

A. We received 80 proposals for 43 projects from 17 bidders, totaling 2,749 MW of solar and 940 MW/3,120 MWh of storage. The bids included one self-build proposal, 58 PPA proposals, and 21 build-transfer proposals. Despite the robust response, during bid evaluation, we found significant critical issues with many of the bids that would pose undue risk to the Company and our customers, thus reducing the number of proposals passing through to final evaluation to 24. Some of these bids represented various configurations or contract types for the same project. At the end of the RFP process, we shortlisted 464 MW of solar projects, spanning contract structures and interconnection locations and including our self-build proposal for Sherco Solar 3.

Q. DID THE COMPANY IMPOSE ANY PRICE SCREENS AS PART OF THE EVALUATION PROCESS?

A. Yes. Ultimately, the proposals we received in response to this RFP were generally higher in price than the generic solar resources modeled in the IRP. Accordingly, while the Company perhaps could have met our entire resource need with the projects that bid into the RFP, given the high cost of many of those bids, and our ability to create time and space for better pricing through short-term PPA extensions, NSP imposed a price cap that limited any resource additions to projects with prices that were **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] which has a levelized cost of energy (LCOE) of approximately $70/MWh.

Q. WHY DID THE THIRD-PARTY SHORTLISTED PROJECTS WITHDRAW?

A. During negotiations and finalization, a majority of the bidders withdrew their projects because they could not maintain the proposed prices submitted in their initial bids, or because they were unwilling to incur the risk of unforecasted costs and delays to interconnect the projects. For example, one bidder determined that the level of tax credits assumed in its PPA bid was not actually achievable, and thus it was no longer willing to move forward with the project at the originally proposed price. Several other projects faced challenges with interconnection – either based on siting or risk of higher than expected interconnection costs – and removed themselves from further negotiation. Ultimately, the only third-party bid that could proceed was the 100 MW Apple River project. This project executed a PPA with NSPW and not the Company.

Q. WHY DID THE COMPANY DETERMINE INCREASING THE SIZE OF SHERCO SOLAR 3 FROM 150 MW TO 250 MW WAS APPROPRIATE?

A. The original bid was for a 150 MW project. While the bid indicated the Company could potentially expand the project, it did not provide detail regarding this potential expansion. When the initial bids in the RFP failed to provide an option to fully fill the Company's expiring interconnection rights, the Company worked with the independent auditor and established a process to evaluate multiple options to fulfill the rest of the interconnection. Through this process, the Company determined that an expansion of the Sherco Solar 3 project (to 250 MW) presented the best opportunity to ensure the remaining interconnection rights were fully utilized.

B. Economic Analyses for Sherco Solar 1 and 2

Q. PLEASE DESCRIBE THE ECONOMIC MODELING THE COMPANY PERFORMED FOR SHERCO SOLAR 1 AND 2.

A. As discussed above, the Company updated its 2019 IRP in 2021 with analysis supporting an Alternate Plan. The updated modeling showed that the least-cost plan to prudently meet the identified capacity need in 2024–25 had become large-scale solar resources, coupled with material amounts of energy efficiency and conservation, under both the base assumptions included in the Company's Alternate Plan, which align with Minnesota requirements, as well as North Dakota planning assumptions, which exclude externality values for items like a societal cost of carbon.

The Company's updated analysis also examined the economics of Sherco Solar 1 and 2 specifically (as opposed to generic solar) and found that it would yield significant savings on a PVRR basis. The assumptions in this analysis included the benefits of the Inflation Reduction Act (IRA), which expanded tax benefits for clean energy resources in general, plus additional benefits for projects located in "energy communities." Specifically, assuming Sherco Solar 1 and 2 qualify for the full production tax credit (PTC) value and an additional 10 percent bonus for being located in an "energy community," the Company anticipates a total PTC value of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for the first 10 years of Sherco Solar 1 and 2. The Company is committed to returning the value of all tax credits the Company receives, net of any transaction costs, to our customers.

Q. What were specific results of the updated economic modeling for Sherco Solar 1 and 2?

A. Our updated analysis found that Sherco Solar 1 and 2 would yield significant savings on a PVRR basis. Table 8 below shows the specific results of our updated analyses comparing the reference case to both the Company's IRP Alternate Plan North Dakota Scenario with generic solar and to the North Dakota Scenario with generic solar replaced by Sherco Solar 1 and 2. The Company performed this analysis using North Dakota planning assumptions, which require the least-cost project and do not consider externalities.

As shown in Table 8 below, the Company's IRP Alternate Plan North Dakota Scenario with generic solar replaced by Sherco Solar 1 and 2 would result in a PVRR that is $466 million lower than the reference case, which would maintain the status quo. This result is consistent with the cost savings assumptions based on our generic solar costs.

Table 8
Updated (2021/22) PVRR Results for Sherco Solar 1 and 2

Analysis Case	2020–2045 Total System Cost Results ($ millions, PVRR)	2020–45 Delta from Reference Case
IRP Reference Case (IRA-Adjusted)	$35,903	—
Sherco Solar 1 & 2 Base Case (IRP ND Alternative, IRA-Adjusted)	$35,366	($537)
Sherco Solar Change Case (IRP ND Alternative Scenario + Sherco Solar Project, IRA Adjusted)	$35,437	($466)

Q. HOW DID THE PROJECTED LCOE FOR SHERCO SOLAR 1 AND 2 CHANGE AFTER IRA TAX CREDITS AND OTHER UPDATED MARKET CONDITIONS WERE TAKEN INTO ACCOUNT?

A. The LCOE estimate, after taking into account the project's assumed eligibility for the IRA's PTC and "energy community" bonus credit, and further assuming the sale or transfer of PTCs, is 24 percent lower than the LCOE projected prior to the passage of the IRA. Our updated estimate resulted in an LCOE of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for the Sherco Solar 1 and 2 projects, assuming that the projects qualify for the full 10-year PTC plus the 10 percent bonus credit under the "energy community" provision of the IRA.

Q. SHOULD THE COMMISSION TAKE INTO ACCOUNT CIRCUMSTANCES THAT HAVE ARISEN AFTER THE COMPANY FIRST MADE THE DECISION TO CONSTRUCT THE SHERCO SOLAR UNITS?

A. Yes. The Company's economic analysis of Sherco Solar 1 and 2 is bolstered by a number of factors that further demonstrate the decision to invest in solar generation at Sherco Station was reasonable, including preserving valuable interconnection rights, capitalizing on lucrative tax credits and market conditions, and attaining state regulatory goals.

C. Economic Analysis for Sherco 3

Q. WILL SHERCO SOLAR 3 QUALIFY FOR PTCS UNDER THE IRA?

A. Yes. As a Company-owned project, Sherco Solar 3 is well-positioned to take advantage of the solar PTC provisions in the IRA, to the direct benefit of our customers. We expect the project to qualify for the full PTC value and an additional 10 percent bonus for being located in an "energy community." In total, we expect a total PTC value of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for the first 10 years of the project.[2] As the Company has recently noted in other dockets, these estimates are dependent upon our current interpretation of IRS guidance and expectations regarding the PTC transfer market. The Company is committed to returning the value of all tax credits the Company receives, net of any transaction costs, to our customers.

Q. WHAT IS THE PROJECTED LCOE FOR SHERCO SOLAR 3?

A. The projected LCOE for Sherco Solar 3 is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. This LCOE estimate assumes that the Project qualifies for the 10-year full PTC plus the 10 percent bonus credit under the "energy community" provision of the IRA, which results from

[2] In 2022 dollars; credits are adjusted annually for inflation.

the Project being located at the Sherco site. It also assumes the sale or transfer of PTCs, with net benefits passed on to customers.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THESE MODELING RESULTS?

A. As a practical matter, the expected costs of the Sherco Solar 3 project are essentially the same, all other things being equal, as the alternative of relying on alternative capacity purchases. However, as I discussed above, the Company has a long-standing strategy of using Company-owned resources and long-term contracts to serve its customers' loads. This strategy protects our customers against the impacts of market volatility. By adding Sherco Solar 3, the Company will be able to meet its customers' needs using a stable, long-term resource, and will avoid the risk associated with relying on a sometimes volatile capacity market.

Q. HAS THE COMPANY BEEN ABLE TO IDENTIFY ANY OTHER SOLAR RESOURCES AVAILABLE BY 2026 THAT HAVE A LOWER LCOE THAN THE PROJECT?

A. No. The RFP did not produce any bids with a lower LCOE than Sherco Solar 3 once the Company finalized negotiations with the bidders of shortlisted projects.

D. Summary

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO SHERCO SOLAR 1, 2, AND 3 IN THIS RATE CASE?

A. The Company requests that the Commission find that the Company's planned addition of Sherco Solar 1, 2, and 3 is prudent and allow recovery of these resources in base rates.

Q. WERE THE COMPANY'S DECISIONS TO ADD SHERCO SOLAR 1, 2, AND 3 PRUDENT?

A. Yes. On the whole, the additions of Sherco Solar 1, 2, and 3 are prudent because using Company-owned solar at the site of the soon-to-be-retiring Sherco Coal Units, and using the Company's existing interconnection rights, was the most cost-effective solution to meet the relevant portion of the identified need at the time forecast to arise (by 2026) and remain a reliable, cost-effective solution in the long-term, i.e., without being exposed to the volatility of the MISO capacity market. The Company's competitive solicitation process for Sherco Solar 1, 2, and 3, alongside economic modeling and qualitative risk considerations, confirmed that building Company-owned solar at Sherco is the most prudent solution for timely meeting the identified capacity need.

Q. HAS THE COMPANY ANALYZED THE IMPACT OF MISO'S NEW DIRECT LOSS OF LOAD METHODOLOGY ON THE VALUE OF SOLAR RESOURCES?

A. Yes, we have. However, we continue to recognize significant uncertainty with respect to the probabilistic models MISO is using and the assumptions used to generate MISO's long-term forecasts of resource adequacy accreditation for certain types of generation resources. To address this, the Company now performs its resource planning in a way that isolates the entire NSP system and ensures that there is sufficient capacity to meet energy needs plus a margin every hour of the day. This means that, rather than relying on meeting MISO's uncertain resource adequacy construct, we are focusing on helping to ensure that we can meet all of our customers' energy needs every hour of the day regardless of MISO's requirements. With that said–while there may be a decrease in accredited capacity for Sherco Solar 1, 2, and 3–such decreases would occur around 2028, and MISO's indicative results are highly uncertain. In any event, Sherco Solar 1, 2, and 3 remain cost effective resources on an energy basis and are certainly more cost effective than resources that may be added in the future. Last, I note that the Company had been anticipating the seasonal accreditation construct at the time that the Sherco Solar resources were selected and based on that conservative assessment, the resources were reasonable to select at the time the decision was made and will continue to be necessary components of the NSP system into the future.

V. ADDITIONAL RESOURCES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I explain multiple additional ways the Company is meeting its capacity needs. As noted above, the Company has taken a portfolio approach to meeting its capacity needs in a reliable and cost-effective manner. The resources I discuss in this section are short-term and/or small resources, but they provide reliable capacity while the Company continues to analyze longer-term solutions to its capacity needs. Specifically, this section discusses: (A) the Company's decisions to enter into a five-year PPA extension with Manitoba Hydro for 200 MW capacity and energy plus 350 MW of capacity only, which will partially replace the existing 835 MW PPA that is set to expire in 2025; and (B) the extension of the Cannon Falls PPA. This section also discusses the Company's request to allow the Company to recover the costs of these decisions.

A. Manitoba Hydro PPA

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE MANITOBA HYDRO PPA.

A. The Company has entered into two new short-term PPAs at the existing Manitoba Hydro project: (1) a five-year 200 MW summer system sale beginning in June 2025; and (2) a five-year diversity exchange beginning in June 2025 for 350 MW in the first three years and 200 MW diversity exchange in the last two years. Under the diversity exchange, Manitoba Hydro provides capacity in the summer, and Xcel Energy provides Manitoba Hydro capacity in the winter. The existing expiring contract that is being replaced is for a 500 MW system sale and 350 MW diversity exchange.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO THE MANITOBA HYDRO PPA IN THIS RATE CASE?

A. The Company requests that the Commission find the five-year Manitoba Hydro PPA prudent and allow recovery of the capacity costs of the contract in base rates and the energy costs through the Fuel Clause.

Q. WHEN AND HOW DID THE COMPANY DECIDE TO EXTEND THIS PPA?

A. The Company has long relied on capacity and energy from Manitoba Hydro. By entering into a short-term PPA after the existing PPA expires in 2025, the Company will continue to take capacity and energy, albeit at a reduced amount, from Manitoba Hydro. The short-term extension preserves capacity to meet our system needs while allowing for further analysis and development of longer-term solutions.

Q. WHAT ARE THE COSTS ASSOCIATED WITH EXTENDING THE MANITOBA HYDRO PPA?

A. The costs associated with the PPA have two components, a capacity cost and an energy cost. The capacity cost is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS], and the energy cost is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

Q. WHY IS THE FIVE-YEAR MANITOBA HYDRO PPA PRUDENT AND IN THE PUBLIC INTEREST?

A. The five-year PPA with Manitoba Hydro will address near-term capacity needs, which are projected to begin in 2027. The five-year PPA, along with other actions, ensures we have sufficient capacity on our system while we develop longer-term solutions.

B. Cannon Falls PPA Extension

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE CANNON FALLS PPA AND EXTENSION THEREOF.

A. In order to add short-term capacity while the Company develops longer-term resources, the Company has extended the Cannon Falls PPA for 357 MW for an additional three years, beginning in May 2025 after the current PPA is set to expire. Pricing for the extension will be consistent with the existing PPA.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO CANNON FALLS PPA IN THIS RATE CASE?

A. The Company requests that the Commission find the short-term Cannon Falls PPA extension prudent and allow recovery of the capacity costs of the contract in base rates and the energy costs through the Fuel Clause.

Q. PLEASE DESCRIBE WHEN AND WHY THE COMPANY DECIDED TO EXTEND THE CANNON FALLS PPA.

A. Similar to our approach to Manitoba Hydro, by entering into a short-term PPA extension, the Company will continue to take capacity and energy from an existing resource. The short-term extension preserves capacity to meet our system needs while allowing for further analysis and development of longer-term solutions.

Q. WAS THE COMPANY'S DECISION PRUDENT?

A. Yes. The short-term extension of the Cannon Falls PPA will address near-term capacity needs. Our current Resource Plan shows a capacity deficit beginning in 2027. The short-term PPA, along with other actions, ensures we have sufficient capacity on our system while we develop longer-term solutions.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission find prudent each of the Company's resource decisions I have addressed in my testimony. Each resource is an integral piece of a larger portfolio, which will help the Company provide its South Dakota customers with affordable and reliable electricity. The resources are "prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers," as demonstrated by the quantitative and qualitative factors I have identified in my testimony.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.