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Direct Testimony and Schedules
Nicholas J. Detmer

BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE
MINNESOTA PUBLIC UTILITIES COMMISSION
STATE OF MINNESOTA

IN THE MATTER OF XCEL ENERGY'S PETITION FOR APPROVAL OF ITS 2023 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

MPUC Docket No. E002/AA-22-179

OAH Docket No. 21-2500-40336

DIRECT TESTIMONY OF

NICHOLAS J. DETMER

On Behalf of

NORTHERN STATES POWER COMPANY

May 1, 2025

Exhibit___(NJD-1)

Replacement Power Costs

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nicholas J. Detmer. My business address is 3500 Blake Street, Denver, Colorado 80205.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc., the service company for Xcel Energy, Inc. and its operating company subsidiaries, including Northern States Power Company–Minnesota, d/b/a Xcel Energy (NSPM, Xcel Energy or the Company). I am the Director of Market Operations and Analytics.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Company.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked in the energy industry for over 30 years. I began my career with Unocal in 1992 as an engineer and worked on numerous geothermal energy projects in the USA, Indonesia, Philippines, Central America, and South America. In 1996, I became a Financial Engineer, and in that role, I conducted economic analysis of development projects and capital improvement for Unocal Geothermal. Upon Unocal's divestiture of Geothermal Division in 1999, I joined Calpine Corporation in 2000 as an Operations Analyst and was promoted to Manager of Analytics in 2002. The primary role of the Calpine analytics group was to provide costing and economic analysis of power plants, as well as to advise Calpine's marketing group regarding power plant optimization. In 2004, I joined Xcel Energy in the Risk Management group as a Generation Modeling Analyst, where I operated production cost models used to provide budget and economic analysis support. I later became Manager, Commercial Operations, where I oversaw the Trading Analytics Group and then the Real-Time Dispatchers, before assuming my current position as Director of Market Operations and Analytics in 2020. I earned a Bachelor of Science degree in Petroleum Engineering from the Montana Tech School of Mines in December 1991 and a Master of Business Administration from Colorado State University in May 2002. I am a Professional Engineer in the State of Colorado, registration number 34792. My statement of qualifications is attached as Exhibit___(NJD-1), Schedule 1.

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

A. I first provide some background on the Midcontinent Independent System Operator (MISO) electricity market and how it prices electricity, as this background is useful in understanding the power cost issues in dispute in this proceeding. Next, I provide background on production cost modeling. I then provide the Company's testimony and analysis regarding the best estimate of Xcel Energy's incremental cost of power, incurred due to an outage at the Prairie Island Nuclear Generating Plant (PINGP or Plant) that began in October 2023, following damage to a control cable bundle at the Plant (the Event). I also provide the best estimate of the value of benefits received by Xcel Energy customers from the Plant's strong historical performance and from the Company's actions to avoid future outage costs following the Event.

II. MISO MARKET BACKGROUND

Q. CAN YOU DESCRIBE HOW THE MISO ELECTRICITY MARKET PRICES ELECTRICITY?

A. Yes. As its name indicates, MISO is an independent system operator, which is an independent organization that handles, among other things, electricity market facilitation for certain geographical electric markets. The MISO footprint covers multiple states, including all of NSPM's service territory and the service territory of Northern States Power – Wisconsin, d/b/a Xcel Energy (NSPW), as well as NSPM's and NSPW's (together, NSP or Total Company) transmission and generation assets. The MISO electricity market is a two-pass market that seeks to minimize costs across the footprint MISO manages. The first pass is the Day-Ahead market, and the second pass is the Real-Time market. Starting with the Day-Ahead market, Market Participants offer to sell all the available generation under their control to MISO. Simultaneously, Market Participants with load obligations bid to buy load from the market. A generation resource "clears" the market when it submits an offer to sell into the market, and that resource is needed to fulfill the load obligations of the market. The cheapest generation resource offered into the market will clear the market first, then the next cheapest, and so on. MISO determines from these bids and offers where supply and demand intersect, and from there sets a wholesale price based on the last generation resource required to meet the demand, referred to as the Locational Marginal Price (LMP). All resources that cleared the market sell energy at their LMP. The LMP is specific to generators and loads on the transmission grid, called Commercial Pricing nodes.

The prior explanation is simplified, and the real derivation of price is far more complex considering multiple variables such as minimum run times, start-up costs, hourly costs, transmission constraints, planned outages, start-up times, and required reserves to respond to disruptions on the grid. The Real-Time market essentially functions the same but works to address differences between Day-Ahead and Real-Time. Alternatively, one can think of the Day-Ahead market as a forecast and the Real-Time market adjusts to the actual conditions.

Q. CAN YOU PROVIDE EXAMPLES OF HOW THE TWO-PASS MARKET GENERALLY INFLUENCES FUEL COSTS THAT CUSTOMERS PAY?

A. Yes. Again, starting with the Day-Ahead market, each morning Market Participants submit their offer and bids to MISO for the next day (which starts at midnight EST). MISO then sets the Day-Ahead market prices by the afternoon in preparation for the next day so generators can plan accordingly.

The process for setting the Day-Ahead market prices is exemplified by a simple scenario. Assume Xcel Energy has a 100 Megawatt (MW) load that it must serve by buying energy from MISO. At the same time, Xcel Energy has two power plants selling energy to MISO. Put another way, the same Market Participant, in this case, Xcel Energy, is acting as both buyer and seller. Again, assume that one power plant generates 30 MW and costs $50/MWh and a second plant generates 90 MW and costs $25/MWh. Even though the 90 MW plant clears the market at $25/MWh, some generation from the second plant that offers to sell its generation at $50/MWh is required to fulfill the load demand of 100 MW. In this simple example, the LMP will clear at $50 (the lowest cost to serve all of the load). Load – the power purchaser – pays 100 MW x $50/MWh =

$5,000. The generators receive revenue according to the LMP, so the 90 MW plant revenues = 90 MW x $50/MWh = $4,500 and the 30 MW plant revenues = 10 MW x $50/MWh = $500. The Xcel Energy Market Participant, acting as both load and generation, received $5,000 for all the generation sold while paying $5,000 for the energy purchased resulting in a net market interaction of $0. Through the Company's fuel clause adjustment, the Company will pass 90 MW x $25/MWh + 10 MW x $50/MWh = $2,750 through to its customers. In other words, the market interaction described here results in Xcel Energy passing only the fuel costs from generating the energy to its customers, as the market buys and sells net to zero. Table 1 below illustrates the calculations.

Table 1
Example of MISO Day Ahead Market Pricing

LOAD PURCHASE		Load		Purchased		Load
		MW		MW	$/MWh	Payment
Load	Day Ahead	100		100	$50.00	$5,000
Total		100		100		$5,000
GENERATION (GEN) SALES		Available	Cost	Sold	LMP	Revenue
		MW	$/MWh	MW	$/MWh	Received
Gen 1	Day Ahead	30	$50.00	10	$50.00	$500
Gen 2	Day Ahead	90	$25.00	90	$50.00	$4,500
Total				100		$5,000
GEN COST		Available	Cost	Sold	Cost	Total
		MW	$/MWh	MW	$/MWh	Cost
Gen 1	Day Ahead	30	$50.00	10	$50.00	$500
Gen 2	Day Ahead	90	$25.00	90	$25.00	$2,250
Total				100		$2,750
Customer Cost						$2,750

If we introduce a third plant from a different, unrelated Market Participant that is 40 MW and cost $40/MWh then the LMP would clear at $40/MWh. The Company bought load at $40, the Xcel Energy 90 MW generator was paid $40/MWh, the unrelated Market Participant generator was paid $40/MWh, and the Xcel Energy 30 MW generator did not clear the market and thus received nothing. In this scenario, the Company's customers benefit by lowering the fuel clause adjustment costs by $100 (90 MW x $25/MWh + 10 MW x $40/MWh = $2,650). See Table 2 below.

Table 2
Example of MISO Day Ahead Market Pricing
Mixed Market Participation

LOAD PURCHASE				Purchased		Load
				MW	$/MWh	Payment
Load	Day Ahead			100	$40.00	$4,000
Total				100		$4,000

GEN SALES		Available	Cost	Sold	LMP	Revenue
		MW	$/MWh	MW	$/MWh	Received
Gen 1	Day Ahead	30	$50.00			
Gen 2	Day Ahead	90	$25.00	90	$40.00	$3,600
Gen 3	Day Ahead	40	$40.00	10	$40.00	$400
Total				100		$4,000

GEN COST		Available	Cost	Sold	Cost	Total
		MW	$/MWh	MW	$/MWh	Cost
Gen 1	Day Ahead	30	$50.00	0	$50.00	$0
Gen 2	Day Ahead	90	$25.00	90	$25.00	$2,250
Gen 3	Day Ahead	40	$40.00	10	$40.00	$400
Total						$2,650
Customer Cost						$2,650

Now we introduce the next complexity which is the Real-Time market. As I stated before, the Real-Time market is meant to balance out the changes that occurred from the time the Day-Ahead market completed its function. At midnight, the Real-Time market begins and essentially performs the same algorithms as the Day-Ahead market, but now has updated information. Using our prior example, the Day-Ahead load was 100 MW at $40/MWh, but let's assume the Real-Time load is 105 MW. Further assume the Real-Time LMP was $45/MWh. This scenario results in 100 MWs purchased at $40/MWh from the Day-Ahead market and the incremental load of 5 MW priced at $45/MWh in the Real-Time market. Whatever generator delivered the extra 5 MW would be paid $45/MWh for that generation. The Real-Time market impact to customers is that they would pay another $225 (90 MW x $25/MWh + 10 MW x $40/MWh + 5 MW x $45/MWh = $2,875). See Table 3 below.

Table 3
Example of MISO Real-Time Market Pricing

LOAD PURCHASE				Purchased MW	$/MWh	Load Payment
Load	Day Ahead			100	$40.00	$4,000
Load	Real Time			5	$45.00	$225
Total				105		$4,225

GEN SALES		Available MW	$/MWh	Sold MW	LMP $/MWh	Revenue Received
Gen 1	Day Ahead	30	$50.00			
Gen 2	Day Ahead	90	$25.00	90	$40.00	$3,600
Gen 3	Day Ahead	40	$40.00	10	$40.00	$400
Gen 3	Real Time	40	$40.00	5	$45.00	$225
Total						$4,225

GEN COST		Available MW	$/MWh	Sold MW	Cost $/MWh	Total Cost
Gen 1	Day Ahead	30	$50.00	0	$50.00	$0
Gen 2	Day Ahead	90	$25.00	90	$25.00	$2,250
Gen 3	Day Ahead	40	$40.00	10	$40.00	$400
Gen 3	Real Time	40	$45.00	5	$45.00	$225
Total						$2,875
Customer Cost						$2,875

Alternatively, if the Real-Time load were 95 MW, this results in a sale back to the market of 5 MW at $45/MW (load bought 100 MW of $40 power in the Day-Ahead market, and then sold back the excess 5 MW at $45/MWh in the Real-Time market). The netting of the load purchase, generation sales, and generation cost results in what customers paid.

Figure 1
Customer Cost Calculation

$$
\begin{aligned}
&Customer\ cost \\
&\quad = [Day\ Ahead\ (DA)\ Load\ x\ DA\ Load\ LMP)] \\
&\quad + [Real\ Time\ (RT)\ Load \\
&\quad - DA\ Load]\ x\ RT\ Load\ LMP - [DA\ Gen\ MW\ x\ DA\ Gen\ LMP \\
&\quad + [RT\ Gen\ MW\ - DA\ Gen\ MW]\ x\ RT\ Gen\ LMP] \\
&\quad + Generation\ Cost
\end{aligned}
$$

Q. YOUR EXAMPLE ASSUMES THE LMP IS THE SAME FOR GENERATORS AND LOAD, YET LMP IMPLIES PRICES ARE LOCATIONAL. CAN YOU EXPLAIN?

A. Yes. Put simply, the difference between LMPs at a given Commercial Pricing node is a reflection of two elements: distance and transmission capacity. As to distance, the further a generator is from loads, the higher the transmission energy losses associated with that generator will be. The higher the losses, the more energy that is needed to meet the load at that Commercial Pricing node. As to transmission capacity, this is a function of the constraints of the transmission system. At times, the system can be "nearing capacity." When this occurs, the market disfavors generation in areas of constrained capacity. In tandem, these two factors cause locational cost discrepancies at the Commercial Pricing nodes, leading to different LMPs at each node.

Q. CAN THE LMP BE USED TO DETERMINE REPLACEMENT POWER COSTS?

A. No. As demonstrated above, Xcel Energy customers are not always exposed to MISO LMPs, but to the generation costs, which at times are lower than the MISO LMP. A production cost model, such as PLEXOS®, can account for the benefit of Xcel Energy's portfolio, effectively hedging the customer from high market prices, using the market when prices are lower.

III. PRODUCTION COST MODELING

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

A. In this section of my Direct Testimony, I describe the concept of production cost modeling and provide details on the inputs and assumptions of the specific software employed by the Company.

Q. WHAT IS PRODUCTION COST MODELING OF ELECTRIC SYSTEMS?

A. At the highest level, production cost modeling is a tool used to match supply (electric generation) with demand (customer load) to minimize overall system cost, while still honoring the operating characteristics of each electric generating unit. Production cost modeling software is used extensively in the electric power industry, by electric utilities, regional wholesale market operators, and other entities to make decisions for large, complex power systems. Simple analysis may sometimes be conducted using spreadsheets, but the intricacy of modern power operations, including the extremely large variety of inputs, requires the use of stronger tools when accurate and robust analysis is needed.

Production cost modeling software may be employed to forecast key values, such as the quantity of fuel needed for a specific generating unit in the future, what portfolio of electric generators will best minimize system pollutant emissions, or the expected economic value of a proposed transmission project. The software may also be used to look backward, such as to evaluate previous decisions or events. This is called a counterfactual study – in essence, what would overall system cost have been with a different set of facts (i.e., if a different decision had been made). The "engine" of a production cost model is known as an optimization solver, which uses mathematics to solve an objective function. These types of solvers are widely used in other industries such as mining, supply chain, manufacturing, or any industry requiring coordination of complex processes to achieve a result.

Q. WHAT IS AN OBJECTIVE FUNCTION?

A. An objective function is, fundamentally, a goal of a study. Goals could include minimization of fuel usage in a supply chain problem, maximization of resource output in a mining operation, or minimization of costs to meet customer demand on the power grid, all while honoring "constraints" on the system in question. These constraints could be machinery cycle times, required cool down periods, or maximum flow on a transmission line, all examples of constraints a modeler acting to solve a problem must honor while finding a solution (i.e., achieving the objective).

Q. HOW IS THE PRODUCTION COST MODELING SOFTWARE SET UP FOR A STUDY?

A. A production cost modeling software tool houses assumptions, constraints, and other information and converts them into one large mathematical equation for the solver engine to process. If the objective function of a study (the goal) is to minimize costs for a portfolio of power plants, then the associated equation would equal the sum of the power plant costs for each hour over the study horizon. These costs could include fuel costs, non-fuel (overhead) operations and maintenance costs, or even emissions costs. The equation must account for system constraints such as generating unit minimum run times, maximum capacity at a particular generating facility, or spinning reserve requirements for the overall power system. Some of these constraints are chronological in nature; the solution cannot expect a generating unit to produce full output in one hour if the same unit was shut down in the previous hour.

Q. WHY IS IT NECESSARY TO USE PRODUCTION COST MODELING SOFTWARE?

A. NSP has a large electric generation portfolio with more than 120 generating units, each with their own unique costs and operating characteristics. There are quite literally millions of possible combinations of these inputs. The optimization engine is charged with "solving" the objective function, finding the combination of inputs that minimizes production costs to the greatest possible extent. Production cost modeling optimization engines are sophisticated and powerful; indeed, they were initially developed in academia and enhanced by companies such as IBM. They reduce the problem by eliminating unreasonable or impossible outcomes and deliver results in reasonable computing time. An entire industry is dedicated to selling proprietary software for use in power system operations; ProMod®, GenTrader®, and PLEXOS® are all standard production cost modeling software packages used in the utility space.

Q. WHAT DO THE RESULTS OF PRODUCTION COST MODELING LOOK LIKE?

A. Once the study inputs are loaded into the software, the user specifies desired output parameters. These could include hourly generation from each generating unit, total daily system costs, quantity of fuel consumed, and which generating unit is carrying operating reserves. The models have a "run" button, which triggers the compilation of the cost equation and sends the study to the optimization engine. As the engine solves, the software records the requested outputs into a database of the solution that best achieves the objective function (the goal of the study).

Q. WHICH PRODUCTION COST MODELING TOOLS ARE USED BY THE COMPANY?

A. The Company has licensed several different software packages, each used for specific purposes. The Company employs EnCompass® for electric resource planning, while transmission studies are conducted using ProMod®, GridView®, and PSS@E®. PLEXOS® is used for mid-term studies (i.e., those extending between approximately one month and five years), and PCI Energy Solutions LLC (PCI)'s GenTrader® is used for studies that are usually one month or shorter in length. These tools are widely used in the industry and are relied upon throughout the country for utility decision-making and post operations analysis.

IV. CALCULATIONS OF REPLACEMENT POWER COSTS DURING OUTAGE

Q. CAN THE INCREMENTAL POWER RELATED COSTS INCURRED BY XCEL ENERGY DURING THE OUTAGE BE PRECISELY DETERMINED?

A. No. Due to the interaction of the Company's system and the complexity of the energy market as a whole, it is not possible to calculate with complete precision the costs incurred as a result of any particular outage. Determining the exact costs associated with an outage would require that we precisely calculate what Xcel Energy's costs would have been had an outage not occurred, essentially recreating a history that never happened. Because many variables – including the outage itself – affect energy market prices, we must instead make reasonable assumptions in our modeling efforts to recreate a hypothetical "what if" scenario. To calculate the replacement energy costs, then, we must determine what our costs would have likely been had the outage not occurred. To do this, we rely on the production cost modeling software PLEXOS® to approximate what would have occurred without the outage at the Plant and to develop a reasonable estimate of any incremental power costs incurred during the outage.

Q. CAN YOU BRIEFLY DESCRIBE THE ENERGY COST MODELING XCEL ENERGY HAS USED IN DEVELOPING ITS ESTIMATE OF THE INCREMENTAL POWER COSTS INCURRED DURING THE OUTAGE?

A. Yes. Xcel Energy has multiple assets, along with access to the MISO energy market, to potentially replace a plant that has experienced a forced outage. Due to the operation of the MISO energy market, as explained above, and the various assets available in the Company's generation portfolio, the problem of determining replacement cost is immensely complex. To deal with this complexity, the Company can utilize the same optimization software model that it uses for planning, budgeting, and decision-making to retroactively evaluate replacement costs. The model utilizes a complex time-series decision tree that seeks to determine the lowest cost series of decisions over the study period. The model requires power plant physical and cost characteristics (such as a unit's ability to run at full capacity and unit fuel costs), renewable generation forecasts, load forecasts, impacts from plant outages, and gas and electricity market forecasts. By retroactively inputting actual data, Xcel Energy can arrive at the best estimate of energy costs for the study period. Then, by changing a plant from outage to available, the model can derive the costs resulting from the unit having been available. The difference between the two model results is the incremental cost of power.

Q. PLEASE EXPLAIN THE PROCESS OF USING THIS MODEL TO DETERMINE THE INCREMENTAL COST OF POWER.

A. To model the cost of replacement power needed for the PINGP outage, the Company created a "base case" in PLEXOS® representing actual operations without PINGP, unit availability, fuel costs, wind generation, customer loads, and MISO market prices. Once the base case was calibrated, meaning the model closely resembled actual operations, the total system costs were extracted for the study horizon. The base case was then modified into a "change case"—a hypothetical scenario with different inputs than the base case—to assess the impact of different scenarios. In this instance, the base case was modified by making PINGP available for the period and total system costs are extracted from the model results. The difference between the base case and the change case yields the estimated costs of the PINGP outage.

Q. WHAT DID YOU ESTIMATE THE INCREMENTAL COST OF POWER TO BE USING THIS METHODOLOGY?

A. As shown in Attachment C of Exhibit___(NJD-1), Schedule 2, the Company's Supplemental Response to Department of Commerce Information Request 35, using this methodology, we estimated the total incremental power cost for the NSP System during the PINGP outage (for both Units 1 and 2) to be approximately $48.5 million ($34.3 million for the Minnesota jurisdiction).[1]

[1] As noted by Company witness Allen D. Krug, the Company no longer asserts that the final dollar estimates of replacement power costs or of the benefits and offsets are protected data.

V. AVOIDED FUTURE COSTS DUE TO WORK PERFORMED DURING OUTAGE

Q. ARE THERE OTHER CONSIDERATIONS RELEVANT TO THE COMMISSION'S DECISION ON THIS MATTER?

A. Yes. Company witnesses Allen L. Hiser and Carl R. Bible discuss how the cable replacement work performed by the Company during the outage enabled the Company to avoid or shorten total outage days that would otherwise have occurred in the future, meaning the Company also avoided future replacement power costs that otherwise would have been passed on to customers. Specifically, had the Company not fully replaced the control cables during the outage, that replacement work would have been required either as part of the subsequent license renewal (SLR) at PINGP or following a cable failure.

Q. IS IT POSSIBLE TO DEVELOP ESTIMATES OF THE AVOIDED REPLACEMENT POWER COSTS, DUE TO THESE AVOIDED OR SHORTENED OUTAGES?

A. Yes, but not with great precision. First, the exact timing and duration of these avoided or shortened outages must themselves be estimated, since replacement power costs can vary significantly on a day-to-day basis. Then, it is possible to at least develop a general estimate of the replacement power costs had the outages actually occurred by making a number of simplifying assumptions. While these estimates are just that, the avoided costs are real benefits that customers will receive due to the work done by the Company during the outage. In other words, the difficulty is not in determining *whether* our customers will benefit by the avoidance of these future outage days, but rather in determining the *amount* of these benefits.

Q. CAN YOU GIVE AN APPROXIMATE VALUE OF THE INCREMENTAL POWER COSTS AVOIDED BY REPLACING THE CONTROL CABLE DURING THE OUTAGE?

A. As discussed in Attachments A and C to Schedule 2, the Company considered three different scenarios, had it not replaced the control cable during this outage. Case 1 considered the impact of needing to replace the cable as part of the SLR. The Company estimates it avoided a total of 93 days of outage time compared to cable replacement following inspection of the DC cables as part of the SLR. This was based on a set of conservative assumptions in which the Company discovered the need to replace the cable and was able to perform the replacement work in the least disruptive way. Using certain simplifying assumptions, I estimate the value of this avoided replacement power to be approximately $26.5 million on a Total Company basis, as further shown in Schedule 2 (approximately $20.5 million for the Minnesota jurisdiction).

Q. ARE THERE OTHER SCENARIOS WHERE CABLE REPLACEMENT WOULD HAVE BEEN REQUIRED, LEADING TO OUTAGES AT PINGP?

A. Yes. As also discussed in Schedule 2 and further discussed by Company witnesses Hiser and Bible, if the Company did not discover the need to replace the cables through an inspection, cable failure would have eventually resulted in a forced outage of one or both units. Case 3 assumed one of the units was in a planned refueling outage (i.e., already shut down) at the time the online unit tripped, such as what occurred in 2023, then avoided outage days would be equivalent to the entire tripped-unit forced outage duration reviewed here, plus the additional outage days incurred on the unit already shutdown for refueling. Alternatively, Case 2 assumed both units were running, meaning cable failure would have resulted in a dual unit reactor trip. In this scenario, avoided outage days could again be determined using the data from the 2023 outage and applying the duration of the Unit 1 cable replacement outage to both units.

Finally, if the cable began to fail intermittently (or gradually fail), there is potential that cable troubleshooting activities could identify the need for cable replacement and a future dual unit outage could be planned. This would result in the same modeling as Case 1, the "cable replacement after licensing inspections" previously described.

Q. CAN THE AVOIDED INCREMENTAL POWER COSTS IN THESE SCENARIOS BE ESTIMATED?

A. Yes, subject to the limitations previously discussed. In the Case 3 scenario where one of the units was in a planned refueling outage at the time that the online unit tripped, the Company estimates 196 avoided future outage days, resulting in a value of avoided incremental power costs of approximately $68.9 million on a Total Company basis (approximately $53.2 million for the Minnesota jurisdiction).[2]

In the Case 2 scenario, where both units were operating at the time and cable failure resulted in a dual reactor trip, the Company estimates 208 future outage days avoided, resulting in a value of avoided incremental power costs of approximately $66.6 million on a Total Company basis (approximately $51.4 million for the Minnesota jurisdiction). Seasonality references differ between

[2] I would note that while Schedule 2 correctly stated estimated avoided incremental power costs of $68.9 million on a Total Company basis, it incorrectly stated that the Company avoided 192 (as opposed to 196) future outage days.

the two model runs, producing a slightly lower total estimated cost for this longer outage due to the differences in seasonal pricing.

Q. WERE ANY OTHER INCREMENTAL POWER COSTS AVOIDED BY WORK PERFORMED DURING THE OUTAGE?

A. Yes. As discussed by Company witness Bible, the Company proactively completed various additional projects during the outage that were scheduled to be completed during future planned outages, including cooling water pump strainer inspections, control valve packing leak adjustments, condenser cleaning, Unit 1 containment crane maintenance, valve diaphragm replacement, and micro-processing card replacement on the Unit 2 turbine. By pulling-forward these projects from planned future outages, customers received a measurable benefit by avoiding future incremental power costs associated with those future outages. To quantify the incremental costs avoided, these pulled-forward projects were assessed based on labor hours expended, which correlates to the equivalent of approximately 8 avoided future outage days, as shown in Schedule 2, Attachment B. This results in a value of avoided incremental power costs of approximately $2.4 million on a Total Company basis (approximately $1.8 million for the Minnesota jurisdiction).

VI. AVOIDED REPLACEMENT POWER COSTS DUE TO THE PLANT'S STRONG HISTORICAL PERFORMANCE

Q. HOW HAS THE PLANT PERFORMED HISTORICALLY?

A. As Company witnesses Krug and Bible discuss, PINGP has a strong performance record, achieving a combined 96 percent capacity factor in 2022, and a combined average capacity factor of 95 percent between 2018 and 2022. Additionally, the Company experienced a record-setting run of 670 days of uninterrupted operation at PINGP Unit 1 from 2018 to 2020, and a record setting run of 704 days on Unit 2 from 2019 to 2021.

Q. IS THE PLANT'S HISTORICALLY STRONG PERFORMANCE RELEVANT TO THE COMMISSION'S CONSIDERATION OF THIS MATTER?

A. Yes. As also discussed by Company witness Krug, Xcel Energy's strong performance record at PINGP has benefited customers by providing consistent, reliable, and cost-efficient baseload power, including during periods of extreme weather, including the 2019 polar vortex and the 2021 Winter Storm Uri. The financial benefit of the Company's superior past performance should be considered when determining whether a refund is appropriate, so that any disallowance is based on a reasonable standard of performance in relation to other utilities.

Q. IS IT POSSIBLE TO QUANTIFY THE VALUE OF THE STRONG OVERALL PERFORMANCE OF PINGP PRIOR TO THE OUTAGE?

A. Yes. The financial benefit of the superior performance of PINGP from 2018 through 2022 can be quantified by comparing PINGP overall performance during that time to the industry norm. Doing so shows that PINGP performance was well below the industry median offline hours in that period. In fact, PINGP generated 2,577 GWh above Company forecasted output during that time increment benefiting customers by over $50 million dollars over that time period. In extending the time horizon to include the outage, PINGP's offline hours exceeded industry median by 51 percent. See

Exhibit___(NJD-1), Schedule 3, for a comparison of Prairie Island's Historical Performance vs. Industry. Therefore, as Company witness Krug discusses, if the industry median is used as a benchmark, 49 percent of the net costs should be removed from any total disallowance.

VII. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE YOUR DIRECT TESTIMONY?

A. PINGP is operated in an energy market construct that includes both day-ahead and real time transaction pricing references. That market uses an LMP basis, but the Company also considers non-market pricing, when possible, to create customer benefits. For that reason, the LMP was not used to estimate the incremental power costs incurred during the outage at issue.

In addition, the precise replacement costs from the outage in this case cannot be known due to system and market pricing complexities. In making its cost estimate, the Company instead employed production cost modeling tools used to orchestrate a best-available value. In this instance the Company used the PLEXOS® model. The PLEXOS® model incorporates a time-series decision tree that seeks to identify the lowest cost choices within an imposed time period. The model first refers to a base case, established using input values representing approximations of actual conditions absent PINGP operation, yielding a total system cost estimate result. Next, the base case is adjusted to approximate the system production *including* PINGP operation. The difference between the base and this "changed" case provides the outage cost estimate. The difference calculated in this case, representing the estimated outage cost, is $48.5 million ($34.3 million for the Minnesota jurisdiction).

The Company further demonstrates that the cable work performed would have incurred a distinct expense had it been either pre-scheduled or resulted from a spontaneous cable failure. The Company values the avoided cost of a least-disruptive, pre-planned scenario avoiding 93 outage days as an estimated $26.5 million on a Total Company basis and $20.5 million for the Minnesota jurisdiction.

In an instance of a spontaneous cable failure curtailing both units, the Company estimates the outage to avoid 208 outage days with an estimated avoided incremental power cost of $66.6 million on a Total Company basis and $51.4 million for the Minnesota jurisdiction.

For a hybrid-type scenario involving a single-unit planned outage with the still-operating unit experiencing an unplanned failure, the Company estimates avoiding 196 outage days and estimates a total avoided incremental power cost of $68.9 million for the Total Company and $53.2 million for the Minnesota jurisdiction.

The Company also identifies customer benefit in supplemental work performed during the outage that would otherwise have occurred in a distinct outage instance, now avoided. This value relies on the estimate of eight days of labor hours avoided, totaling $2.4 million on a Total Company basis and $1.8 million for the Minnesota jurisdiction.

Lastly, the Company refers to PINGP's overall above-average performance between 2018 and 2022 when compared to the industry. This time period includes both the 2019 polar vortex event and Winter Storm Uri in 2021. As Company witness Krug also discusses, this superior performance should be recognized in determining the appropriate amount of any customer refund. To create a value increment for this success, the Company quantified total PINGP generation over its forecasted level of production from 2018 to 2022. PINGP produced 2,577 GWh over its forecasted output for that period, delivering over $50 million dollars in customer benefits. When combining this historic performance with the time period including the outage at issue, PINGP exceeded the industry performance median outage hours by 49 percent. Therefore, the Company recommends use of a 51 percent performance differential to "benchmark" PINGP performance to the industry-median performance. When combined with other offsets already identified, this results in a customer refund of $6.1 million for Minnesota jurisdiction (see Table 4 for breakdown).

Table 4
Summary of Customer Refund (Minnesota Jurisdiction)
(See Schedule 2, Attachment C)
($ rounded to 0.1 million)

Replacement Energy Costs	$34.3
-Supplemental Work	$ 1.8
-Avoided 2029 Costs	$20.5
Total Before Performance Adjustment	$11.9
x Historic Performance Adjustment	51%
Customer Refund	**$ 6.1 million**

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Statement of Qualifications
Nicholas J. Detmer

I have been employed by Xcel Energy since 2004, in the areas of Risk Analytics, Commercial Operations and Market Operations and Analytics. In my current role as Director of Market Operations & Analytics, I am responsible for the oversight of transmission service acquisition on behalf of customers, representing Xcel Energy's interest concerning markets at SPP and MISO, the utilization of production cost models such as PLEXOS® and GenTrader®, and data mining and analytics support for Commercial Operations.

EMPLOYMENT

June 2020-Present	Director, Market Operations & Analytics – Xcel Energy
July 2004-June 2020	Manager, Commercial Operations – Xcel Energy
2004-June 2004	Analyst, Risk Analytics – Xcel Energy
2002-2004	Manager of Analytics – Calpine Corporation
2000-2002	Operations Analyst – Calpine Corporation
1996-1999	Financial Engineer - Unocal
1992-1996	Engineer - Unocal

EDUCATION

Master of Business Administration
Colorado State University

Bachelor of Science – Petroleum Engineering
Montana Tech School of Mines

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☒ **Public Document – Not-Public Data Has Been Excised**
☐ **Public Document**

Xcel Energy		Supplement Information Request No.	35
Docket No.:	E002/AA-22-179		
Response To:	Minnesota Department of Commerce		
Requestor:	Katherine Arnold		
Date Received:	October 1, 2024		

Question:
Topic: Calculation of Ratepayer Refund
Reference(s):

State the amount of the refund that you believe Xcel Energy's ratepayers should receive as a result of Xcel Energy's imprudence that resulted in the outages of Prairie Island One and: a) explain in detail your calculation; 2) produce each document that either supports or refutes your calculation. Please include both Total Company and Minnesota Jurisdictional amounts, including support for allocator used.

Response:
The Company objects to this request on the grounds that it is premature and overly burdensome. In particular, this request relates to the contested case ordered by the Commission at the hearing on September 19, 2024 in Docket No. E002/AA-22-179. We do not yet have an order from the Administrative Law Judge (ALJ) related to the discovery procedure or schedule for this case; we will provide responsive, non-privileged documents in response to discovery requested consistent with the schedule and procedures established by the ALJ.

Supplemental Response:
The Company maintains its initial objections to this request. The Company further objects to this request to the extent it assumes imprudence, which the Company continues to dispute.

Without waiving any objections, the Company states that a customer refund, if any, should account for a number of considerations, described in more detail below.

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A. Refund Considerations

First, a customer refund, if any, must account for the benefits customers received from the steps the Company took to avoid future outages that would result in customers paying for replacement power costs in the future. These steps include:

Replacing rather than repairing the DC cables. The affected direct current (DC) control cables include 30 cables of 5 shielded twisted conductor pairs each, approximately 1,300 feet long. The cables are direct buried from the substation to the plant in a common trench and are terminated in common locations. The cables supply control power to assets required to operate both units of Prairie Island at power. These assets include transformers supplying offsite power to the plant as well as output breakers for both main electrical generators to supply generated power to the grid.

Upon investigating the event, the Company discovered that the damaged control cables were aging (about 50 years old) and at risk of additional water intrusion as evident by green discoloration of the copper conductor and jacket embrittlement. Eventually, this degradation would have led to one of two outcomes: (1) in the course of the Prairie Island Nuclear Plant Subsequent License Renewal process, the plant would be required to undertake cable aging management inspections and testing, which would likely have revealed the need for replacement; or, (2) a need to replace the cables would be recognized after cable failure, indicated by an increasing number of ground faults over time, causing electrical anomalies in performance of various plant equipment, such as loss of transformers or the generator output breakers, either of which would result in a trip of the units. As a result of either (1) or (2), the DC cables would have had to be replaced at a future date. By fully replacing the DC cables during the 2023 outage, the Company avoided future outage days. We have estimated the impact of each of these scenarios below.

Cable Replacement after Licensing Inspections. If we performed an inspection of the DC cables as part of the Subsequent License Renewal process and, assuming that as a result of that inspection, we identified the need to replace the cables, the Company would plan a dual-unit outage for the cable replacement. As indicated above, these cables connected to systems across both units, and these cable bundles were twisted together, coming into the same multi-unit terminal box, resulting in cable components serving both units being in close proximity to one another. Due to the complexity of the cable location and the plant assets the cables support, this would have required a planned dual-unit outage. We

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would plan the dual-unit outage to coincide with a planned refueling outage for one unit.

The alternative to a dual-unit outage—planning two, single-unit outages—would create a high risk of tripping the online unit during replacement of the offline unit's cables and increase overall outage time. An attempt to separate the cable bundles would likely result in a reactor trip of the other online unit, either due to damage of surrounding conductors or due to the fact that these cable bundles are twisted together and come into the same multi-unit terminal box. The close proximity of cables from each unit also creates the risk of incorrectly disconnecting and reconnecting the wires. These risks are eliminated by performing the cable replacement with both units offline.

In order to determine avoided outage days for a future dual-unit outage to replace the cables, the Company determined that the replacement would be executed the same way it was executed during the 2023 dual-unit outage, excluding those activities that could be performed in advance of the outage. The following assumptions were made:

1) While 100 percent of the trenching activities for the 2023 cable replacement were undertaken during the outage, we assumed the avoided future outage would include reduced trenching activities, accounting only for those portions that require the units to be offline: a section going into the substation and a section going to the plant boundary.
2) While all the cable was laid during the 2023 outage, we assumed that cable would be partially laid prior to the avoided future outage.
3) We assumed that the avoided future outage would take place in conjunction with a typical refueling outage on one of the units, planned for approximately 27 days without major work scope other than the cable replacement project. We removed the refueling work window and associated outage days from the total avoided future outage days. In other words, the Company's total avoided future outage days include only the days required *beyond* refueling to perform the cable replacement.

After removing overlapping defueled work on Unit 2, the avoided future outage days for Unit 2 is 45 days and for Unit 1, 48 days. Total avoided future outage days for both units is therefore 93 days.

To quantify the avoided replacement power costs for those days, the Company assumed an outage in 2029 when Unit 2 is scheduled for refueling and utilized PLEXOS to evaluate the avoided costs. As shown in the data identified by

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Case 1 on the "PI Summary" tab of Attachment A to this response, the PLEXOS model assumed an additional 47 days of outage at Unit 2 and 42 days at Unit 1 for a total of 87 avoided future outage days. The avoided replacement power costs had the Company needed to perform this work in 2029 are estimated to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

Cable Replacement after Cable Failure. As discussed above, if the Company did not discover the need to replace the cables through an inspection, cable failure would have eventually resulted in a forced outage of one or both units. If one of the units was in a planned refueling outage (i.e., already shut down) at the time the online unit tripped, such as what occurred in 2023, then avoided outage days would be equivalent to the entire tripped-unit forced outage duration, plus the additional outage days incurred on the unit already shutdown for refueling. In the case of the 2023 planned Unit 2 refueling outage, 63 days were planned for refueling and baffle and clevis bolt replacements. A typical refueling outage without major scheduled projects would be scheduled for about 27 days. This includes 7 days up front to shut down and remove fuel from the core, 6 defueled outage activity days, and 14 days to refuel the reactor, complete required testing, and start up. Using the 2023 outage data, Unit 1 was the online unit that tripped and resulted in a 101-day outage (October 19, 2023 – January 27, 2024). See the Company's response to DOC IR No. 22. The 2023 outage included investigation, project planning, and execution, and we would expect the same required activities if this happened in the future. Therefore, in an avoided future forced outage, we would anticipate the same 101-day duration for the tripped unit (Unit 1 in this scenario). These 101 days would limit the duration of the avoided future outage; in other words, the refueling unit could not be started up until after the tripped unit is brought online due to refueling-outage-specific startup testing required on the refueling unit. To determine avoided outage days on the refueling unit (Unit 2), the planned defueled 6 day window on the refueling unit could be subtracted from the 100 (this is work that would have to be performed regardless of the cable being replaced), resulting in 92-avoided outage days on Unit 2. Combining avoided outage days for both units, a total of 192 future outage days were avoided. Using the PLEXOS model, and as shown with the data related to Case 3 in the "PI Summary" tab of Attachment A, the replacement power costs had the Company needed to perform this work in 2029 are estimated to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

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Alternatively, cable failure could result in a dual-unit reactor trip, i.e., neither unit is in refueling and both units trip. In this scenario, avoided outage days could again be determined using the data from the 2023 outage and applying the duration of the Unit 1 cable replacement outage to *both* units. Again, the Unit 1 outage was 101 days. In addition, 6 days are added for Unit 2 start-up activities after Unit 1 is online, bringing the Unit 2 outage duration to a total of 107 days. Taken together, in this scenario, a total of 208 future outage days were avoided. Using the PLEXOS model, and as shown with the data related to Case 2 in the "PI Summary" tab of Attachment A, the replacement power costs had the Company needed to perform this work in 2029 are estimated to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

If the cable began to fail intermittently (or gradually fail) as could be evident in electrical grounding and various equipment alarms or relays and breakers opening, there is potential that cable troubleshooting activities could identify the need for cable replacement and a future dual-unit outage could be planned. This would result in the same modeling as "cable replacement after licensing inspections" as previously described.

Using the period in which the plant was offline to pull forward and perform work that was already scheduled for a future outage. As shown in Attachment B to this response, the Company completed various projects during the 2023-2024 outage that were scheduled to be completed during future outages. Based on labor hours, the work performed on these pulled-forward projects correlates to the equivalent of approximately 8 avoided future outage days. Using the results from the planned outage case above (Case 1), an estimate was made by dividing the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** by 89 days to derive a daily rate of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** per day and multiplying by 8 days for avoided replacement power costs of this pulled-forward elbow replacement project of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

Second, a refund to customers, if any, should consider the benefits customers have received from the Company's historical performance of the plant compared to other industry participants. As seen in Attachment A to the Company's July 30, 2024 Reply Comments in this docket, the Company's overall performance from 2018 through 2023, was superior to median industry performance. For example, as supported by that prior Attachment A, the financial benefit of the Company's superior performance from 2018-2023 to our customers can be quantified by comparing the MWh

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generated during this time period to what we forecasted for unit performance, based on reasonable expectations for performance. Based on this comparison, the Company estimates that from 2018 through 2022, it generated approximately 2,577 GWh above our forecasted amount, resulting in estimated benefits to customers of approximately $50.6 million compared to normal operating performance. *See* July 30, 2024 Reply Comments.

If there are additional considerations that the Company determines could impact a customer refund, it will present those considerations in its testimony on this issue.

B. Refund Calculation

Taken together, the Company's offset calculations are provided in Attachment C to this response. Taking the PLEXOS model calculation of replacement costs provided in Attachment 1 to the Company's second supplemental response to DOC IR No. 30, assuming a jurisdictional allocation in 2029 of 77.3 percent based on forecasted sales, and applying the most conservative case for avoided outage days, Case 1, less the avoided costs for the additional pulled-forward work during the outage in 2023 and 2024, results in offsets that would lower any proposed customer refund to approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. This, however, does not account for the Company's superior historical performance, which provides further mitigating factors that the Company may account for as the case proceeds. For example, adjusting the refund to account for the amount of time the units were out compared to industry-median performance for the five-year period from 2018-2023 (51 percent), as opposed to the Company's industry-leading performance during that time, would further reduce any proposed customer refund to approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].**

As mentioned above, if there are additional considerations that the Company determines could impact a customer refund, it will present them in its testimony on this issue, including their impact on any refund.

Please note that this response as well as all of Attachment A and portions of Attachment C are marked as "Not Public" as they contain information the Company considers to be "not-public data" pursuant to Minn. Stat. §13.02, Subd. 9. This is information the Company considers to be "Trade Secret" information pursuant to Minn. Stat. § 13.37, subd. 1(b), because it has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

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		As to Objections	
Preparer:	Amanda J. Jepson	Preparer:	Lauren Steinhaeuser
Title:	Manager, Nuclear Regulatory Policy	Title:	Assistant General Counsel
Department:	HQ Nuclear Policy	Department:	Legal Services
Telephone:	(651) 212-1679	Telephone:	(612) 216-8274
Date:	March 28, 2025	Date:	October 11, 2024

Preparer:	Nicholas J. Detmer
Title:	Director, Market Operations and Analytics
Department:	Market Operations
Telephone:	(303) 571-7030
Date:	March 28, 2025

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Under Minnesota Stat. § 13.37, trade secret information is defined as including a compilation of data that "(1) was supplied by the affected individual or organization, 2) is subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, and 3) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use."

Attachment A is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material

1. **Nature of the Material:** The workpapers contain Confidential and Proprietary forecast modeling inputs from PLEXOS, including contract terms and forecasted market pricing.
2. **Authors:** The data is output from PLEXOS and prepared under the direction of Nick Detmer.
3. **Importance**: The workpapers contain competitively sensitive data related to modeling inputs and has economic value to Xcel Energy, its customers, suppliers, and competitors. The knowledge of such information could adversely impact future contract negotiations, potentially increasing costs for these services for our customers.
4. **Date the Information was Prepared:** The information was prepared in March 2025.

WORK ORDER	DESCRIPTION	When This Work Was Otherwise Scheduled to Take Place (future)	Date and Time Work Started	Date and Time Work Ended	Estimated Labor Hours
700010079	Air Leak on Threads going to SV-33434	1R34 - 9/2024	11/5/23 18:13:53	11/7/23 23:02:01	15
700071516	Replace CW-19-1 and Piping	Online - WW2402 (2nd week of January 2024)	12/5/23 07:51:53	1/2/2024 18:01	98
700080577	CV-39022 SV Continuously Venting	Online - Pre 1R34 (August 2024)	1/2/24 04:53:39	1/29/24 07:26:47	57
700107637	Install EC 601000004714	1R34 - 9/2024	1/3/24 09:51:16	1/9/24 12:26:44	57
700115392	Replace CW OUTL Manway Covers	1R34 - 9/2024	11/21/23 05:32:00	1/3/24 21:54:34	515
700115410	QIM_501000068274_CV-39013 Would Not Open	Online - Pre 1R34 (August 2024)	12/17/23 15:08:06	2/9/24 15:00:32	114
700115564	501000068209_CV-39062 Fails to Open	Online - Pre 1R34 (August 2024)	12/12/23 11:28:14	4/12/24 13:01:09	64
700118052	CV-39070 12 COND FLTR Demin Degraded	Online - Pre 1R34 (August 2024)	1/3/24 12:07:27	2/9/24 14:59:48	49
700118783	CV-39040 Needs Actuator Rebuild	1R34 - 9/2024	12/17/23 23:21:36	1/29/2024 4:12	50
700119911	CV-31037 Should be Dual Indication	1R34 - 9/2024	1/10/24 10:12:12	1/15/24 13:44:20	33
700119912	CV-31034 Should be Dual Indication	1R34 - 9/2024	1/10/24 10:10:29	1/15/24 13:45:09	40
700121758	501000071618_Check Valve Not Always Open	1R34 - 9/2024	11/14/23 19:12:20	2/10/24 03:28:01	51
700122984	121 MDCLP Baseplate NDE	Online ; Winter 2024	12/12/23 07:31:11	12/13/23 12:27:30	8
700125109	GMP ADAM-001012 CL STRNR INSP	Online ; Q1 2025	12/3/23 22:08:18	12/4/23 23:44:55	129
700125178	GMP ADAM-001 11 CL STRNR INSP	Online ; Q1 2025	12/5/2023 18:38	12/7/23 03:31:40	78
700125795	1 Ovation 12 SG Software Correct	1R34 - 9/2024	11/7/23 04:59:06	11/8/23 17:37:37	12
700125815	11 FWP LO Switch SPV Elimination LP Oil	1R34 - 9/2024	11/3/2023 16:54	1/10/24 08:47:55	109
700125816	12 FWP LO Switch SPV Elimination LP Oil	1R34 - 9/2024	11/3/2023 16:54	1/10/24 08:52:15	113
700126372	SV-33344 Replacement	Online ; Q1 2025	11/28/23 00:18:05	12/6/23 13:46:26	22
700126373	SV-33445 Replacement	Online ; Q1 2025	12/18/23 03:55:45	12/21/23 11:34:14	24
700127039	501000075522_NIS FAT Grounding Issue	1R34 - 9/2024	12/27/23 05:26:07	1/4/24 05:36:57	24
700127457	EOC Check Condition of CD-113-5	1R34 - 9/2024	10/25/23 01:30:09	1/27/24 02:33:47	141
700127458	EOC Check Condition of CD-113-4	1R34 - 9/2024	10/25/23 01:28:58	1/29/24 01:17:37	147
700127460	Replace CV-31096 Valve Internals	1R34 - 9/2024	10/24/23 00:02:12	1/28/24 15:55:02	154
700128419	Replace 1 YIC-111 per EC 601000003840	1R34 - 9/2024	1/5/24 05:35:40	2/22/24 22:35:36	21
700128697	Replace Elbow above CR-5-1	On dual unit forced outage list	11/10/23 07:00:18	2/1/24 11:06:05	1820
700130113	Inspect CT Stop Log Rail Guides	Online ; Q1 2025 (preference for dual unit outage)	10/25/2023 9:17	10/25/23 13:45:19	452
700130577	Clean U1 CDSR Outer and Inner Passes	Online ; Q2 2025	11/13/23 04:37:52	2/5/24 12:00:08	674
700130621	Troubleshoot/ Replace 11 CW Pump motor	1R34 - 9/2024	11/12/23 04:37:43	1/29/2024 9:36	965
				Total	**6036**

WORK ORDER	DESCRIPTION	When This Work Was Otherwise Scheduled to Take Place (future)	Date and Time Work Started	Date and Time Work Ended	Estimated Labor Hours
700044975	PINGP SWITCH YARD REL GRP ACT 2RSY	2/5/24 (WW2405)	12/13/23 07:03:36	12/22/23 14:10:52	186
700045913	PINGP Switch Yard Rel Grp act 2RY	2/5/24 (WW2405)	No Data	12/23/23 14:59:54	96
700087871	BIRD SPIKES MISSING NEAR 2RY AUX XFMR	2/5/24 (WW2405)	No Data	11/13/23 12:51:44	75
700103003	TD-7-6 has a steam leak and requires replacement	2R34 (10/2025)	1/10/24 04:48:58	5/16/24 09:09:01	132
700106759	(BKR 111C-22) 21 CLG WTR STRNR	Q1 2024	1/8/24 21:54:19	1/9/24 14:40:55	38
700108636	PE 6037: 2RY/XFMR, TRASFORMER MAIN	2/5/24 (WW2405)	11/18/23 13:58:20	12/23/2023 15:50	457
700110627	BKR 2RSX, PERFORM INTERNAL INSPECTION	2/5/24 (WW2405)	11/19/23 07:41:20	12/22/2023 11:23	487
700110993	Overhaul CV-31733	2R34 (10/2025)	1/13/24 10:38:00	1/23/24 03:32:06	47
700122088	TEST CLOSE AND TRIP COILS BKR 26-16 (BUS 26 SOURCE FROM D6 DSL GEN) ; LOW DC VOLTAGE MARGIN	Online D6 Diesel OOS Window - Q1 2025	2/15/24 07:29:11	2/22/24 06:40:52	162
700123555	GMP ADAM-001-21 CL STRNR INSP	Q1 2024	12/19/23 18:47:25	1/22/24 05:55:22	77
700125512	5Y PM - 2RSY,2RS XFMR FD TO 2RY XFMR,GCB MAINT and	2/5/24 (WW2405)	11/19/23 07:40:55	12/22/23 14:28:45	200
700125955	BKR 2RSY, PERFORM INTERNAL INSPECTION	2/5/24 (WW2405)	12/18/2023 15:19	12/22/2023 11:18	426
700126373	SV-33345 REPLACEMENT	Q1 2024	12/18/23 03:55:45	1/18/24 07:41:23	22
700126912	Verify 4 Drive clutches of each Detector	2R34 (10/2025)	1/4/24 04:47:44	1/27/24 13:01:38	64
				Total	**2469**

Total Outage Days Worked

Total Number Outage Days (October 19 - March 1)
135 Days

Person-Hours Worked Daily (1 Outage Day)
141,796 total internal/contract labor hours / 135 days = 1,050 hours = 1 outage day

Total Outage Days (Unit 1 and Unit 2)
8,505 total work scope add labor hours (Unit 1 and Unit 2) / 1,050 average labor hours worked = **8.1 outage days**
Unit 1 outage days worked = 5.7
Unit 2 outage days worked = 2.4

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E002/AA-22-179
DOC IR No. 35 - Supplement
Attachment C - Page 1 of 1

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2023-2024 Outage PI Replacement Costs - 'Production Cost Model (PLEXOS) Calculation Method

Total Plant (Prairie Island 1 & 2)

Month	NSP-Minnesota Replacement Power Costs	Minnesota Allocator	Minnesota Replacement Power Costs
	[PROTECTED DATA BEGINS		
Oct-23		71.44%	
Nov-23		70.92%	
Dec-23		70.77%	
Jan-24		70.22%	
Feb-24		70.78%	
Mar-24		70.47%	
	-		

Prairie Island 1

Month	NSP-Minnesota Replacement Power Costs	Minnesota Allocator	Minnesota Replacement Power Costs
Oct-23		71.44%	
Nov-23		70.92%	
Jan-24		70.22%	
Feb-24		70.78%	
Mar-24		70.47%	
	-		

Prairie Island 2

Month	NSP-Minnesota Replacement Power Costs	Minnesota Allocator	Minnesota Replacement Power Costs
Oct-23		71.44%	
Nov-23		70.92%	
Dec-23		70.77%	
Jan-24		70.22%	
Feb-24		70.78%	
Mar-24		70.47%	
	-		

Total Plant 2029 Avoided Replacement Power Costs

	NSP	**MN Allocator**	**MN**
Case 1		77.30%	
Case 2		77.30%	
Case 3		77.30%	
Pulled Forward		77.30%	

Total Plant Less 2029 Replacement Power Costs

	Case 1	Case 2	Case 3
Pulled Forward			
Industry-median performance			

Unit 1 2029 Avoided Replacement Power Costs

	NSP	**MN Allocator**	**MN**
Case 1		77.30%	
Case 2		77.30%	
Case 3		77.30%	
Pulled Forward		77.30%	

Unit 1 Less 2029 Replacement Power Costs

	Case 1	Case 2	Case 3
Pulled Forward			
Industry-median performance			

Unit 2 2029 Avoided Replacement Power Costs

	NSP	**MN Allocator**	**MN**
Case 1		77.30%	
Case 2		77.30%	
Case 3		77.30%	
Pulled Forward		77.30%	

Unit 2 Less 2029 Replacement Power Costs

	Case 1	Case 2	Case 3
Pulled Forward			
Industry-median performance			

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NEI data
Calculation 2018 to end of outage

Prairie Island 1	Bottom Quartile	Median Quartile	Top Quartile
operating hours	51,229	51,229	51,229
actual outage hours	232	232	232
cable failure outage hours	2,463	2,463	2,463
Industry performance %	7%	3%	1.0%
Industry outage hours	3,586	1,537	512
outage hours above industry	-891	1,158	2,182
compared to Industry	-36.2%	47.0%	88.6%

Prairie Island 2	Bottom Quartile	Median Quartile	Top Quartile
operating hours	52,371	52,371	52,371
actual outage hours	463	463	463
cable failure outage hours	2,438	2,438	2,438
Industry performance %	7%	3%	1.0%
Industry outage hours	3,666	1,571	524
outage hours above industry	-765	1,330	2,377
compared to Industry	-31.4%	54.5%	97.5%

Combined	Bottom Quartile	Median Quartile	Top Quartile
compared to Industry	-33.8%	50.8%	93.1%