Direct Testimony and Schedules
Allen D. Krug

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___(ADK-1)

Policy

June 30, 2025

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Schedules

Terms and Acronyms

A&G	Administrative and General (costs)
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used During Construction (the cost of financing during the period a capital investment is constructed)
AIP	Annual Incentive Program
AMI	Advance Metering Infrastructure (as in metering)
AMP(s)	Aging Management Program(s)
AMR	Automated Meter Reading
ARL	average remaining life
BES(S)	Bulk Energy Storage Systems
C&I	Commercial and Industrial (in, generally, demand billing context)
CAAM	Cost Assignment and Allocation Manual
CAPM	The Capital Asset Pricing Model is an analysis based on both current and forecasted interest rates and a forward-looking market risk premium
Cash Working Capital	The net cash requirements needed to provide day-to-day utility service
CBOE	Chicago Board Options Exchange
CC	combined cycle (turbine)
CCOSS	Class Cost of Service Study
CCR	coal combustion residuals
COD	commercial operation date
Commission	South Dakota Public Service Commission
CPI	Consumer Price Index
CT (s)	combustion turbine(s)
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
DCF Model	The Discounted Cash Flow analysis estimates the cost of equity produced by the three different analyses used in calculating a

	ROE recommendation (CAPM, Risk Premium, and Expected Earnings)
DFS	Dry Fuel Storage (for nuclear spent fuel casks)
DI	Distributed Intelligence (as in metering)
DPS	dividends per share
DSM	Demand Side Management
DTA	deferred tax asset
E&S	Engineering and Supervision (costs)
ECC	Energy Charge Credit (a high load factor charging credit)
EnCompass Modeling	EnCompass resource planning model (a capacity expansion tool and model that measures resource needs and cost on a chronological basis; used by the Company since 2020)
EOL	End of Life
EPS	earnings per share
ESG	Environmental Social Governance
EUE	expected unserved energy
Expected Earnings Model	The Expected Earnings analysis approach is based on projected returns on book equity that investors expect to receive over the next three-to-five years
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
FPIP	Feeder Performance Improvement Plan (as in substation equipment)
GDP	Gross Domestic Product
GIS	Geographic Information System
GSAM	Goldman Sachs Asset Management
HPS	high-pressure sodium (as in lighting fixtures)
IA	independent auditor (for the Company, Guidehouse)
IRA	Inflation Reduction Act of 2022
IRC	Investment Review Committee (internal)
IRP	Integrated Resource Plan

ISFSI	Independent Spent Fuel Storage Installation
IT	Information Technology
ITC	Income Tax Credit
JCOSS	Jurisdictional Cost of Service Study
K&M	known and measurable (generally in the context of future capital investments or O&M expenses)
King	Allen S. King Generating Plant
KPI	Key Performance Indicators
kVa	kilo Volt amperage
kW	kilowatts
kWh	kilowatt hour
LCOE	Levelized Cost of Energy
Lead / Lag study	A detailed analysis of the time periods involved in a utility's receipt and disbursements of funds (or revenue lag days and expense lead days)
LED	light emitting diode (as in lighting fixtures)
LOLH	loss of load hours
LTI	Long-Term Incentive Program
MACRS	Modified Accelerated Cost Recovery System (tax depreciation system of accounting)
MCM	circular mill (a unit of measurement used to describe the size of electrical wires)
MISO	Midcontinent Independent System Operator, Inc.
MISO Y-2 Retirement Study	Preliminary retirement studies from MISO, which assessed various single Unit and combined Unit retirement scenarios
Monticello	Monticello Nuclear Generating Plant
Moody's	Moody's Investors Service
MPUC	Minnesota Public Utilities Commission
MRP	Market Risk Premium
MW	megawatts
MWh	megawatt hours

NARUC Manual	NARUC's Electric Utility Cost Allocation Manual
NARUC	National Association of Regulatory Commissioners
NASDAQ	The Nasdaq Stock Market LLC
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NOL(s)	Net Operating Loss(es)
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NSPM	Northern States Power Company-Minnesota
NSPW	Northern States Power Company-Wisconsin
O&M	operations and maintenance
OPEBs	Post-Retirement Medical Benefits
PIIC	Prairie Island Indian Community
PPA	Purchase Power Agreement
Prairie Island	Prairie Island Nuclear Generating Plant (Units 1 and 2)
pro forma ("PF") year	The test year for determining rates; for this case, calendar year 2024
PTCs	Production Tax Credits
PVRR	Present Value of Revenue Requirements
PVSC	Present Value of Societal Costs (includes costs for carbon dioxide and other emissions)
rate base	Rate base primarily reflects the costs of capital additions made by a utility to secure plant, equipment, materials, supplies, and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital, as calculated based on the pro forma year
RDF	Refuse Derived Fuel
RECB	MISO's Regional Expansion Criteria and Benefits (working group)
RFP	Request for Proposals

Rider	Infrastructure Recovery Rider, TCR Rider, DSM Rider, and Fuel Cost Rider (FCR)
RIIA	MISO Renewable Integration Impact Analysis
Risk Premium Model	The Risk Premium analysis approach calculates the risk premium as the spread between authorized ROEs for vertically-integrated electric utilities and Treasury bond yields
ROE	Return on Equity
ROR	Rate of Return
S&P	S&P Global Ratings
SAIDI	System Average Interruption Duration Index (for tracking distribution system reliability performance)
SAIFI	System Average Interruption Frequency Index (for tracking distribution system reliability performance)
SCADA	Supervisory Control and Data Acquisition
Sherco	Sherburne County Generating Station or Sherco Station (including Sherco (Units) 1, 2, and 3) (also on site or nearby are Sherco Solar 1, 2, and 3)
SLR	Subsequent License Renewal (from the Nuclear Regulatory Commission)
SMMPA	Southern Minnesota Municipal Power Agency
Strategist Modeling	Strategist resource planning model (a load-duration model used by the Company until 2020)
TCJA	Tax Cuts and Jobs Act of 2017
TCR	Transmission Cost Recovery Rider
TD&G	Transmission, Distribution, and General
test year	for this case, calendar year 2024
the Company	Northern States Power Company or NSP or Xcel Energy
TOD	Time of Day (as in service energy charging)
USGDPIPD	U.S. Gross Domestic Product: Implicit Price Deflator
VIX	Volatility Index
WACC	Weighted Average Cost of Capital

XES or XEI	Xcel Energy Services Inc. (or the Service Company)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Allen D. Krug. I am Associate Vice President, State Regulatory Policy for Northern States Power Company – Minnesota (NSPM or Xcel Energy or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since 1998, initially as a Manager of Renewable Energy and Energy Contract Coordinator. I then served as a Regulatory Consultant for a number of years before becoming Regional Vice President, Regulatory Administration in 2008. I began my current position in 2013. Prior to joining the Company, I worked for over a decade at the Minnesota Department of Commerce, first as a Statistical Analyst and later as a Supervisor in the Electric Regulatory Unit. My statement of qualifications is provided as Exhibit___(ADK-1), Schedule 1.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I develop regulatory strategy for NSP across South Dakota, North Dakota, and Minnesota.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy.

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

A. I am presenting the Company's overall rate case to the Commission. My testimony provides an overview of our application, summarizes the need for a general electric rate increase, explains key developments and initiatives since the Company's last South Dakota rate case, and introduces the Company-sponsored witnesses.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. I present my testimony in the following sections:

- Case Overview;
- Key Developments and Investments in Serving Our South Dakota Customers;
- Rate Case Components;
- Proposed Changes to Rate Recovery;
- Proposed Change for Payments Made Using Credit and Debit Cards;
- Insurance Cost Increases;
- Introduction of Company Witnesses; and,
- Conclusion

Q. ARE THERE ANY OTHER COMPONENTS OF THE COMPANY'S FILING THAT YOU WOULD LIKE TO HIGHLIGHT?

A. Yes. We are filing testimony, exhibits, and work papers in support of our request. In addition, we reviewed all South Dakota Public Utilities Commission Rules and Orders from previous electric rate cases and other dockets to ensure we have complied with the Commission's requirements. My Exhibit___ (ADK-1), Schedule 2, lists the relevant Commission directives and the location in our rate case application of the Company's response.

II. CASE OVERVIEW

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST IN THIS PROCEEDING.

A. In this case, Xcel Energy seeks authority from the Commission to increase our electric retail revenues by approximately $43.6 million, or 15.0 percent. The increase reflects a $63.4 million revenue requirement increase through base rates, offset by the elimination of $19.8 million in Infrastructure Rider and Transmission Cost Recovery Rider (TCR) charges. We base this request on a 2024 historic test year as provided for by South Dakota law. The test year revenue requirement reflects a Return on Equity (ROE) of 10.30 percent and an overall Rate of Return (ROR) of 7.56 percent. Under our proposal, an average residential customer using 756 kWh per month would see an average monthly bill increase of about $20.56 per month or 18.66 percent.

Q. WHAT SIGNIFICANT CHANGES HAS THE COMPANY MADE SINCE ITS LAST RATE CASE?

A. The Company last set base rates in its 2022 rate application (using a 2021 test year) in Docket No. EL22-017. At that time, I explained that the Company was focusing investments on addressing our changing customer demands and an evolving business environment for utilities. Key investments made since then include investments in our distribution grid including new meters and additions made in response to growth in the Sioux Falls area, investments in our generation fleet, general and intangible capital investments such as service center projects and information technology acquisitions, and investments in transmission lines.

Q. WHY IS THE COMPANY SEEKING A RATE INCREASE AT THIS TIME?

A. From 2022 to 2024, we have made approximately $4.4 billion in capital additions on a total Company basis, other than distribution which is generally direct assigned. There are also $1.4 billion (total Company) in known and measurable additions in 2025 and 2026. These investments allow us to serve growing customer demands, will improve the reliability and resilience of our system, and contribute to a diverse mix of generation that benefits our customers.

The Commission has allowed for additional rider revenue, including for investments contemplated in the settlement of the prior rate case. However, not all capital additions can be included in riders, and it is the cumulative impact of capital investments, including those that will be put into service in 2025 and 2026, that is largely driving the Company's need for a general rate case at this time. The requested change in the Company's ROE is also significant and is appropriate given current economic conditions.

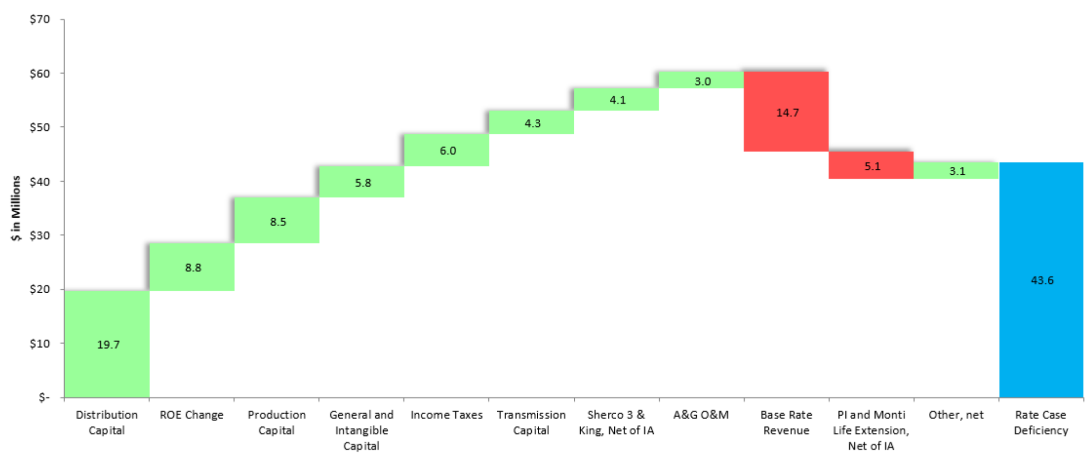
Q. ARE OPERATIONS AND MAINTENANCE (O&M) EXPENSES CONTRIBUTING TO THE NEED FOR THIS RATE CASE?

A. The Company has faced increased O&M cost pressures in some areas, which is not surprising given inflationary pressure on the costs of goods and labor since the Company's 2022 filing. However, the rate impact of the increases in these areas is relatively limited when compared to the impact of the capital the Company is investing to serve its customers, and it is more than offset by increased revenues and other factors. Accordingly, while there are relevant O&M issues, like the increases to insurance premiums I discuss below in Section VII, at its core, this case is largely about the Company's capital investments.

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED TEST YEAR?

A. The Company's request is based on a 2024 historical test year, adjusted for known and measurable changes over a 24-month period as allowed by Commission rules. Figure 1, below, identifies the various categories of costs driving our current revenue deficiency when compared to currently approved rates.

Figure 1
Incremental Drivers: Rate Case Deficiency

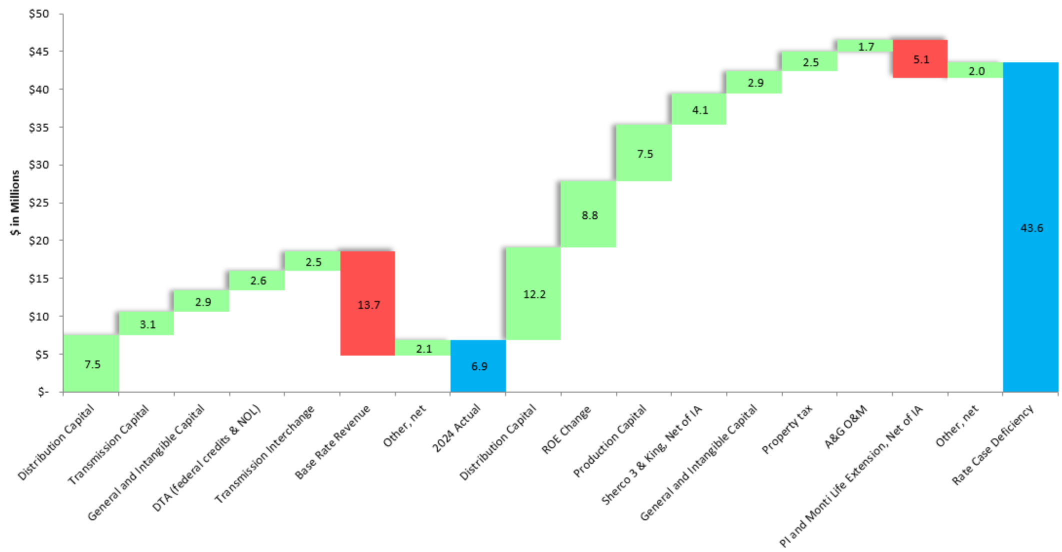


As can be seen in Figure 1, there is no single cost element driving this rate case. Instead, the revenue deficiency is the result of multiple factors, including investments made to build out and improve our South Dakota distribution system, investments in our electric generation (or production) facilities, general and intangible investments (largely consisting of information technology, fleet, and property services projects), and investments in the transmission system.

Figure 2 below offers another view in which forward-looking rate case drivers are separated from the impacts of completed capital additions. Both Figure 1 and Figure 2 provide a net view of the case; accordingly, the TCR and

Infrastructure riders and the projects for which they provide recovery are netted against each other.

Figure 2
Incremental Drivers: Rate Case Deficiency



Q. WHAT DOES FIGURE 2 SHOW?

A. Figure 2 highlights the relative significance of the known and measurable capital addition revenue requirements. It also shows the impacts of ROE and taxes. Finally, it shows the material offsetting effect of extending the lives of the Company's Monticello and Prairie Island nuclear generation plants.

III. KEY DEVELOPMENTS AND INVESTMENTS IN SERVING OUR SOUTH DAKOTA CUSTOMERS

Q. PLEASE DESCRIBE THE COMPANY.

A. Xcel Energy serves more than 1.5 million electricity customers in South Dakota, North Dakota, and Minnesota. The Company is part of an integrated system of generation and transmission that serves the upper Midwest, including Xcel

Energy's operations in Wisconsin and Michigan served by NSP-Wisconsin (collectively, the NSP System). Our combined system operations include 29 Company-owned power plants, more than 121,000 conductor miles of transmission and distribution lines, and approximately 354 transmission and distribution substations. Statement Q, which I sponsor, provides additional information regarding the Company's utility operations.

Q. HOW DOES XCEL ENERGY'S INTEGRATED SYSTEM HELP TO MEET ITS CUSTOMERS' NEEDS?

A. Our integrated NSP System helps to provide cost-effective, reliable, and safe service to all our customers in the Upper Midwest, including those in South Dakota. Our customers across the five states in our Midwest service area derive benefits from an integrated system and a comprehensive approach to planning for and meeting customers' needs. The diversity of our energy supply supports our customers by reducing the risk of significant increases in customer bills due to cost, regulatory, or supply issues that can occur for any one energy source. Our customers also benefit by the fact that many significant business costs can be spread over a larger base, thus lowering the average cost of service.

Q. WHEN WAS THE COMPANY'S LAST RATE CASE, AND WHAT TEST YEAR IS THE BASIS OF THE COMPANY'S CURRENT RATES?

A. The Company filed its last rate case in Docket No. EL22-017 in June 2022 using a 2021 historic test year. The 2021 Cost of Service is the baseline for our current base rate structure.

Q. WHAT WAS THE OUTCOME OF THE LAST RATE CASE?

A. Pursuant to the Settlement Stipulation approved by the Commission, the Company increased rates by approximately 1.5 percent (on a net basis). However, the Settlement Stipulation also included provisions regarding the use of the Infrastructure Rider for investments that the Company had presented as known and measurable additions in the rate case.

Q. WHAT LEVEL OF CAPITAL INVESTMENTS HAS THE COMPANY MADE SINCE 2021?

A. Xcel Energy has made approximately $4.3 billion on a total Company basis in generation, transmission and common investments from 2022 to 2024 to provide safe, reliable, and affordable electricity to our customers. The Company has also made $0.1 billion in distribution investments during that same period in South Dakota.

Q. WHAT WERE THOSE INVESTMENTS?

A. As can be seen in Figure 1 above, significant capital investments have been and will be made to the Company's distribution system in South Dakota. This includes a new substation, the installation of new advanced meters for all of our customers, and investments to improve the reliability and resilience of the system. The Company has also made a wide variety of other investments across our system to provide reliable, safe, and cost-effective service to our customers. In particular, we made investments in production assets, including wind farms, solar installations, and projects at our nuclear generation facilities, including those related to extending their service lives, and in the transmission system.

Q. CAN YOU DESCRIBE THE DISTRIBUTION SYSTEM INVESTMENTS IN GREATER DETAIL?

A. Yes. These investments include the new Great Plains substation on the west side of Sioux Falls, the addition of a second transformer and related feeder installation at the Lousie substation in Sioux Falls, the installation of the new, advanced meters, work done in response to extreme weather, the replacement of a feeder in Sioux Falls, the relocation of infrastructure in response to public works projects, including the widening of Highway 34 between Fedora and Artesian, the addition of feeder load monitoring equipment at substations, projects adding infrastructure to serve new customers, and investments to improve the reliability and resilience of the system, including replacement of utility poles and underground cable.

Q. ARE THERE SPECIFIC FACTORS CONTRIBUTING TO THE NEED FOR SO MUCH DISTRIBUTION SYSTEM INVESTMENT?

A. The Company has to continuously invest in the distribution system to maintain reliability and resiliency, and so every rate case will include distribution system investments. However, there are a few factors contributing to the significance of distribution capital investments in this case. These include the timing of the investment in new meters, which are replacing meters the Company had been using since the 1990s. The meter replacement is necessary because the manufacturer of our legacy meters stopped making replacement parts after 2022, and our meter reading contract for the legacy meters expires at the close of this year. Severe weather, particularly in 2022, was also a meaningful factor contributing to the need for distribution system investment. It should also be noted that the costs of distribution system components have increased. Growth in the Sioux Falls area has also been material. It led to investments to connect new customers to the system and investments in increasing the capacity of the distribution system in response to increased load. The overall costs of our distribution system investments outstrip the revenues from new business. In his Direct Testimony, Company witness Brandon T. Cramer provides a more detailed discussion of the distribution system investments.

Q. PLEASE DISCUSS THE INVESTMENTS IN THE NUCLEAR FLEET.

A. As Company witness Bixuan Sun explains in her Direct Testimony, the Company made the decision to seek to extend the operating lives of both of its nuclear generation facilities. The Monticello Nuclear Generation Plant has already been granted a Subsequent License Renewal (SLR) from the Nuclear Regulatory Commission extending its license period so that it can be operated through 2050. The Company is planning to file an SLR application for the Prairie Island Nuclear Generation Plant by the end of 2026, which, if granted, would allow Prairie Island Units 1 and 2 to operate through 2053 and 2054, respectively. Some of the key nuclear investments in this case are related to extending the lives of those facilities, including expanding on-site dry cask storage for spent nuclear fuel. Other key investments include reliability improvement projects including baffle bolt and clevis bolt replacement projects at Prairie Island Unit 2, and groundwater monitoring, hardening, and mitigation projects at both Prairie Island and Monticello.

Q. PLEASE DISCUSS THE IMPORTANCE OF THE NUCLEAR GENERATION FLEET.

A. Prairie Island and Monticello are key assets within the Company's overall generation asset portfolio. They are reliable sources of baseload power which provide almost 30 percent of the NSP System's electricity. They also provide a hedge against changes in resource availability, increases in fossil fuel prices, and emissions regulations that may be enacted in the future.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN WIND AND SOLAR GENERATION.

A. In her Direct Testimony, Company witness Sun discusses the Sherco Solar 1, 2, and 3 projects in greater detail; however, I will briefly describe them. These are grid-scale solar resources that have a collective nameplate capacity of 460 MW. They are being added to the system to address a capacity need that was earlier identified as arising in the mid-2020s. The projects benefit from the ability to use existing transmission infrastructure and interconnection rights at the site of the Sherburne County Generation Station (Sherco). There are also wind farms that have come into service, which were subject to cost recovery under the Infrastructure Rider, but which the Company is now seeking to roll into base rates.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENTS IN TRANSMISSION PROJECTS.

A. To meet the growing need for transmission in the region, the Company made capital additions totaling $729.7 million in transmission assets between 2022 and 2024. Much of this work involved asset renewal and reliability investments, including line rebuild projects, and communication infrastructure projects. Company witness Michele A. Kietzman discusses transmission investments further in her Direct Testimony.

Q. ARE THERE OTHER KEY ISSUES THAT YOU WISH TO DISCUSS?

A. Yes. In Figure 1 and Figure 2 above, Sherco Unit 3 and the Allen S. King Plant (King) are shown as drivers for the case. This represents the Company's proposed change in the depreciation rates for these facilities in light of the planned retirements in 2028 (King) and 2030 (Sherco 3) for these two coal-fired generation facilities. Company witness Sun discusses the reasons for these retirement decisions, and Company witness Kietzman provides the proposed change in depreciation.

Q. WAS THIS ISSUE ADDRESSED IN THE SETTLEMENT OF THE PRIOR RATE CASE?

A. Yes. In the Settlement Stipulation that the Commission approved, the parties agreed to keep the depreciation lives and rates for the two plants unchanged; however, there was no determination made regarding the reasonableness of the retirements, and the Company's ability to request a change in the lives and depreciation rates for the King and Sherco 3 was explicitly recognized. The Company is now exercising that right.

Q. HOW DO THE PROPOSED CHANGES IN DEPRECIATION FOR THESE FACILITIES COMPARE TO THOSE FOR THE NUCLEAR FACILITIES?

A. While the Company is seeking to increase depreciation for Sherco 3 and King given the planned retirement dates, it is also simultaneously seeking to decrease depreciation for the nuclear fleet given the decisions made to extend the lives of those facilities by 20 years. The proposed reductions for Monticello and Prairie Island more than offset the proposed increase in depreciation for Sherco 3 and King.

Q. IS THE COMPANY SEEKING A DECISION FROM THE COMMISSION WITH REGARD TO THE RESOURCE PLANNING DECISIONS RELATED TO THE SHERCO 3 AND KING RETIREMENTS?

A. No. The Company is only seeking approval to adjust the depreciation rates consistent with the retirement dates. It is not seeking Commission approval with regard to broader issues of resource planning, including the selection of new resources, which will be addressed in the decisions the Commission makes in future proceedings.

IV. RATE CASE COMPONENTS

A. Test Year

Q. WHAT TEST YEAR DOES THE COMPANY PROPOSE IN THIS CASE?

A. The test year is 2024, adjusted to properly reflect regulatory requirements and account for appropriate known and measurable changes. As discussed by Company witness Laurie J. Wold in her Direct Testimony, we include $30.9 million on a revenue requirements basis of incremental known and measurable changes for 24 months consistent with the Commission's rules. These incremental known and measurable changes include projects that have been and will be placed in service in 2025 or 2026. It also includes other additional known and measurable operating expenses items such as property taxes and wages as well as increased insurance costs.

B. Rate of Return

Q. WHAT RATES OF RETURN IS THE COMPANY PROPOSING IN THIS APPLICATION?

A. Our proposed revenue requirement reflects an overall rate of return on investment of 7.56 percent, based on an average common equity ratio of 52.87

percent and an ROE of 10.30 percent. Company witness Joshua C. Nowak provides a detailed analysis of the appropriate overall ROR and ROE for the Company.

Q. DO YOU HAVE ANY POINTS YOU WOULD LIKE TO RAISE WITH REGARD TO ROE IN YOUR TESTIMONY?

A. Yes. I would like to emphasize the practical importance of setting an appropriate ROE and the relevance of current market conditions. An ROE within the correct range provides the right level of incentive for investment in South Dakota, neither too high or too low, and avoids a possible impact on the Company's credit rating that can occur if rating agencies perceive that NSP operates in difficult regulatory environments.

Q. WHAT ARE THE CURRENT CONDITIONS YOU REFERENCED?

A. I am referring to volatility in the financial markets and general economic uncertainty, including that related to tariffs and international trade. Equity investors expect higher returns during uncertain times. However, in order to moderate rate impacts on customers and be consistent with recent requests it made in other jurisdictions, the Company is requesting an ROE that is at the low end of the range indicated by Company witness Nowak's analyses.

C. Revenue Requirements

Q. WHAT BASE RATE REVENUE REQUIREMENT IS THE COMPANY PROPOSING IN THIS RATE CASE?

A. The Company is proposing a revenue requirement of $333.2 million, which is an overall base rate increase of $63.4 million, offset by the elimination of $19.8 million from the Infrastructure and TCR Riders. When the reduction of rider revenue is netted with the Company's request, the overall revenue deficiency sought in this rate case is $43.6 million or 15.0 percent.

D. Rate Design

Q. PLEASE DESCRIBE YOUR PROPOSED RATE DESIGN FOR THIS CASE.

A. We are not proposing any material changes to the current rate design. We are proposing a change to the customer charge structure for Residential and Small Commercial customers due to the new AMI meters the Company has been rolling about across our service territory. Company witness Nicholas N. Paluck discusses this further and identifies the minor proposed rate design changes.

V. PROPOSED CHANGES TO RATE RECOVERY

A. Incentive Pay

Q. IS THE COMPANY SEEKING TO MAKE ANY CHANGES TO RATE RECOVERY ASSOCIATED WITH HUMAN RESOURCES AND EMPLOYEE COMPENSATION?

A. Yes, we are seeking to adjust the extent to which two forms of incentive pay are considered in determining base rates in South Dakota. The two incentive programs are: 1) the Annual Incentive Program (AIP) and 2) the Long-Term Incentive program (LTI).

Q WHAT IS AIP AND WHY IS IT IMPORTANT?

A. AIP is an important component of compensation for Xcel Energy's exempt, non-bargaining employees. All exempt, non-bargaining employees are eligible to receive AIP. Those eligible employees each have a targeted annual incentive, expressed as a percentage of base pay, and they can earn those incentives through achievement of individual performance goals and by the Company's achievement of corporate Key Performance Indicators.

AIP serves several critical functions for the Company. By paying employees based on performance, the Company provides additional motivation for individual employee performance. Also, AIP brings the Company's employee compensation in line with market levels. On the latter point, Xcel Energy is aware that its peer local and national investor-owned utilities also have incentive pay programs. Without AIP, Xcel Energy's compensation program would not be in line with competitors, and it would find it more difficult to attract and retain exempt, non-bargaining employees.

Like any employer, Xcel Energy has always had to compete in the labor market for quality employees, and customers benefit when the appropriate employees are operating the electrical generation, distribution, and transmission systems. The Company competes in the labor market with both other utilities and, for many positions, public and private employers in a variety of industries. It is important that the Company maintain a competitive compensation package.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR HOW AIP SHOULD BE ADDRESSED IN THIS RATE CASE?

A. The Company is proposing that it be allowed to recover AIP expenses up to 20 percent of base pay consistent with the prior settlement. Company witness Wold discusses the impacts on the rate case of this proposal.

Q. WHAT IS LTI?

A. LTI is an incentive program that is available to a smaller set of employees than AIP. While AIP is available to all exempt, non-bargaining employees, less than five percent of exempt and non-bargaining employees are eligible for LTI. The employees who receive an LTI grant tend to be those who have a higher level of influence in the Company's direction and strategy, and also are employees who are in positions that can be expensive and time-consuming to fill. The LTI program helps retain these key employees and, like AIP, is necessary for Xcel Energy to remain competitive in the labor market.

Q WHAT COMPONENTS GO INTO LTI?

A. Three components comprise the LTI program: 1) environmental performance LTI, 2) total shareholder return LTI, and 3) time-based LTI. However, the Company is only seeking recovery for the environmental and time-based LTI costs. The Company is not seeking to have the shareholder return component recovered through customer rates.

Q. WHAT IS ENVIRONMENTAL LTI?

A. Environmental LTI is the portion of the LTI program tied into the achievement of the Company's carbon emission reduction goals. Debt and equity investors have been interested in Environmental, Social, and Governance (ESG) factors, and progress towards Xcel Energy's stated environmental goals has an impact on ESG evaluations. Environmental LTI provides an incentive for key employees to help meet those goals.

Q. WHAT IS TIME-BASED LTI?

A. The time-based LTI is used to attract, retain, and motivate eligible employees. It helps ensure that those employees engage in long-term planning for the benefit of the Company and that they remain with Xcel Energy long enough to implement those long-term plans. In order to accomplish those goals, there is a three-year vesting period for the time-based LTI payment.

Q. WHAT IS THE COMPANY'S PROPOSAL FOR HOW LTI SHOULD BE ADDRESSED IN THIS RATE CASE?

A. The Company is proposing that it be allowed to recover the environmental and time-based portion of its LTI expenses. The recovery of time-based LTI expenses would not be an adjustment, as that was allowed by the Commission-approved settlement that resolved the prior rate case; however, recovery of the environmental-based portion of LTI would. Company witness Wold discusses the impacts on the rate case of allowing for rate recovery of LTI.

B. Prairie Island Indian Community Payments

Q. WHAT IS THE PRAIRIE ISLAND INDIAN COMMUNITY (PIIC)?

A. PIIC is a federally recognized Indian tribe whose community is immediately adjacent to the Prairie Island Nuclear Generating Plant. In fact, PIIC is the closest community to a nuclear facility in the United States. Given that proximity, PIIC is impacted by the Company's plan to extend the life of the plant and had rights and concerns that needed to be addressed in connection with that plan.

Q. HOW IS THE COMPANY ADDRESSING PIIC'S RIGHTS AND CONCERNS WITH A LIFE EXTENSION OF THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT?

A. Pursuant to a 2023 amended settlement with PIIC, the Company is paying the community $7.5 million per year plus an additional $50,000 per cask of fuel stored at the site. These amounts are in addition to $2.5 million per year that was already due to PIIC under a prior version of the settlement. The settlement was entered into after extensive discussions with PIIC and was an important step towards securing approval for extending the operating life of the plant. The settlement was also approved by the Minnesota legislature.

Q. HAVE SOUTH DAKOTA CUSTOMERS BEEN CONTRIBUTING TO THE COST OF THOSE $2.5 MILLION ANNUAL PAYMENTS?

A. No. Those costs have been paid only by Minnesota customers.

Q. WHY DOES THE COMPANY BELIEVE SOUTH DAKOTA CUSTOMERS SHOULD PAY A JURISDICTIONAL SHARE OF THIS NEWER SETTLEMENT?

A. The payment to the PIIC is one of the costs of continuing to operate the nuclear plant. Our customers in South Dakota will benefit from extending the lives of our nuclear generation facilities, which are a reliable source of base load generation, and so they should pay a jurisdictional share of this plant-related cost, just as they do for other expenses of the nuclear fleet. Although it is not a property tax, the amount of the payment to PIIC is similar in the sense that it is a payment to a host community, and customers from all jurisdictions pay their shares of property taxes. Moreover, the Company determined that addressing PIIC's concerns was a necessary step before seeking the governmental approvals to extend the life of the plant.

Q. HAS THE COMMISSION PREVIOUSLY CONSIDERED THE PIIC PAYMENTS?

A. Yes. In Docket No. EL23-025, the Company sought to recover the jurisdictional share of the PIIC payments in the Infrastructure Rider. In an August 2, 2024 Order, the Commission allowed the Company to defer the South Dakota portion of the PIIC payments in a regulatory asset. The Order further provided that it did not preclude future Commission review of the reasonableness of the amounts.

Q. ARE THE AMOUNTS SOUGHT BY THE COMPANY REASONABLE?

A. Yes. The amounts paid to PIIC are reasonable. It is normal to compensate the governments of host communities, and the negotiated settlement will facilitate the Company's efforts to extend the life of the plant, which will benefit South Dakota customers as described in the testimony of Company witness Sun. The amount of the settlement payments was arrived at following extensive negotiations with the PIIC tribal council.

Q. WHAT IS THE COMPANY SEEKING IN THIS RATE CASE?

A. The Company is seeking to amortize the amount in the regulatory asset over a three-year period and to include the annual payment amount in its cost of service. Company witness Wold addresses the impact of this recovery in her Direct Testimony.

Q. WHY IS THE COMPANY SEEKING TO RECOVER THE AMOUNTS IN THE REGULATORY ASSET NOW?

A. While the Commission's Order in Docket No. EL23-025 referenced eventual recovery once the plant had either been granted or denied a life extension, the Company is seeking to recover the amount in the regulatory asset now and include the annual cost of the payments in its cost of service because it is also including the proposed reductions in depreciation and Nuclear Decommissioning Trust expenses arising from the longer life for the Prairie Island plant in this case. Because the Company is seeking to include the benefits from the life extension in rates, it also is appropriate to include the costs of the life extension—including these necessary payments.

VI. PROPOSED CHANGE FOR PAYMENTS MADE USING CREDIT AND DEBIT CARDS

Q. HOW DOES THE COMPANY CURRENTLY HANDLE BILL PAYMENTS MADE USING CREDIT AND DEBIT CARDS?

A. Currently, customers wishing to pay their electric bill with a credit or debit card do so through a third-party vendor, with each transaction subject to a $1.80 processing fee paid by the customer to the third-party vendor. Such fees are a result of the processing charges levied by credit card networks such as MasterCard, Visa, Discover, and American Express to merchants accepting credit card payments from their customers.

Q. HOW DOES THAT COMPARE TO CUSTOMER EXPECTATIONS?

A. Across multiple industries, and in day-to-day transactions such as purchasing groceries, credit card fees are invisible to the customer as the merchant typically incorporates this cost into their pricing and does not require the customer to make separate payment of the processing fee.

Q. ARE THERE ADVANTAGES TO CREDIT AND DEBIT CARD PAYMENTS?

A. Yes. As I noted above, customers are accustomed to using credit and debit cards for a variety of types of payments. In addition, many customers appreciate the convenience of making payments using debit and/or credit cards.

Q. WHAT IS THE COMPANY PROPOSING?

A. The Company is proposing that it waive the fee for credit and debit card processing, including for both one-time and autopay payments. Waiving this fee would align the experience of our customers' electric bill payment transactions with that of countless other transactions made across the state each day. The credit card networks' processing charges would become socialized as O&M expenses. As discussed by Company witness Wold, we are proposing to establish a baseline amount of credit card fees for the South Dakota jurisdiction in rates and track actual South Dakota costs above or below that baseline for recovery or return to customers in a future rate case.

Q. WHEN IS THE COMPANY PROPOSING TO IMPLEMENT THIS CHANGE?

A. The Company is proposing to begin waiving fees for credit card and debit card payments following Commission approval, but no sooner than 2026.

Q. HOW IS THE COMPANY PROPOSING TO IMPLEMENT THIS CHANGE?

A. Assuming the program is approved, the Company intends to open participation to customers via a "soft launch," that is, without direct marketing or formal announcement. Using a soft launch approach will allow for better control around initial interest in participation and avoid a situation where utilization of the product exceeds estimated levels, thereby increasing the cost of the program. In addition, a soft launch saves the Company and customers any marketing costs that would be otherwise incurred.

Q. DID THE COMPANY MAKE A SIMILAR PROPOSAL IN THE PRIOR RATE CASE?

A. Yes. However, the stipulation that resolved that case did not include approval for this change.

Q. WHY IS THE COMPANY RAISING THE ISSUE AGAIN IN THIS MATTER?

A. The Company continues to believe that this change is appropriate. Our customers continue to expect to be able to pay with debit or credit cards without incurring an additional fee.

Q. WHAT IS THE ESTIMATED COST OF THIS PROPOSED CHANGE?

A. The Company is conservatively estimating an annual cost of approximately $0.50 million and proposes to use that as the baseline amount against which actual expenses would be tracked.

VII. INSURANCE COST INCREASES

Q. IS THE COMPANY FACING HIGHER INSURANCE COSTS?

A. Yes. The insurance market is hardening for electric utilities, particularly with regard to liability and conventional property insurance. This is partially a response by insurers to significant damages and liabilities that electric utilities have faced in recent years as a result of catastrophic wildfires.

Q. IS THE COMPANY TAKING STEPS TO ADDRESS WILDFIRE RISK?

A. Yes. The Company is implementing wildfire risk mitigation programming. These efforts will reduce the risk of the Company's infrastructure causing wildfires and are also important in Xcel Energy's negotiations with insurers with regard to coverage and premiums. However, despite those efforts some increase in insurance costs has been unavoidable.

Q. DOES THE COMPANY MAKE EFFORTS TO MANAGE ITS INSURANCE COSTS AND MITIGATE THE EXTENT OF INCREASED PREMIUMS?

A. Yes. The Company makes extensive efforts, working with our insurance brokers, to put together an appropriate insurance package while keeping costs down. This involves exploring different possible coverage options and extensive negotiations with insurers regarding coverage terms and premium amounts. As part of these efforts, the Company provides information to insurers regarding its risk management programs, including those aimed at wildfire risk mitigation.

Q. WHAT IS THE INCREASE THE COMPANY IS SEEKING TO RECOVER?

A. The Company is seeking to recover increased insurance costs of $0.9 million in this rate case. This is a known and measurable change in the Company's cost of providing electric utility service. These insurance costs are based on the increased cost of service in 2024 for certain insurance types and our expectations of further increased costs based on our experience and overall industry trends.

VIII. INTRODUCTION OF COMPANY WITNESSES

Q. WHO ARE THE WITNESSES FOR THE COMPANY IN THIS PROCEEDING?

A. In addition to my Policy Testimony, the Company sponsors the following witnesses:

- *Laurie J. Wold,* who sponsors the overall revenue requirement for the rate case. Company witness Wold sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations.
- *Joshua C. Nowak* of Concentric Energy Advisors, who sponsors testimony on the ROE and ROR including capital structure and cost of capital.
- *Michele A. Kietzman*, who sponsors testimony regarding the Company's material capital additions since the last rate case, depreciation expense and depreciation rates, and nuclear decommissioning accruals.
- *Brandon T. Cramer*, who sponsors testimony regarding the Company's distribution capital additions and O&M expenses.
- *Bixuan Sun,* who sponsors testimony regarding the prudence of the Company's generation resource decisions, including the planned retirement of the King and Sherco 3 generating plants, the extension of the remaining lives of the Monticello and Prairie Island nuclear generating plants, and the addition of the Sherco Solar 1, 2, and 3 projects.
- *Christopher J. Barthol*, who sponsors our class cost of service study.
- *Nicholas N. Paluck*, who sponsors rate design and tariff modifications.

Together, these witnesses provide the information and advocacy needed to evaluate and approve our Application.

IX. CONCLUSION

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST TO THE COMMISSION.

A. We respectfully request that the Commission approve:

- Our requested rates that provide a net incremental revenue requirement increase of $43.6 million;
- An overall ROR on investment of 7.56 percent, based on an average common equity ratio of 52.87 percent and an ROE of 10.30 percent; and
- Minor changes to our rate design.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.