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. EL22-____
Exhibit___(ADK-1)

Policy

June 30, 2022

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Schedules

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 (NSP 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 strategic 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 Investmetns in Serving Our South Dakota Customers;
- Return on Equity;
- Rate Case Components;
- Proposed Changes to Rate Recovery;
- Proposed Change for Payments Made Using Credit and Debit Cards;
- 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, the action the Company has taken to address each directive, 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 $44.1 million, or 17.9 percent. The increase reflects an additional $85.8 million through base rates, offset by the elimination of $41.7 million in Infrastructure and Transmission Cost Recovery Rider (TCR) charges. We base this request on a 2021 historic test year as provided for by South Dakota law. The test year revenue requirement reflects a Return on Equity (ROE) of 10.75 percent and an overall Rate of Return (ROR) of 7.65 percent. Under our proposal, a residential overhead customer using 750 kWh per month would see an average monthly bill increase of about $19.58 per month or 19.75 percent.

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

A. The Company last set base rates in its 2014 rate application (using a 2013 test year) in Docket No. EL 14-058. At the time, the Company was in the midst of an investment cycle in which it was investing in refreshing and upgrading the system. In the policy testimony filed in that case, the Company explained it was then "in a period of elevated system investment." That work included the replacement and refreshing of infrastructure originally built to handle the rapid post-war growth experienced during the 1950s to 1970s. Since the last case, we have completed that system refresh, and while we must always continue to replenish our system so that it continues to provide safe and reliable service, we are now focusing our investments to address our changing customer demands and an evolving business environment for utilities. These investments include modernizing our distribution grid and moving toward a carbon emission free generating fleet.

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

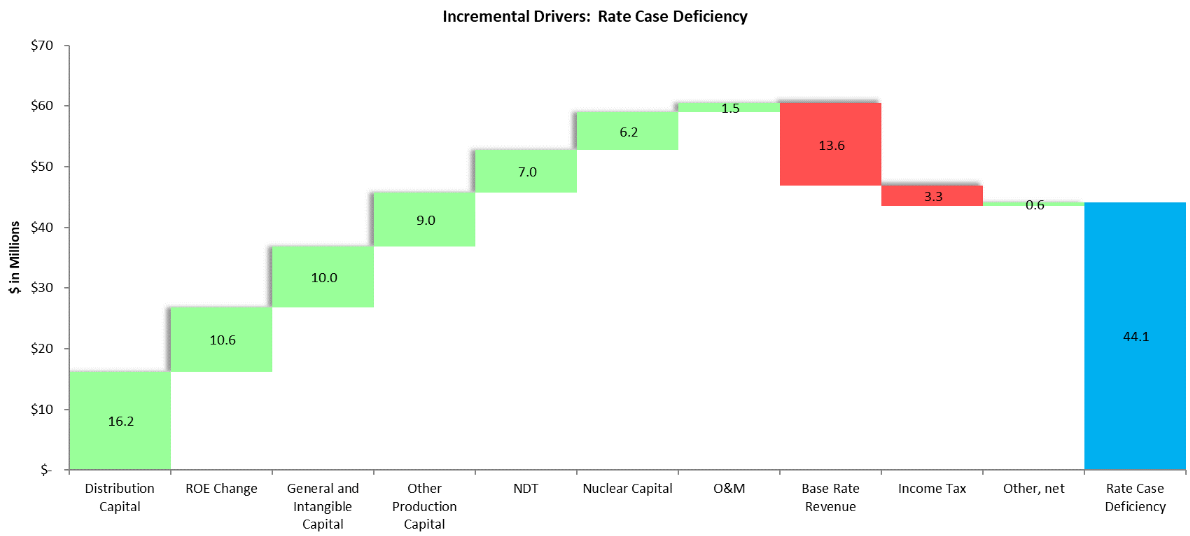
A. From 2014 to 2021, we have made approximately $9.3 billion in capital additions. There are also $1.646 billion in known and measurable additions. As a result of our investments, our system is more robust and reliable, and our customers benefit from a diverse mix of generation. Several significant capital investments, including various wind projects that are keeping fuel costs down, have been approved for inclusion in the Infrastructure Rider or the Transmission Cost Recovery Rider by the Commission.

The Commission's allowance of such additional rider revenue, particularly for new and repowered wind projects, and cost savings from the Tax Cut and Jobs Act (TCJA) has allowed us to manage our system without the need for a general rate case for a number of years. However, not all capital additions can be included in riders, and it is the cumulative impact of these capital investments that is largely driving the Company's need for a general rate case at this time. The requested change in the Company's return on equity is also significant but appropriate to reflect changed economic circumstances.

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

A. The Company's request is based on a 2021 historic 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. As Figure 1 indicates, additional revenue sources have more than kept up with the increasing operation and maintenance costs, and it is the impact of our capital investments and other items that are driving the need for a rate case.

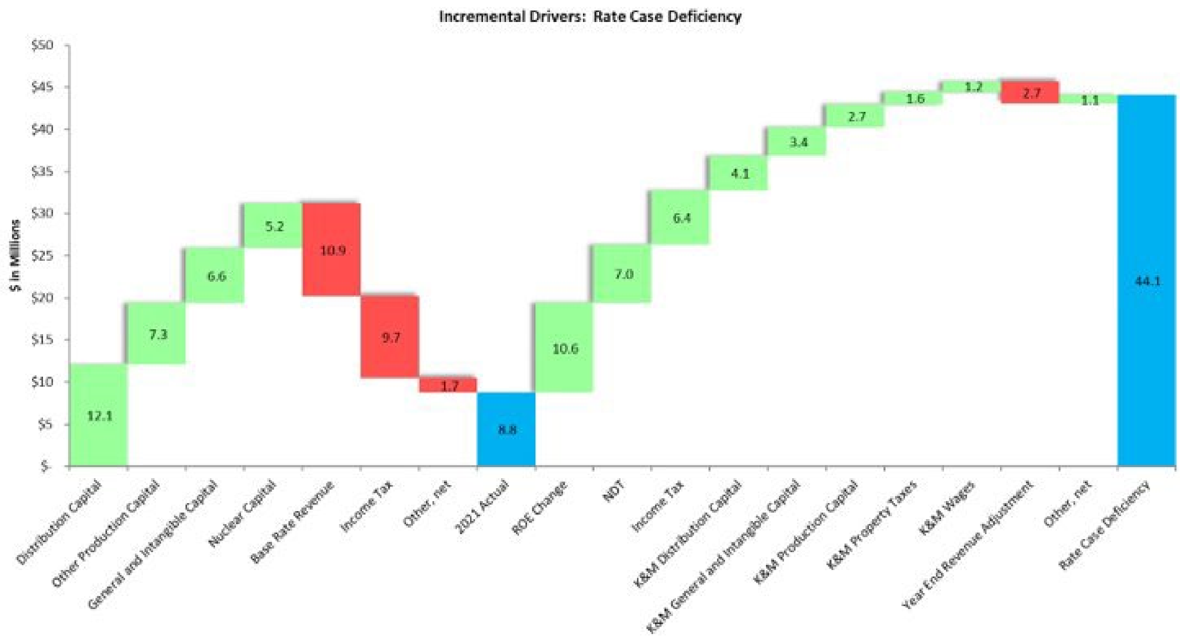
Figure 1



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 support and improve the reliability of our South Dakota distribution system, general and intangible investments (largely consisting of updates to information technology systems), normal annual additions and capital improvements to our non-nuclear generation resources, and investments in the Company's nuclear generation fleet.

Figure 2 below offers another view in which forward-looking rate case drivers are separated out 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



Q. WHAT DOES FIGURE 2 SHOW?

A. Figure 2 shows that while most of the capital additions driving this case were in place by the 2021 test year or recovered in the TCR or Infrastructure riders, there are approximately $10 million in known and measurable capital revenue requirements, which includes portions of the Company's Meter Replacement project. This view also emphasizes the impact of return on equity, taxes, and contributions to the nuclear decommissioning trust to our overall revenue deficiency.

Q. DID THE COMPANY CONSIDER THE IMPACT OF THE COVID-19 PANDEMIC AND CURRENT INFLATION IN ITS DECISION TO FILE THIS CASE?

A. Yes. We recognize that our rate request will impact our customers during a period when other prices are also increasing. However, after approximately eight years, the Company cannot further postpone filing a new general rate case.

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 includes 24 Company-owned power plants, more than 115,561 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 Docket No. EL 14-058 in June 2014 using a 2013 test year. That 2013 test year is now more than eight years old, but the 2013 Cost of Service is still 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 in Case No. El-14-058, the Company increased rates by approximately 3.6 percent. The Settlement Stipulation also included a rate case moratorium.

Q. PLEASE DESCRIBE THAT RATE CASE MORATORIUM.

A. Pursuant to the Settlement in Docket No. EL-14-058, the Company agreed not to file any rate case seeking an increase proposed to be in effect prior to January 1, 2018. Subsequently, in Docket No. GE17-003, which concerned the federal Tax Cut and Jobs Act ("TCJA"), the Company agreed in a Settlement Stipulation approved by the Commission not to file a general rate case prior to June, 2020.

Q. DID THE COMPANY MAKE ANY OTHER RELEVANT COMMITMENTS IN RESOLVING THE TCJA MATTER?

A. Yes. In the Settlement Stipulation resolving the TCJA matter, the Company also agreed to refund approximately $10.87 million to customers for 2018. However, the Company was allowed to retain the TCJA savings for subsequent years. As I noted above, those savings, along with the Commission's approval of the recovery of certain costs via rider, allowed the Company to avoid filing a new general rate case.

Q. WHAT LEVEL OF CAPITAL INVESTMENTS HAS THE COMPANY MADE SINCE 2013?

A. Xcel Energy has made approximately $6.7 billion in NSPM generation and transmission investments from 2014 to 2021 to provide safe, reliable, and affordable electricity to our customers. The Company has also made $151 million 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 made at the Prairie Island and Monticello nuclear plants. 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, initiatives and individual projects in the following additional areas were primary drivers of our capital additions: wind farms, regional expansion transmission projects, a new natural gas combustion turbine, updates to our information technology and business systems, and the Company's Meter Replacement project. In addition, within South Dakota, the Company made capital investments in distribution substations, poles, cables, and other infrastructure as part of the revitalization of the Company's basic infrastructure discussed in the prior rate case. These distribution investments are discussed by Company witness Mr. Marty D. Mensen in his Direct Testimony.

Q. CAN YOU DESCRIBE THE NUCLEAR CAPITAL INVESTMENTS MADE SINCE 2013 IN GREATER DETAIL?

A. Yes. These include improvements required by federal regulators in response to the Fukushima incident; safety, cybersecurity, security, and fire protection improvements; projects undertaken to increase the reliability of the nuclear facilities; the replacement of both main electric generators at Prairie Island; completion of the Monticello life cycle management / extended power uprate project; and the license renewal projects (and associated capital additions) at Prairie Island. Investments in the nuclear fleet in 2020 and 2021 included reloading of nuclear fuel in Prairie Island Unit 1, further security enhancements, replacement of process control equipment, expansion of the dry cask storage at the Prairie Island Independent Spent Fuel Storage Installation, and cooling tower refurbishment. Company Witness Ms. Laurie Wold discusses the nuclear fleet capital investments further in her Direct Testimony.

Q. WHAT HAS BEEN THE RESULT OF THE CAPITAL IMPROVEMENTS OF THE NUCLEAR FACILITIES?

A. The projects we have undertaken at Prairie Island and Monticello since 2013 were critically important, and enabled both plants to operate at 95 percent capacity factor or above in that time. In fact, the Company has never had better reliability at its nuclear fleet, and O&M costs for the two facilities are down. In addition, as a result of the improvements made in response to the Fukushima incident and the other security, fire protection, reliability and safety capital improvements made since the last rate case, the Company's nuclear fleet, which has operated safely since the 1970s, is now even safer, more secure, and more resilient. Prairie Island and Monticello are important sources of low-cost, base load power that are emissions-free, and their continued safe, reliable, and efficient operation are critical to the Company's commitment to provide reliable and reasonably priced electricity to South Dakota consumers while transitioning to cleaner resources.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN WIND GENERATION SINCE THE LAST RATE CASE.

A. In her Direct Testimony, Company Witness Ms. Farah L. Mandich discusses these investments in greater detail; however, I will briefly describe them. To harness the excellent wind resource of South Dakota and neighboring states and turn it into clean power for our customers—at a time when market pricing of new wind generation was historically low—the Company invested $2.9 billion in approximately 2,070 MWs of new and repowered wind facilities from 2014 to 2021. We have been recovering the costs of these facilities through the infrastructure rider and the value of tax credits have gone to our customers through the fuel cost rider. As Ms. Mandich's testimony demonstrates, analyses of these projects continue to demonstrate their prudence, and the Company is seeking to roll them into base rates.

In addition, the Company is also seeking to add to base rates the Grand Meadows Wind Project, a 100.5 MW wind repowering project located in Mower County, Minnesota. The analyses presented in Ms. Mandich's testimony show that the project will create savings for customers under a variety of scenarios.

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

A. To meet the growing need for transmission in the region, the Company made capital additions totaling $2.0 billion in transmission assets, including in regional expansion transmission projects. This includes projects in South Dakota, North Dakota, and Minnesota as part of the CapX2020 initiative. Ms. Wold discusses these projects further in her Direct Testimony.

Q. PLEASE DISCUSS THE COMPANY'S INVESTMENT IN A NEW NATURAL GAS COMBUSTION TURBINE.

A. In 2018, the Company placed into service a new natural gas combustion turbine (Unit 6) at our existing Black Dog generating plant in Minnesota. The Company built the new unit to meet a need in the system, and the choice of natural gas reflects the Company's commitment to a robust mix of generation types.

Q. PLEASE DESCRIBE THE COMPANY'S METER REPLACEMENT AND RELATED INVESTMENTS IN ITS DISTRIBUTION SYSTEM.

A. After more than 20 years, the Company is replacing our Automated Meter Reading (AMR) meters with newer Advanced Metering Infrastructure (AMI) meters and making related investments in monitoring and control systems for the distribution system. The meter replacement project is necessary because the manufacturer of our legacy meters will no longer manufacture replacement parts after 2022, and our AMR meter reading contract expires at the close of 2025. Given the need for new meters, the Company decided to invest in advanced metering technology and pair that with related and supporting investments. These investments will help the Company improve our operation of the distribution grid and also provide more tools and options for customers. Mr. Mensen provides more detail on the specific technologies and proposed uses of the capabilities of the new meters in his Direct Testimony.

Q. HAVE THERE BEEN OTHER KEY CHANGES SINCE THE LAST RATE CASE?

A. Yes. Two other significant impacts to our cost of service are the need to update our depreciation expense and, in particular, to further fund our nuclear decommissioning trust. With regard to depreciation, the Company is updating the retirement dates for the Allen S. King Generating Plant (King) and

Sherburne County Generating Station Unit 3 (Sherco 3) to 2028 and 2030, respectively. These dates have been moved forward consistent with the Company's strategy for reducing carbon emissions and making an eventual transition to carbon-free generation. Ms. Mandich discusses the prudence of retiring King and Sherco 3 on this timeline in her Direct Testimony. Company witness Ms. Wold discusses the nuclear decommissioning trust and depreciation updates further in her Direct Testimony.

Q. WHAT ARE THE COMPANY'S GOALS FOR A TRANSITION TO CLEAN ENERGY?

A. Xcel Energy, Inc. has announced company-wide goals to reduce carbon emissions 80 percent below 2005 levels by 2030 and serve its customers with 100 percent carbon-free electricity by 2050. In our NSP System, working towards this goal will involve modernizing our grid, retiring aging coal-fired generating plants, extending the use of nuclear energy, increasing wind and solar generation, and employing efficient natural gas generation during the transition. Although Xcel Energy is a leader in this area, many of our peer utilities have now announced similar goals.

Q. WHAT FACTORS ARE PUSHING UTILITIES TO TRANSITION TO CARBON-FREE GENERATION OVER THE NEXT FEW DECADES?

A. The electric utility industry is in the relatively early stages of a decades-long transition away from fossil-fueled generation. This transition is driven by a number of factors including the following:

- reduced costs of renewable generation;
- environmental concerns (including among consumers and other members of the public);

- regulatory pressure in some states and the prospect of future regulatory pressure at the federal level;
- higher operation and maintenance costs for certain coal and natural-gas generation facilities (particularly older facilities);
- environmental compliance costs associated with contaminants regulated at the state and federal levels;
- continued efficient operation of nuclear generation facilities;
- the ability to extend the operational lives for nuclear generation facilities;
- advancements in energy storage technologies (and, perhaps more importantly, the prospects for future innovation);
- the lack of fuel costs for solar and wind generation;
- investor and customer concerns about carbon emissions and climate change;
- lower financing costs for renewable resources; and
- the availability of efficient natural gas generation to serve as a lower emission bridge technology during this transitional period.

With all these factors in play, it is no surprise that so many utilities have publicly announced carbon emission reduction goals.

Q. YOU MENTIONED LOWER FINANCING COSTS FOR RENEWABLE RESOURCES, CAN YOU PLEASE EXPLAIN THAT?

A. Yes. The Company has been able to finance wind projects by issuing so-called "green bonds." The proceeds from green bonds are dedicated by issuers to be used for investments in renewable energy projects. One advantage of such bonds is that they attract additional investors who are looking to invest in green projects such as renewable generation, including some investors who focus on such investments, including certain mutual funds. This additional pool of potential investors has resulted in lower-cost financing for the Company, including, for example, a 2.25 percent green bond issued in 2021. In 2021, NSPM issued approximately $850 million in green bonds to finance wind projects. We believe green bonds will continue to play a significant role in Xcel Energy's financing for renewable projects and could also be a possibility for future storage projects. Importantly, customers benefit from the Company's issuance of green bonds because the lower interest rates lower the Company's cost of capital.

Q. HOW DO THE COMPANY'S EMISSION REDUCTION GOALS RELATE TO THIS RATE CASE?

A. The Company's goals are relevant to this case in four key areas: 1) our continued investment in renewable energy generation, including the wind projects we are seeking to roll-into base rates; 2) the capital investments that the Company makes in our industry-leading nuclear fleet; 3) the planned retirement of King and Sherco 3, and 4) our Meter Replacement project, particularly the use of the new meters to promote customers reducing and/or shifting energy usage as discussed in Mr. Mensen's Direct Testimony. The investments and expenses in these areas are tied to the Company's interim goal of reducing carbon emissions 80 percent by 2030. Our subsequent goal of carbon-free electrical generation will require additional technological developments, and the capital improvements and O&M expenses associated with implementing those future technologies will be the subject of future cycles of investment.

Q. WHY ARE CAPITAL INVESTMENTS AND O&M EXPENSES RELATED TO THE NUCLEAR FLEET SO IMPORTANT?

A. Together, the Monticello and Prairie Island nuclear plants make up approximately half of our existing carbon-free generation and one-third of our total generation, providing enough energy to serve more than one million customer homes. The continued role of nuclear generation is therefore critical to our long-term carbon emission reduction goals.

IV. RETURN ON EQUITY

Q. ARE YOU OFFERING AN OPINION AS TO THE APPROPRIATE RETURN ON EQUITY?

A. No, I am not. In his Direct Testimony, Mr. Dylan D'Ascendis is providing his opinion and analysis of the appropriate rate of return, including the return on equity. His recommended figure is then used by Company Witness Mr. Benjamin Halama as an input for the calculation of the revenue requirement. I do not have the expertise to perform the financial analysis necessary to recommend a specific percentage for return on equity. Instead, I will focus in my testimony on the policy reasons for the importance of setting an appropriate return on equity. I will also briefly discuss current economic conditions that are impacting our proposed return on equity.

Q. WHY IS IT IMPORTANT TO SET AN APPROPRIATE RETURN ON EQUITY?

A. As an initial matter, I will note that it is my understanding that the Company is legally entitled to an appropriate return as discussed in Mr. D'Ascendis's testimony. It, moreover, is a sound public policy to set rates using the correct return on equity. When the return on equity is set at a level that is not too low or too high, the result is that the Company is able to attract capital and has the correct incentive to make an appropriate level of investments in serving its South Dakota customers. The Company's past investments have allowed us to provide South Dakota with reliable electricity at a reasonable price, and it is in the interest of the Commission and our customers to incentivize such investments going forward. Therefore, we need a return on equity that reflects the current and emerging economic conditions to continue attracting capital and incentivizing appropriate investments. In addition, an unreasonably low return on equity will also impact our cost of debt.

Q. PLEASE DESCRIBE THE IMPACT ON THE COST OF DEBT.

A. Credit rating agencies and investors consider regulatory risk as a factor when evaluating the risks of purchasing our debt. If the decisions of our state regulators are viewed unfavorably by the credit rating agencies, the result could be an increased cost of borrowing, which would ultimately impact our cost of service. It is important, therefore, that our regulators endeavor to set the appropriate returns on equity to reflect the prevailing market conditions and the Company's performance.

Q. IS THERE A SINGLE, LEGALLY PERMISSIBLE AND REASONABLE RETURN ON EQUITY?

A. No. The legal authorities briefly discussed by Mr. D'Ascendis set the outer bounds. The return on equity should be neither so low as to constitute a taking of property nor so high as to be extortionate; however, there is a range of potential returns on equity in between those two extremes. Within that range, one can also conceive of a somewhat narrower range of reasonable returns on equity. As the Commission knows from its review of numerous rate cases over the years, experts analyzing utilities' rate cases using recognized methodologies can recommend returns on equity that differ materially. In some instances, the Commission may be able to determine that one or another expert is more credible, perhaps as a result of some methodological difference. However, there are also instances in which regulators are presented with a range of potentially reasonable returns on equity to choose among. In those instances, one common approach is to select a mid-point. However, while such a compromise may be appropriate in certain circumstances, I do not believe it is as appropriate for this case given the size of the Company's operations in South Dakota and the Company's performance and the current circumstances in this jurisdiction.

Q. WHAT RELEVANCE DOES THE SIZE OF THE COMPANY'S OPERATIONS IN SOUTH DAKOTA HAVE TO RETURN ON EQUITY?

A. As. Mr. D'Ascendis discusses in his testimony, investors expect higher rates of return from smaller companies. Xcel Energy is obviously not a small company and we are proud of the ways our customers benefit from the economies of scale we are able to provide, including across the NSPM System. However, return on equity is set on a jurisdictional level and the Company's South Dakota operations are relatively small when considered in the context of the equity markets. As a practical matter, there are also ways in which the Company has to act at a jurisdictional level and for which we do not benefit as much from economies of scale. To adequately serve our customers in South Dakota, the Company maintains a local service center and South Dakota-based employees. It is appropriate to set a return on equity consistent with relatively small size of the Company's South Dakota operations. In addition, as I discussed above, the decisions of regulators, including those in less populous jurisdictions, can impact credit ratings.

Q. WHAT CURRENT CIRCUMSTANCES ARE YOU REFERRING TO ABOVE?

A. In part, I am referring to the current economic conditions, which I discuss further below. However, I am also referring to the reliability and quality of the services provided by the Company and the specific nature of the regulatory conditions in South Dakota.

Q. WHAT RELEVANCE DO RELIABILITY AND THE QUALITY OF THE COMPANY'S UTILITY SERVICES HAVE TO SELECTING A RATE OF RETURN?

A. It is widely recognized that it is appropriate for state regulatory commissions to award higher rates of return to utilities with superior service and lower rates of return for utilities that have provided inferior service to customers.[1] The Company has a history of providing reliable service at reasonable rates. As the figures presented by Mr. Mensen in his Direct Testimony demonstrate, the quality of our service has significantly improved since our prior rate case. We have also avoided filing a rate case for approximately eight years, partly thanks to the Commission's decisions with regard to the TCJA and the Infrastructure Rider, but also as a result of the Company's prudent management.

Q. WHAT RELEVANCE DOES THE COMMISSION'S DECISION WITH REGARD TO ROE HAVE TO THE LENGTH BETWEEN RATE CASES?

A. With a relatively higher ROE, the Company is more likely to be able to avoid filing another rate case in the near future. Over time, increases in our costs, which are a particular concern under present circumstances as I discuss below,

[1] *See Missouri ex rel Pub. Counsel v. Pub. Serv. Comm'n*, 274 S.W.3d 569, 576 (Mo. Ct. App. 2009) (stating that courts have consistently held that commissions may award higher ROR for superior service and lower ROR for inferior service).

and new capital additions erode the Company's rate of return. If the Company starts new rates with a rate that is on the lower end of the range of reasonable returns, it is more likely that we will determine that another rate case is necessary in a relatively short period of time. In this respect, regulatory lag is also an important factor to consider.

Q. HOW IS REGULATORY LAG RELEVANT?

A. In South Dakota, the Company must file its rate case using a historical test year. The Commission has ameliorated the regulatory lag associated with the use of a historic test year to some extent by allowing for known and measurable adjustments, but as a general matter it is nonetheless the case that, by the time a rate case is decided and new rates are in place, the costs and rate base upon which those new rates were set are already somewhat outdated. As a result, the erosion of the Company's rate of return has already begun by the time the new rates go into effect.

Q. ARE THERE OTHER ASPECTS OF THE REGULATORY SYSTEM IN SOUTH DAKOTA THAT ARE RELEVANT?

A. The absence of a pre-approval process in South Dakota for major new capital additions is also important. When the Company undertakes significant new projects, it does so with less certainty with regard to ultimate rate recovery than in states which allow for some advanced process. The use of riders can mitigate this issue to some extent and the Company appreciates and is seeking to extend the Infrastructure Rider. However, while riders can allow for a relatively prompt addition of approved and appropriate projects, they do not in and of themselves provide advanced approval and are not appropriate for all types of projects. The risk of undertaking significant new projects without knowing whether or not they will be determined to be prudent is easier for the Company to bear when it is recovering an adequate rate of return on the plant that is already in service. Of course, current economic conditions contribute to the uncertainty.

Q. IS THE COMPANY MAKING ANY OTHER PROPOSALS IN THIS CASE TO ADDRESS REGULATORY LAG?

A. Yes. As Mr. Halama discusses in Section IV of his Direct Testimony, the Company is proposing the use of a year-end rate base as opposed to a 13-month average. The year-end methodology will allow the test-year rate base to be set based on what additions were in place by the close of 2021. This approach has less lag than a 13-month average.

Q. WHAT RELEVANCE DO CURRENT ECONOMIC CONDITIONS HAVE TO THE RETURN ON EQUITY?

A. Currently, the U.S. economy is dealing with inflation at rates that have not been seen for decades. While federal policymakers will attempt to address inflation and the Company certainly hopes those efforts will be successful without causing undue hardship, it seems possible that the impacts of the Russian invasion of Ukraine and the disruptions to global supply chains related to the COVID-19 pandemic will continue to affect prices for goods and services for some time. This inflation is relevant in a few different ways: (1) it generally contributes to an environment in which there is significant risk and volatility in the markets, which can lead investors to seek more of a risk premium; (2) rising costs can impede the ability of the Company to earn a reasonable rate of return; and, (3) increases in interest rates for governmental debt made in an attempt to curb inflation can impact investors' expectations for the rates of return they expect from other investments. The cumulative impact of these factors is that higher rates of return for equity are more appropriate under current circumstances than was the case in the relatively recent past.

V. RATE CASE COMPONENTS

A. Test Year

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

A. The test year is 2021, adjusted to properly reflect regulatory requirements and account for appropriate known and measurable changes. As discussed by Mr. Halama in his Direct Testimony, we include $21 million 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 2022 or 2023. It also includes other additional items such as property taxes and wages.

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 7.65 percent, based on an average common equity ratio of 53.01 percent and an ROE of 10.75 percent. Company Witness Mr. Dylan D'Ascendis provides a detailed analysis of the appropriate overall ROR and ROE for the Company.

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 $291 million, which is an overall base rate increase of $86 million, offset by the elimination of $42 million in 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 $44 million or 17.9 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. Company Witness Mr. Nicholas Paluck discusses this further and identifies the minor proposed rate design changes.

VI. PROPOSED CHANGES TO RATE RECOVERY

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

A. In this section of my Testimony, I discuss the Company's proposed changes to certain ratemaking items related to employee compensation and benefits.

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. In 2021, the Key Performance Indicators are residential customer satisfaction, managing O&M, employee safety, public safety, and electric system reliability.

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. However, as the utility industry changes, and information technology is increasingly integrated into utility operations in new and more complicated ways, the Company requires employees with new sets of skills and finds itself competing more against non-utility employers. For example, Xcel Energy now has a greater need for cybersecurity professionals than at any point it its history and employees with those backgrounds can work in a variety of industries. The result is that maintaining a competitive compensation package is now even more important than was the case in prior generations.

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. This proposed increase from the current 15 percent cap will help the Company recover the costs of employee compensation necessary to attract and retain qualified employees. Company Witness Mr. Halama 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 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 go into LTI: 1) environmental performance, 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, which I discussed earlier in Section III. Debt and equity investors are increasingly interested in Environmental, Social, and Governance (ESG) factors, and progress towards Xcel Energy's stated environmental goals has a significant impact on ESG evaluations. Environmental LTI provides an incentive for key employees to help meet those goals. Positive evaluations of the Company from an ESG perspective benefits our customers by keeping down our cost of capital.

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. Company Witness Mr. Benjamin Halama discusses the impacts on the rate case of allowing for rate recovery of LTI.

VII. 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 $1.50 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.

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 2023.

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. WHAT IS THE ESTIMATED COST OF THIS WAIVER?

A. The Company is conservatively estimating an annual cost of approximately $0.4 million. As Mr. Halama discusses in his Direct Testimony, the Company proposes to establish that amount in the pro forma year revenue requirement and then track actual annual fees above and/or below this baseline between initiating the program and the next South Dakota electric rate case. The net regulatory asset or liability could then be addressed in that future rate case. This approach will avoid over- or under-collection.

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:

- *Benjamin Halama,* who sponsors the overall revenue requirement for the rate case. Mr. Halama sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations.
- *Dylan D'Ascendis,* of ScottMadden, Inc., who sponsors testimony on the ROE and ROR including capital structure and cost of capital.
- *Laurie J. Wold*, who sponsors testimony regarding the Company's material capital additions since the last rate case, depreciation expense and depreciation rates, and nuclear decommissioning accruals.
- *Marty D. Mensen*, who sponsors testimony regarding the Company's distribution capital and O&M budgets and the Meter Replacement project.
- *Farah L. Mandich,* who sponsors testimony regarding the prudence of the planned retirement of the King and Sherco 3 generating plants, the roll-in to rates of wind projects currently recovered in the Infrastructure Rider, the repowering of the 100.5 MW Grand Meadows Wind project, and the cancellation of the Prairie Island Extended Power Uprate project.
- *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 $44 million;
- An overall ROR on investment of 7.65 percent, based on an average common equity ratio of 53.01 percent and an ROE of 10.75 percent;
- Minor changes to our rate design; and
- Allowing the Company to waive charges for credit and debit card payments and treat such costs as O&M expenses going forward.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.