Direct Testimony and Schedules
Greg P. Chamberlain

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-20-___
Exhibit___(GPC-1)

**Policy Testimony**

November 6, 2020

## Table of Contents


| | | |
|---|---|---|
| I | Introduction | 1 |
| II. | Case Overview | 3 |
| III. | Key Developments and Investments in Serving Our North Dakota Customers | 9 |
| IV. | Clean Energy Transition | 20 |
| V. | Rate Case Components | 33 |
| | A. Test Year | 33 |
| | B. Rate of Return | 34 |
| | C. Revenue Requirements | 34 |
| | D. Rate Design | 35 |
| VI. | Proposed Changes to Rate Recovery | 35 |
| VII. | Introduction of Company Witnesses | 40 |
| VIII. | Conclusion | 41 |


## Schedules


| | |
|---|---|
| Statement of Qualifications | Schedule 1 |
| Compliance Table | Schedule 2 |

## I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND JOB RESPONSIBILITIES.

A. My name is Greg P. Chamberlain. I am the Regional Vice President for Northern States Power Company (Xcel Energy or the Company), a Minnesota corporation operating in North Dakota. In this role, I am responsible for state government relations and regulatory filings with the utility commissions in Minnesota, North Dakota, and South Dakota, including proceedings related to rates, resource planning, and service quality filings.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I joined Xcel Energy in 2000 and since that time have held various positions in the Company, including in the Transmission and Energy Supply business areas where I worked prior to serving as Regional Vice President for Government and Community Relations, which was the position I held before moving to my current role. While serving as Director of Transmission Portfolio Delivery for the Company, I was responsible for the engineering, project management, project controls, and permitting of a $4 billion electric transmission capital portfolio across 10 states. In addition, I acted as Xcel Energy's management committee representative on each of the four CapX2020 projects. As General Manager of Power Generation, I was responsible for the operation of the Company's non-nuclear fleet of power plants in the upper Midwest. I have a Master of Business Administration degree from the University of Minnesota's Carlson School of Management and a Bachelor of Science degree in Chemical Engineering from Purdue University. Exhibit ___ (GPC-1), Schedule 1 summarizes my qualifications.

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 North 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;
- Serving North Dakota;
- Clean Energy Transition;
- Rate Case Components;
- Proposed Changes to Rate Recovery;
- 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 North Dakota Public Service Commission Rules and Orders from previous electric rate cases and other dockets to ensure we have complied with the Commission's requirements. My Exhibit___ (GPC-2), 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 $22.228 million, or 10.8 percent. The increase reflects an additional $42.4 million through base rates, offset by the elimination of $20.2 million in Transmission Cost Recovery and Renewable Energy Rider (TCR and RER, respectively) charges. We base this request on a 2021 future test year as allowed by North Dakota law. The test year revenue requirement reflects a Return on Equity (ROE) of 10.20 percent and an overall Rate of Return (ROR) of 7.35 percent. Under our proposal, a residential customer using 7500 kWh per month would see a monthly bill increase of about $8.43 per month or 10.02 percent.

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

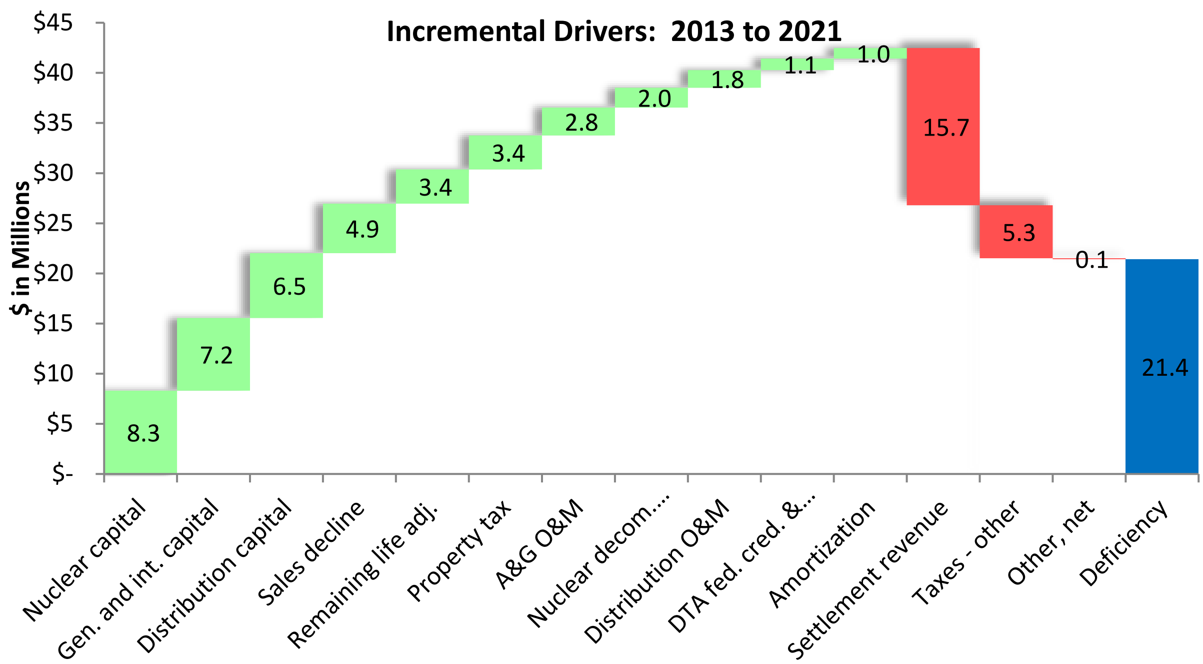
A. The Company last set base rates in its 2012 rate application (using a 2013 test year) (Case No. PU-12-813). At the time, the Company was crossing the peak of an investment cycle in which it was investing in refreshing and upgrading the system. In the policy testimony filed in that case, the Company explained it was then in "in a cycle of significant system investment," including 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 in light of 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.

Since 2013, we have made approximately $10 billion in capital additions. As a result of our investments, our system is more robust and reliable, and our customers benefit from a diverse mix of generation. Many of our capital investments, including various wind projects that are keeping fuel costs down, have received Advanced Determinations of Prudence (ADPs) from the Commission. Our purchased power, wind and other renewable energy projects are being recovered in the Fuel Cost Rider (FCR) or the RER, but not all of our generation investments are rider eligible and currently being recovered. The impacts of our capital investments are driving the need to increase rates when viewed through the prism of our last case.

With that said, the outcome of our last rate case not only set base rates for 2013 but ultimately resulted in a multi-year outcome, setting rates for 2014, 2015, and 2016 as well. In addition, the Company, through two subsequent settlements with Advocacy Staff, also agreed to rate case moratoriums in 2017, 2019, and 2020. The results of the multi-year outcome from our 2012 rate application as well as subsequent settlements provided the Company with additional base rate revenue, additional rider revenue, and cost savings from the Tax Cut and Jobs Act (TCJA) that allowed us to continue to earn a reasonable rate of return over the past 8 years without seeking rate relief through a general rate case, even as we continued to make capital investments and our cost of service increased.

Figure 1, below, identifies the various categories of costs driving our current revenue deficiency when compared to currently approved rates (*i.e.*, those established using a 2013 test year). As Figure 1 below indicates, additional revenue sources have kept up with the increasing costs of operating our business, but the impact of our capital investments is now driving the need for a rate case.

**Figure 1**




*Note this figure compares the 2021 test year to the 2013 test year which had a remaining deficiency of $0.8 million therefore the incremental deficiency above is different than the actual test year deficiency discussed by Company Witness Mr. Benjamin Halama.

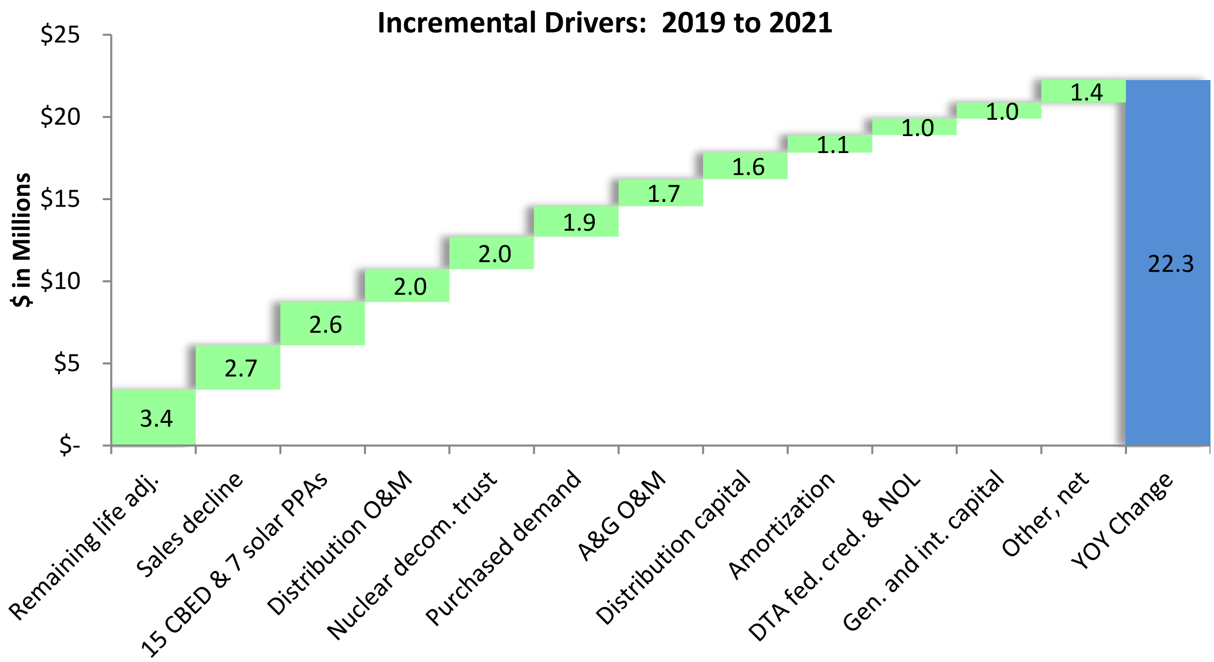
As can be seen in Figure 1, the revenue requirements from investments in our nuclear fleet, in refreshing and updating our information technology, and supporting and improving the reliability of our North Dakota distribution system essentially equal the revenue deficiency requested in this case. These investments have resulted in tremendous value for our customers and fully complete the investment cycle that was the driver of our last rate case. I discuss the benefits of these investments further below and additional information regarding these investments is provided in the Direct Testimonies of Mr. Mark P. Moeller and Ms. Kelly A. Bloch.

As can also be seen in Figure 1, additional revenues from the Settlement of our last rate case and cost savings from the TCJA have allowed us to manage the increasing costs of operating our business. However, as Company Witness Ms. Jannell Marks discusses in her Direct Testimony, the Company has seen its overall sales decline since 2013, and we continue to forecast sales declines from our last full fiscal year of 2019. In light of the fact the we must recover our fixed cost of service with fewer kWh of sales, we no longer have the opportunity to earn the reasonable rate of return on our investments necessary to attract capital without additional rate relief. This is consistent with the forecasts relied on by the Company and Advocacy Staff when a rate moratorium through 2020 was agreed to and approved by the Commission in Case No. PU-18-155.

Q. HOW DO THE COMPANY'S COSTS AND REVENUES IN THE 2021 TEST YEAR COMPARE TO 2019 ACTUAL RESULTS?

A. Compared to 2019 actual results, the Company has increased costs in the 2021 test year including higher distribution expenses, increased capacity costs, and other increased costs due to the passage of time and modernization of our generation assets, transmission system, and distribution system. In addition, retail revenue is decreasing. Figure 2 provides this view.

**Figure 2**




*Note this figure compares the 2021 test year to the 2019 actual year results thousand therefore the incremental deficiency above is different than the actual test year deficiency discussed by Company Witness Mr. Benjamin Halama.

Figure 2 indicates that, while no single cost driver represents a significant contribution to the 2019 to 2021 revenue deficiency, there are various costs of running our business that are increasing. One can see that retail sales are declining, and the passage of time since our last rate case and its impact on depreciation, taxes, and the amortization of deferred costs all result in a material revenue deficiency and the need for rate relief. Company witness Mr. Benjamin Halama discusses these drivers further in his Direct Testimony.

Q. HAS THE COMPANY CONSIDERED THE IMPACT OF THE COVID-19 PANDEMIC ON ITS RATE REQUEST?

A. Yes. We recognize that our rate request will impact our customers during these difficult times and we acknowledge that this request comes also as COVID-19 has further exacerbated our need for rate relief.

The impact of COVID-19 on the Company's deficiency is real and pronounced. Figure 1 shows that sales declines since 2013 are contributing to almost $5 million of our deficiency. And, as shown in Figure 2, the impact of the sales decline accounts for more than ten percent of the overall deficiency from 2019-2021. Company Witness Ms. Jannell Marks discusses the impact of COVID-19 on our sales and how that is driving the need for rate relief.

That said, and as I discussed earlier, a material portion of our revenue deficiency is due to the passage of time since our last rate case and the need to update certain ratemaking factors such as depreciation and tax treatment. In light of this, the Company believes there may be opportunities to work with Advocacy Staff to develop and agree to innovative solutions during this rate case to mitigate the impacts of the Company's needed rate relief on customers. We look forward to working with Staff and the Commission during this rate case to find opportunities to resolve this rate case efficiently and in ways that can help us support our customers in these unique times.

Q. HAS THE COMPANY TAKEN ANY ACTIONS TO PROVIDE RELIEF TO NORTH DAKOTA CUSTOMERS IMPACTED BY THE COVID-19 PANDEMIC?

A. Yes. The Company recognizes that the COVID-19 pandemic and the resulting economic impacts are affecting North Dakota. Accordingly, the Company suspended account disconnections through the summer and waived late fees for many of our customers. As the COVID-19 pandemic continues for a longer time than initially expected, we will be reconsidering what additional measures we can take to help support our customers. Providing the rate relief requested will give us additional resources we can use to help our customers through this difficult time.

Further, the Company has accelerated some planned investments to help support our communities through increased investment, tax base, and construction jobs. For example, in Case No. PU-20-425, we recently requested an Advanced Determination of Prudence for a portfolio of wind repowering projects that includes one of our North Dakota-based wind projects, Border Winds. By making these investments now, we can direct our resources in ways that could support all of our customers by lowering costs in the long-term while also directly investing in our communities. We look forward to further discussion of opportunities for direct investments into North Dakota now and into the future as part of this rate case.

## III. KEY DEVELOPMENTS AND INVESTMENTS IN SERVING OUR NORTH DAKOTA CUSTOMERS

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

A. In this section I describe the Company, the outcome of our last rate case to provide context for our current rate request, as well as key Company developments since our last rate case and how these developments are driving our need for rate relief.

Q. PLEASE DESCRIBE THE COMPANY.

A. Xcel Energy serves more than 1.5 million electricity customers in North Dakota, South 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 power plants with a net maximum capacity of almost 9,190 MW, more than 8,400 miles of transmission lines, and approximately 548 transmission and distribution substations.

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 North 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 Case No. PU-12-813 in December 2012 using a 2013 future test year. That 2013 test year is now more than seven years old, but the 2013

Cost of Service is still the baseline for our current rate structure, though two additional step increases were implemented in 2014 and 2015.

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

A. Pursuant to the Settlement Agreement in Case No. PU-12-813, the Company increased rates by 4.9 percent in each of 2013, 2014, and 2015. We also were in a rate case moratorium in 2016 and 2017 and again in 2019 and 2020.

Q. PLEASE DESCRIBE THE RATE CASE MORATORIUM.

A. Pursuant to the Settlement Agreement in Case No. PU-12-813 and the subsequent Negotiated Agreement in the same docket, the Company agreed not to seek an increase in rates in 2016 and 2017. Moreover, in a Settlement in Case No. PU-18-155 the Company agreed not to increase rates in either 2019 or 2020 in response to the Commission's investigation of the impacts of the Tax Cuts and Jobs Act (TCJA).

Q. WHAT TRENDS HAS THE COMPANY SEEN IN RETAIL SALES SINCE 2013?

A. From 2010 to 2019, North Dakota retail sales decreased by an average of 0.1 percent per year. The decline is not all that surprising, given the growth constraints imposed on our North Dakota service areas due to the state's Territorial Integrity law. And, more recently, Xcel Energy has been experiencing a historic decrease in North Dakota retail sales attributable to the COVID-19 pandemic, and we are forecasting a 2.6 percent decrease in 2020 sales compared to 2019. For 2021, the Company is forecasting a 0.5 percent annual increase in North Dakota retail sales, which would represent a partial recovery of sales lost since 2019.

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

A. Xcel Energy has made approximately $10 billion in investments into the NSP System to provide safe, reliable, and affordable electricity to our customers. This amount reflects total investments by the Company in the NSP System but only those electric distribution investments made to the North Dakota jurisdiction.

Q. WHAT WERE THOSE INVESTMENTS?

A. As can be seen on Figure 1 above, key capital investments have been made at the Prairie Island and Monticello nuclear plants, including the Monticello life cycle management and extended power uprate project and the replacement of the Unit 2 steam generator at Prairie Island. 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 Advanced Grid Intelligence and Security (AGIS) initiative. In addition, 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 investments are discussed by Company witness Mr. Mark Moeller in his Direct Testimony.

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

A. Yes, the largest category of capital investments over the last seven years involved Xcel Energy's nuclear fleet. 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 the steam generator at Prairie Island; 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 are continuing in 2020 and are planned for 2021, including reloading of nuclear fuel in Prairie Island Unit 1, further security enhancements, replacement of process control equipment, expansion of the Prairie Island Independent Spent Fuel Storage Installation, and cooling tower refurbishment. Company Witness Mr. Mark Moeller discusses these investments further in his 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, enabling both plants to continue operating at 95 percent capacity or above. 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 2013, the Company's nuclear fleet, which has operated safely since the 1970s, is now even safer, more secure, and more resilient. Indeed, as this testimony is filed, all of our nuclear units are in

Exemplary Status as determined by the Institute of Nuclear Power Operations (INPO), all units are in the Nuclear Regulatory Commission's (NRC) Column 1 Status with all green performance indicators, and all units have no NRC Safety Culture Concerns. 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 North Dakota consumers while transitioning to cleaner resources.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN WIND GENERATION SINCE 2013.

A. To harness the excellent wind resource of North 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 $1.3 billion to build 800 megawatts (MW) of new wind facilities across its system between 2013 and 2019.

The Commission granted ADPs for most of these additions, given the significant benefits that the projects provided to North Dakota customers, including cost savings and a hedge against the volatility of natural gas prices and potential environmental regulation. The Company is continuing to invest in wind generation in 2020 and 2021, and certain such investments are the subject of separate ADP proceedings.

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 $1.8 billion in transmission assets, including in regional expansion transmission projects. This includes projects in North Dakota, South Dakota, and Minnesota as part of the CapX2020 initiative. The Company also plans on investing in regional transmission projects in 2021. For example, the Company forecasts a capital addition of $63 million for the Huntley-Wilmarth Project, which is a Midcontinent Independent System Operator, Inc. (MISO) designated Market Efficiency Project that is designed to provide economic benefits by providing additional transmission capacity to allow low-cost wind generation in southern Minnesota and northern Iowa to reach NSP System customers.

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. The Commission granted an ADP for this investment in Case No. PU-13-194 (Order Adopting Settlement, Feb. 26, 2014).

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS TO MODERNIZE ITS DISTRIBUTION SYSTEM.

A. The Company is now investing to modernize the distribution system in all of the states we serve through our Advanced Grid Intelligence and Security

(AGIS) initiative. The AGIS initiative is a long-term strategic plan to transform our electric distribution system to meet multiple ends, including the promotion of efficiency and reliability, and the safe integration of more distributed resources into our system. This initiative will build an advanced electric grid that is more resilient and provides more tools and options for customers. With the need to replace our customers' electric meters in the next 3 to 4 years, we plan to take advantage of the transition period to put more smart technology in place for the long-term benefit of our customers and our overall system. AGIS, and the advanced grid it will create, will offer a number of customer benefits, which are discussed in detail by Ms. Kelly Bloch.

Q. IS THE COMPANY STILL IN A CYCLE OF SIGNIFICANT CAPITAL INVESTMENT?

A. The Company has passed the peak of its cycle of significant capital investment highlighted in Case No. PU-12-813, which was focused on refreshing and replacing aging infrastructure. Now, Xcel Energy is entering a new cycle during which its capital investments are more aimed at transforming and improving the Company's generation, transmission, and distribution systems as the utility industry continues to evolve. Of course, a certain level of basic capital investment is also needed every year to keep the NSP System reliable.

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

A. Yes. Two other significant impacts to our cost of service since 2013 are the need to update our depreciation expense and to further fund our nuclear decommissioning trust. Specifically, we need to update our depreciation rates in response to updated information, as depreciable lives for our plants and other infrastructure have not been updated in North Dakota rates since 2008 in Case No. PU-07-776. The most significant change in this regard is the need to update the retirement dates for Units 1 and 2 at Sherco. 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. I discuss our carbon reduction plans further in Section III. Company witness Mr. Mark Moeller discusses this and the nuclear decommissioning trust updates further in his Direct Testimony. Company Witness Mr. Christopher Shaw discusses the prudence of retiring Sherco Units 1 and 2 in his Direct Testimony.

Q. IS THE COMPANY FILING A RATE CASE NOW IN RESPONSE TO THE CAPITAL INVESTMENTS MADE SINCE 2013?

A. Yes. When staff and the Company negotiated the multi-year Settlement Agreement in Case No. PU-12-813, we all were aware that the Company was in the process of making significant capital investments, and the terms of the settlement provided for some additional revenues resulting from scheduled rate increases in 2013, 2014, and 2015. Those increases resulted in sufficient revenue increases to cover the Company's increased costs, for a period.

Then, the passage of the TCJA resulted in tax savings, and the settlement with the Commission in Case No. PU-18-155 allowed Xcel Energy to retain those savings and apply them toward the recovery of the associated revenue requirements of the ongoing cycle of capital investment.

Taken together, the capital additions made since 2013 which were not recoverable under applicable riders, coupled with the passage of time since our last general rate increase, are driving the need to seek rate relief. These important additions and the decrease in retail sales have, as a general matter, offset the increased revenue resulting from the annual Settlement rate increases and the decreased costs resulting from the TCJA.

Q. WHAT COSTS ARE CREATING A REVENUE DEFICIENCY FOR 2021?

A. As noted above, capital spending and the passage of time since our last rate case, as well as decreasing sales are the primary deficiency drivers. There are also several other factors contributing to increased costs in the 2021 test year. The additional revenue from the multi-year step increases approved in the last rate Settlement and the savings the Company was allowed to keep from the TCJA would be sufficient to cover the increased costs if it were not for the capital investments made since we filed our last rate case.

Q. IN ADDITION TO THE CAPITAL INVESTMENTS, PASSAGE OF TIME, AND DECREASE IN SALES, WHAT ARE THOSE OTHER FACTORS CONTRIBUTING TO A REVENUE DEFICIENCY?

A There are several factors.

The change in depreciation resulting from a reduction in the remaining lives of Sherco Units 1 and 2 is a significant factor; this is further discussed in the Direct Testimonies of Company Witnesses Mr. Mark Moeller and Mr. Christopher Shaw.

The Company's administrative and general O&M costs have also increased in light of the premium refund from one of the Company's mutual insurers, NEIL, which offset certain costs in 2019, but which is not expected to be repeated in the test year. Company Witness Mr. Benjamin Halama discusses this further in this Direct Testimony.

As Company Witness Ms. Kelly Bloch discusses, certain costs associated with the AGIS initiative as well as other Distribution O&M costs are also increasing.

Purchased demand expenses, which are not recoverable through the Fuel Cost Rider as purchased energy costs, are increasing as a result of the PPAs with Manitoba Hydro and the PPA for Unit 2 of the Mankato Energy Center (MEC II). Company Witnesses Mr. Benjamin Halama and Mr. Christopher Shaw discuss the increases in our purchased demand costs.

There are Other Production O&M costs in the test year resulting from new, Commission-approved wind sources. The revenue requirement impacts of establishing a regulatory asset to levelize associated wind energy PTCs over the life of each project, as requested by the Commission, is also a factor. These costs are further described in the Direct Testimony of Company Witness Mr. Benjamin Halama.

Q. IS THE COMPANY INTERESTED IN ANOTHER MULTI-YEAR OUTCOME SIMILAR TO WHAT WAS ULTIMATELY APPROVED IN ITS LAST RATE CASE?

A. Consistent with North Dakota law, the current rate case filing reflects a single, future test year. As in previous rate applications, we look forward to opportunities to discuss with Commission Staff creative ways to resolve this rate case quickly and efficiently. Should a multi-year solution present itself during such discussions, the Company would be willing to seek a mutually acceptable settlement outcome that could include a multi-year solution. The Company has also reached agreements in prior years on multi-year rates with regulators in Minnesota and believes that the resulting rate stability and predictability is to the benefit of customers and the Company, provided consensus can be reached regarding the appropriate design for a multi-year rate.

## IV. CLEAN ENERGY TRANSITION

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

A. In this section of my testimony, I describe Xcel Energy's plans to transition to clean energy, why this plan is important to the Company's and our customers' future, and the impact of our clean energy transition on this rate case.

Q. WHAT IS XCEL ENERGY'S CLEAN ENERGY TRANSITION?

A. Xcel Energy, Inc. has announced company-wide goals to reduce carbon emissions 80 percent from 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 use of nuclear energy, increasing wind and solar generation, and employing efficient natural gas generation during the transition.

Q. HAVE ANY OTHER UTILITIES ANNOUNCED SIMILAR GOALS?

A. Yes. While Xcel Energy is and has been a leader in the development of renewable resources and the transition away from fossil-fueled generation, many other utilities have since announced similar targets. Duke Energy, Southern Company, and Dominion Energy have all announced a goal of achieving net zero carbon emissions by 2050. Arizona Public Service has announced a 100 percent carbon free energy by 2050 goal, American Electric Power announced an "aspirational" goal of zero carbon emissions by 2050, Public Service Enterprise Group (PSEG) has a "vision" of being carbon free by

2050, Wisconsin's MGE Energy has a goal to be carbon neutral by 2050, and in Michigan, DTE Energy has a goal of net zero carbon emissions by 2050.

Some utilities have announced even more aggressive plans to achieve carbon neutrality, zero carbon emissions, or 100 percent clean energy goals. Avangrid has a goal of carbon neutrality by 2035, Avista Energy's goal is carbon neutrality by 2027 and all clean electricity by 2045, Consumers Energy (CMS) in Michigan has a goal of net zero carbon emissions by 2040, Eversource's goal is carbon neutrality by 2030, and Idaho Power has announced its goal of 100 percent clean energy by 2045.

In addition, various other utilities have announced significant carbon emission reduction goals even if they have not made commitments to completely stop carbon emissions (or net carbon emissions) by a particular year. For example, the Tennessee Valley Authority has announced that it is on track to reduce carbon emissions by 70 percent from 2005 levels by 2030, El Paso Electric has a goal of reducing its carbon footprint by 40 percent (from 2015 levels) by 2035, and NiSource (NIPSCO) has a target of a 50 percent reduction in greenhouse gas emissions by 2025 (from 2005 levels).

In addition to these examples, other utilities that have announced carbon reduction, or elimination, goals as of the date of this filing are: AES, ALLETE, Alliant, Ameren, CenterPoint, Entergy, Exelon, FirstEnergy, Green Mountain Power, Hawaiian Electric, National Grid, NextEra, OG&E, PG&E, Portland General Electric, PPL, Puget Sound Energy, Southern California Edison, Tucson Electric Power, UGI Utilities, Vectren, and WEC Energy Group.

Across the industry, utilities of various sizes, with different business models and fleets, operating in a variety of jurisdictions, including in jurisdictions where public utility commissions and state legislatures are traditionally supportive of fossil fuel generation, have recognized that transitioning to lower-carbon generation and, eventually, carbon-free generation is the prudent course of action.

Q. WHAT ABOUT THE OTHER INVESTOR-OWNED UTILITIES IN NORTH DAKOTA?

A. While Otter Tail Power Company and MDU Resources have not announced goals to achieve carbon-free generation by some set date, both have stated carbon emission reduction goals. MDU has a target of reducing its carbon emission intensity by 45 percent by 2030 (from 2005 levels). For its part, Otter Tail Power has stated that by 2022 it will have reduced carbon emissions by nearly 30 percent (from 2005 levels). Also, as the Commission knows, the move away from carbon-intensive generation is resulting in the closure of several coal-fired plants, including facilities located in or serving North Dakota. Otter Tail Power's Hoot Lake facility is slated for closure in 2021, MDU's Lewis & Clark Unit 1 is also to close in 2021, and Units 1&2 at MDU's Haskett plant are scheduled for a 2022 closure.

In addition, Great River Energy closed the Stanton facility in 2017, and also plans to close the Coal Creek facility by the end of 2022.

The Company's decision to move forward the retirement dates for Sherco Units 1 and 2 is thus consistent with the decisions regarding coal-fired plants in North Dakota, including those owned by other utilities in the state. The transition away from coal generation and towards lower carbon and carbon-free generation is already well underway both nationwide and in North Dakota.

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 (and trends and forecasts suggesting those costs will continue to decrease);
- 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 (MATS standards, for example, resulted in the closure of some older coal plants);
- 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 low-cost, 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. HOW DOES THE COMPANY PLAN TO MANAGE THIS TRANSITION?

A. The transition away from carbon-emitting generation is going to continue and will benefit Xcel Energy's customers, particularly if it is carefully planned and managed as the Company intends and has been doing. As a result of its continuing leadership in the use of renewables, an effort in which North Dakota-based wind generation plays a crucial part, and its recent investments in its nuclear fleet, Xcel Energy is already in a strong position to manage the transition to carbon-free generation over the few decades. By being an industry leader and setting an ambitious goal (that other utilities have also subsequently sought to achieve), the Company is positioning itself to thoughtfully and efficiently transitioning for the ultimate benefit of consumers.

As we transition toward carbon-free generation we are working to keep costs down through the use of low cost renewable generation, the low cost and efficient management of the Company's nuclear fleet, the replacement of fossil fuel costs with fixed assets (the Company's "Steel for Fuel" strategy), the low costs of natural gas generation (during the transitional period), and favorable financing costs for renewable resources. By starting the transition to carbon-free generation early and making the necessary improvements to our system (including certain investments that have already been made or are underway), Xcel Energy will be able to manage this transition in a manner that keeps electricity affordable while maintaining reliability.

If the Company were to postpone or unduly slow the process, it would risk a future in which it would have to undertake substantial changes in generation and transmission assets in a relatively short period of time, which is more likely to lead to excessive costs and reliability concerns. While Xcel Energy believes the trend toward de-carbonization will continue even without action at the Federal level, a renewed Federal effort in regulating carbon emissions could accelerate trends, perhaps as a result of electoral politics over the next ten to fifteen years.

Q. YOU MENTIONED A LOWER FINANCING COST FOR RENEWABLES, 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 or renewables, including some investors who focus on investments such as socially responsible mutual funds. This additional pool of potential investors has resulted in lower-cost financing for the Company, including, for example, a 3.7 percent green bond issued in September 2019, which set a record for the lowest interest rate for a 30-year utility bond in history. In 2018 and 2019, we issued approximately $580,000,000 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. Additionally, customers benefit from the Company's issuance of green bonds because the lower interest rates lower the Company's cost of capital.

Q. YOU ALSO REFERRED TO INTEREST AND PRESSURE FROM INVESTORS. PLEASE EXPLAIN.

A. Increasingly, investors, including large institutional investors, are considering the impacts of greenhouse gas emissions when making investment decisions. Some of Xcel Energy's largest institutional investors are members of Ceres and/or Climate Action 100+, which are both groups of institutional investors who make efforts to push corporations to reduce their carbon emissions. Some of the institutional investors in question include Black Rock, JP Morgan Asset Management, State Street, Pictet Asset Management, and CalPERS. Those investors who push for emission reductions typically make the point that efforts to reduce emissions promote the long-term value of a company. For example, in an open letter to CEOs, Black Rock's Chairman and CEO described climate risk as an investment risk and indicated that his firm would increasingly be evaluating companies based on whether "companies are properly managing and overseeing these risks within their business and adequately planning for the future."

Investment analysts have also recognized the advantages of a transition toward carbon-free generation. For example, in a December 2019 report, analysts at Morgan Stanley touted the economic benefits of replacing coal generation with lower-cost renewables.

Q. IN THE NEGOTIATED AGREEMENT IN CASE NO. PU-12-813, XCEL ENERGY COMMITTED TO BUILD THERMAL GENERATION IN EASTERN NORTH DAKOTA WITH A CAPACITY OF AT LEAST 200 MW BY THE END OF 2025, CONSISTENT WITH PRUDENT RESOURCE PLANNING PRINCIPLES. WHERE DOES THAT COMMITMENT STAND IN LIGHT OF THE COMPANY'S GOALS?

A. The Company recognizes its prior commitment, and our current long term resource plan also reflects the need for additional resources in the mid-2020s and our commitment to building generation in North Dakota. The precise resource types and timeframes during which they would be added is not yet certain but will be considered in the Action Plan included in our next resource planning cycle. We recognize that natural gas generation plays an important role in our long-term transition away from carbon emissions. However, the lifespan of that natural gas facility could be somewhat limited due to the Company's 2050 goal; accordingly, the Company is open to discussing possible alternatives to the project, if the Commission so desires.

Q. HOW DOES THE COMPANY'S CARBON-FREE GOAL FIT WITH THE RESOURCE TREATMENT FRAMEWORK ADDRESSED IN CASE NO. PU-12-813?

A. In the Settlement Agreement in Case No. PU-12-813, the Company and Staff agreed to work together to develop a methodology to reflect a "restacking" of the resources on the NSP System for purposes of ratemaking in North Dakota. Later, the Company and Staff agreed to the Negotiated Agreement, which was approved by the Commission and included, among other things, a requirement for the Company to put forward a "Resource Treatment Framework" or "RTF" that would better reflect North Dakota energy policy in its North Dakota rates. The Company met those commitments through its subsequent RTF filing in

Case No. PU-12-813, and its filing on December 21, 2018, which presented a proposed North Dakota Resource Planning (NDRP) framework.

At a high-level, the RTF is the Company's proposal to resolve the misalignment among North Dakota, South Dakota, and Minnesota policymakers with respect to the types of resource additions proposed by the Company for the NSP System. As a practical matter, the misalignment related to higher-cost wind and solar resource additions to the NSP System, which were relevant to the Company's 2030 and 2050 goals. Starting in January 2017, the Company, in collaboration with Commission Staff and the Commissioners, worked to develop a viable RTF. The resulting RTF was composed of two separate, but interrelated, components: (1) development of a new, formal North Dakota Resource Planning procedure for the Company; and (2) implementation of the appropriate ratemaking and resource allocation methodologies (for the associated capacity, energy, revenue, costs, and other attributes) for resources that would not be approved by all of the NSP System states.

However, in the years since 2013, the policy misalignment between North Dakota, South Dakota, and Minnesota has diminished given the much more competitive wind energy prices, such that an RTF may no longer be necessary. In recent years, there has been more alignment of all of the NSP System states with respect to the significant wind resource additions proposed by the Company. Since the Company's last rate case, the Commission granted ADPs for the addition of wind-generation, either owned by the Company or acquired through PPAs, in Case Nos. PU-18-430, PU-17-372, PU-17-120, PU-15-181, PU-13-742, and PU-13-706.

In this rate case, the Company is requesting to reflect in rates its power purchase agreement for MEC II and the 187 MW Solar Portfolio. The Company's ADP request for the proposed purchase of the entire Mankato Energy Center was withdrawn in Case No. PU-18-403, and our ADP request for the solar portfolio was dismissed, without prejudice, in Case No. PU-14-810. The Company believes that these resource additions are prudent and in the best interest of customers based on the information available at the time that the resource decisions in question were made. Company witness Mr. Christopher Shaw provides support for the Company's request. In the event that the Commission does not approve rate recovery for these resource additions in this rate case that have been approved elsewhere, it may be appropriate to apply to those resources ratemaking treatments similar to what was contemplated in the Company's RTF filing.

Q. HOW DOES THIS RATE CASE FILING SUPPORT THE COMPANY'S LONG-TERM GOALS?

A. Investments described in this case generally relate to four key areas: 1) our continued transition to renewable energy generation, 2) our industry-leading nuclear operations, 3) depreciation reserve rates, and 4) our AGIS initiative. 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. HOW DO XCEL ENERGY'S INVESTMENTS IN RENEWABLE ENERGY GENERATION IMPACT THIS FILING?

A. As I have noted above, Xcel Energy has long been at the forefront of the industry with respect to renewable energy, and those efforts continue as we have been engaged in the largest build-out of new wind resources in the Company's history, for which the Commission granted an ADP. Our expansion of renewable generation impacts this rate case filing in two principle ways.

First, as Mr. Halama and I discuss, we propose to "roll in" to base rates a number of wind projects currently being recovered through the Renewable Energy Rider (RER). However, it should be noted that, while the roll-in of these projects will increase base rates, there will not be a material change in customer bills as recovery already occurs through the RER.

Second, the increase in wind generation impacts fuel costs and our O&M expenses. The new wind resources are part of our "Steel for Fuel" strategy; generation sources that require the purchase of coal or natural gas are replaced with wind resources that do not require such fuel. Those reductions have already begun to be reflected in the FCR and will continue to benefit customers going forward, which helps maintain the overall affordability of energy for customers as Xcel Energy continually reduces its use of fossil fuels. Moreover, as renewable sources continue to become a larger part of the fleet, we see a larger part of our O&M budget going toward the maintenance of those renewable facilities. At the same time, we are seeing reductions in O&M expenses for fossil fuel facilities. Last, the tax implications of our shift to renewable resources, which produce federal Production Tax Credits (PTCs), also impact our cost of service through adjustments to our deferred tax asset

(DTA). The DTA allows us to pass the benefits of PTCs to our customers and to levelize the PTC benefits to customers over the life of the given wind project as directed by the Commission. Company Witness Mr. Benjamin Halama discusses the DTA and PTC levelization further in this Direct Testimony.

Q. WHAT RESULTS HAS THE COMPANY SEEN TO DATE FROM THE STEEL FOR FUEL STRATEGY?

A. The Steel for Fuel strategy has been successful. By adding wind resources to the NSP System, the Company has significantly reduced its fuel costs. In 2013, our average North Dakota fuel costs were 2.9 cents per kilowatt hour (kWh). For 2020, we are forecasting that our average fuel costs will be 1.85 cents per kWh. That is a 34 percent reduction. As more wind is added to the system, we anticipate that fuel costs will continue to decline.

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

A. Together, the Monticello and Prairie Island make up more than 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.

Accordingly, O&M and capital expenses for the nuclear fleet are important for maintaining affordable and reliable electrical service while Xcel Energy transitions to carbon-free generation. As I noted earlier, our nuclear plants are operating safely, reliably, and efficiently. The Company made significant capital investments in its nuclear fleet between the 2013 rate case and the date of this filing, and it is appropriate to add such improvements to the rate base.

Q. HOW DO CHANGES IN THE COMPANY'S DEPRECIATION RATES RELATE TO THE COMPANY'S CARBON EMISSION REDUCTION GOALS?

A. In this rate case, the Company is seeking to adjust depreciation expenses for Sherco Units 1 and 2 to reflect the new 2026 and 2023 retirement dates, respectively, for these units. The near-term retirement of Units 1 and 2 at Sherco are a crucial part of the Company's strategy to achieve its goal of reducing carbon emissions by 80 percent by 2030.

Q. HOW DOES THE COMPANY'S AGIS INITIATIVE SUPPORT THE CLEAN ENERGY TRANSITION?

A. As I noted above, the AGIS initiative is a long-term strategic plan to transform our electric distribution system to achieve multiple ends, including the promotion of efficiency and reliability, and the safe integration of more distributed resources and storage into our system. Modernizing the grid is a complex, long-term project. Xcel Energy is taking a leading industry role in grid modernization, and we expect that the investments made now, and the lessons learned in implementing AGIS, will have long-term benefits as the transition to carbon free generation proceeds.

## V. RATE CASE COMPONENTS

### A. Test Year

Q. WHAT INFORMATION IS THE COMPANY PROVIDING TO SUPPORT ITS 2021 TEST YEAR IN THIS CASE?

A. Consistent with N.D.C.C. § 49-05-4.1, the Company includes the following in this application to substantiate its 2021 test year:

a. A comparison of forecast data to historical period data to demonstrate the reliability and accuracy of the utility's forecast including a comparison of the prior years' forecast or budgeted data to actual data for those periods is provided in the Direct Testimony of Company Witness Mr. Benjamin Halama.

b. A statement that the public utility's forecast is reasonable, reliable, and was made in good faith and that all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the commission to test the appropriateness of the forecast is provided in the Direct Testimony of Company Witness Mr. Benjamin Halama.

c. A statement that the accounting treatment that has been applied to anticipate events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred. This information is provided in the Direct Testimony of Company Witness Mr. Benjamin Halama.

### 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 (ROR) on investment of 7.35 percent, based on an average common equity ratio of 52.50 percent and an ROE of 10.20 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 $228.644 million, which is an overall base rate increase of $42.4 million, offset by the elimination of $20.2 million in from the TCR and RER. When the reduction of rider revenue is netted with the Company's request, the overall revenue deficiency sought in this rate case is $22.228 million or 10.8 percent.

Q. IS THE COMPANY SEEKING ANY OTHER ADDITIONAL REVENUE THROUGH THIS RATE CASE?

A. Yes. We are requesting that the Commission allow the recovery for the costs of the 187 MW Solar Portfolio in our FCR as discussed in the Direct Testimony of Mr. Christopher Shaw.

### 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, charitable donation and association dues, and recovery of certain deferred expenses.

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 North 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 2020, the Key Performance Indicators are residential customer satisfaction, managing O&M, employee safety, public safety, and electric system reliability. The Company anticipates using similar Key Performance Indicators for 2021.

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. HOW WAS THE AIP ADDRESSED IN THE LAST RATE CASE?

A. In Case No. PU-12-813, the Company initially sought recovery of AIP costs of up to 25 percent above base pay. However, in settling the matter, Xcel Energy agreed to exclude AIP costs above 15 percent of base pay from rates.

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. Benjamin 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 API, 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 LTI costs. The Company is not seeking to have the other two components 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. As I discussed earlier in Section III, the Company is a leader in seeking to reduce carbon emissions. Xcel Energy's customers will benefit from the Company's transition away from carbon generation, particularly when compared to those companies who are slow to embrace change. The technologies implemented by Xcel Energy will result in efficiencies, allow for a lower cost of capital, and remove fuel costs, in addition to environmental benefits and other benefits. Given the benefits of carbon reduction, which are now recognized in the market as reflected by the actions being taken by so many of Xcel Energy's peers, it makes sense for the Company to provide incentives for its key decision makers to keep the Company on track to reduce carbon emissions 80 percent by 2030 and 100 percent by 2050.

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

Q. WHAT CHANGES IS THE COMPANY SEEKING WITH REGARD TO CHARITABLE CONTRIBUTIONS?

A. Currently, the cost of charitable contributions that benefit North Dakota are not recoverable in North Dakota rates. The Company is proposing that cost recovery of 50 percent be allowed. Charitable contributions are a normal and expected expense for a business, particularly for a corporation of Xcel Energy's size and prominence in the community, and the Company's request is moderate in that it only encompasses half the cost of those donations that directly benefit North Dakota.

The Company is also seeking to recover 100 percent of the cost of a limited set of contributions: donations made to North Dakota state and local economic development entities. Company Witness Mr. Benjamin Halama discusses the rate impact of this change in this Direct Testimony. The impact on rates of the Company's proposal will be quite modest, and North Dakota benefits when the Company makes such contributions.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH REGARD TO CHAMBER OF COMMERCE DUES?

A. The Company is proposing that it be allowed to recover 50 percent of the cost of membership dues for the Greater North Dakota Chamber of Commerce. As with charitable contributions, such dues are a common business expense. Moreover, participation in the Chamber of Commerce can facilitate important discussions between Xcel Energy and other members of the North Dakota business community, including industrial and commercial clients, to the benefit of the Company and its customers. Company Witness Mr. Benjamin Halama discusses the rate impact of this change in this Direct Testimony.

Q. WHAT IS THE RTF EXPENSE DEFERRAL?

A. As I discussed above, the Company, acting pursuant to the Settlement in Case No. PU-12-183, worked to develop and submit an RTF in order to resolve policy misalignments between North Dakota, South Dakota, and Minnesota regarding the types of generation assets that should be added to the NSP System. The Company spent approximately $1.8 million creating the RTF. The recovery of RTF cost was deferred pending adoption of the RTF. Company Witness Mr. Benjamin Halama discusses this further in his Direct Testimony.

## VII. 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.
- *Jannell E. Marks*, who sponsors testimony regarding the Company's sales forecast and demand allocator.
- *Kelly A. Bloch*, who sponsors testimony regarding the Company's distribution capital and O&M budgets and the Advanced Grid Intelligence and Security (AGIS) initiative.
- *Mark P. Moeller,* who sponsors testimony regarding the Company's depreciation expenses, accumulated depreciation, and capital roll-forward.

- *Christopher P. Shaw,* who sponsors the Company's support for the prudence of the MEC II PPA, the adjusted end of life for Sherco Units 1 and 2, the cancellation of the Prairie Island Extended Power Uprate project, the 187 MW Solar Portfolio, and the Company's acquisition of the Community Wind North and Jeffers Wind repowering projects.
- *Michael Pepin*, who sponsors our class cost of service study.
- *Nicholas Paluck*, who sponsors rate design and tariff changes.

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

## VIII. 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 $22.228million;
- An overall ROR on investment of 7.35 percent, based on an average common equity ratio of 52.50 percent and an ROE of 10.20 percent; and
- Minor changes to our rate design.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota | ) ) ) ) | Case No. PU-20-___ |

**AFFIDAVIT OF**
**Greg P. Chamberlain**

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Greg P. Chamberlain

Subscribed and sworn to before me, this 30 day of October, 2020.

Notary Public
My Commission Expires: January 31, 2025

STEVEN DELMONT SPIESS
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2025

# Statement of Qualifications

## Greg P. Chamberlain

## Vice President for Regulatory and Government Affairs
## Northern States Power Company - Minnesota

Greg Chamberlain is Xcel Energy's Regional Vice President for Regulatory and Government Affairs. He is responsible for state government relations and regulatory filings with the utility commissions in Minnesota, North Dakota and South Dakota.

He previously served as Regional Vice President for Government and Community Relations for the Company, overseeing state and local government relations for Minnesota, North Dakota, and South Dakota.

Prior to that, Chamberlain served as General Manager of Power Generation, where he was responsible for the operations of the Company's non-nuclear fleet of power plants in the upper Midwest.

As Director of Transmission Portfolio Delivery for the Company, Chamberlain was responsible for the engineering, project management, project controls and permitting of a $4 billion electric transmission capital portfolio across 10 states. In addition, he acted as Xcel Energy's management committee representative on each of four CapX2020 projects. CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region, investing $2 billion to expand the electric transmission grid to ensure continued reliable and affordable service.

Chamberlain joined Xcel Energy in 2000 as a market segment manager with responsibility for marketing power and ancillary services in newly deregulated markets, and then joined the Transmission organization in 2006.

Before joining Xcel Energy, Chamberlain spent five years at Suez leading energy, water and chemical outsourcing initiatives in a variety of heavy industries. Prior to that role, he spent nine years at Hercules, Inc., now part of Ashland Chemical.

Chamberlain earned a Master of Business Administration degree from the University of Minnesota - Carlson School of Management and a Bachelor of Science degree in chemical engineering from Purdue University. He serves on the boards of directors of Catholic Charities of St. Paul and Minneapolis and the Boy Scouts of America Northern Star Council.

**FILING REQUIREMENT COMPLIANCE TABLE**

| | | |
|---|---|---|
| Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in North Dakota | ) ) ) ) | Case No. PU-20-___ |

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| **N.D.C.C. 49-05-04. Application for increase of rates – Information required – Fee.** | Any public utility requesting an increase in its rates above the maximum approved or prescribed by the commission shall furnish the commission: | |
| | 1. The original cost of all its property. | Consistent with Commission precedent,[1] the Company is providing capital roll-forward reports from 2013-2019 and 2020-2021. *See* Mark Moeller, Exhibit___ (MPM-1), Schedules 2a & 2b. |
| | 2. The date of the acquisition of said property. | See above. |
| | 3. The amount of money invested in said property. | See above. |
| | 4. The amount of stock outstanding. | Dylan D'Ascendis, Exhibit___(DWD-1), Schedule 2: Financial Profile of the Company. |
| | 5. The amount of bonds outstanding against said property. | Dylan D'Ascendis, Exhibit___(DWD-1), Schedule 2: Financial Profile of the Company. |
| | 6. All books, papers, and memoranda of the utility showing the financial condition thereof. | Volume 3, Test Year Work Papers. |
| | 7. Its total monthly salaries and wage expense for such time as the commission may request. | Volume 3, Test Year Work Papers. |
| | 8. An itemized statement of its expenditures. | Volume 3, Test Year Work Papers. |
| | 9. The details of its profit and loss account. | Volume 3, Test Year Work Papers. |
| | 10. All other books, papers, vouchers, and accounts which the commission shall ask to have produced as evidence at the hearing. | N/A. *See* Volume 3, Test Year Work Papers. |

[1] *See* PU-12-813, NSP Test Year Workpapers, Sec. III, Tab P3.B; PU-17-398, Otter Tail Power Rate Base Schedule B-3; PU-20-379, Montana-Dakota Utilities Co. Workpapers, Statement B-1.

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| | 11. An application fee in the amount of one hundred seventy-five thousand dollars. Upon request of the commission and with the approval of the emergency commission, the applicant shall pay such additional fees as are reasonably necessary for completion of the application process by the commission. The commission shall pay the expenses of investigating a rate increase application under this section from the application fee paid by the public utility in accordance with section 49-02-02. The commission may waive or reduce the fee. | Application Cover Letter, p. 2-3.<br><br>The application fee is being sent to the Commission under separate cover. |

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| **N.D.C.C. 49-05-04.1. Test year – Public utility rate filings.** | 1. A public utility, at its option, may use any one of the following twelve-month periods as its test year for rate filings with the commission: | |
| | a. A historical test year, which may be either the latest twelve-month period for which actual data is available at the time of filing new schedules or the latest calendar or fiscal year for which actual data is available at the time of filing new schedules. | N/A |
| | b. A current test year, which is any consecutive twelve-month period ending not later than twelve months after the date new schedules are filed. A public utility selecting a current test year also shall file data for the twelve-month period immediately preceding the current test year selected and that period is the "historical period" for the public utility. | N/A |
| | c. A future test year, which is any consecutive twelve-month period ending no later than twenty-four months after the date new schedules are filed. A public utility selecting a future test year must file data for the twelve consecutive months immediately preceding the future test year and that period is the "current period" for the public utility. | Benjamin Halama, Exhibit___(BCH-1), p. 18-19, Schedule 3A. |
| | 2. A public utility selecting a current or future test year shall present the following information: | |
| | a. A comparison of forecast data to historical period data to demonstrate the reliability and accuracy of the utility's forecast including a comparison of the prior years' forecast or budgeted data to actual data for those periods. | Benjamin Halama, Exhibit___(BCH-1), Schedule 10. |
| | b. A statement that the public utility's forecast is reasonable, reliable, and was made in good faith and that all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the commission to test the appropriateness of the forecast. | Benjamin Halama, Exhibit___(BCH-1), p. 18-19. |
| | c. A statement that the accounting treatment that has been applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred. | Benjamin Halama, Exhibit___(BCH-1), P. 19. |

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| **N.D.C.C. 49-05-04.1. Test year – Public utility rate filings. (cont.)** | 3. The public utility may update its filing for material changes as actual data becomes available up to thirty days before the hearing. Except for good cause shown, a public utility may not submit more than one updated filing before the hearing. In the absence of an updated filing by the public utility, the commission may require a public utility to update its filing when the commission staff introduces evidence that a material change has occurred. | N/A |
| | 4. A public utility may propose estimated or calculated adjustments to the selected historical or current test year for all known and measurable changes in operating results as measured in the test year. The adjustments must be made in the same context and format as the information was provided in the original filing. The adjustments may reflect material changes in plant investment, operating revenues, expenses, and capital structure if the changes occurred during the selected historical or current test year or are reasonably certain to occur subsequent to the selected test year within twelve months from the date of the rate filing. | N/A |
| | | |
| **N.D.C.C. 49-05-04.2. Rate adjustment — Federal environmental mandate costs** | 1. The commission may approve, reject, or modify a tariff filed under section 49-05-06, which provides for an adjustment of rates to recover jurisdictional capital costs and associated operating expenses incurred by a public utility to comply with federal environmental mandates on existing electricity generating stations. For purposes of this section, federal environmental mandates are limited to any requirements under the Clean Air Act, the Clean Water Act, or any other federal law or rule designed to protect the environment. | N/A |
| | | |
| **N.D.C.C. 49-05-04.3. Rate adjustment — Transmission facility costs.** | 1. The commission may approve, reject, or modify a tariff filed under section 49-05-06 which provides for an adjustment of rates to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. | N/A |

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| | | |
| **N.D.C.C. 49-05-05. Changes in tariff rates — Notice to commission — Filing fee.** | No change shall be made by any public utility in any tariffs, rates, joint rates, fares, tolls, schedules, classifications, or service which have been filed and published by any public utility, except after thirty days' notice to the commission. The notice shall state plainly the changes proposed and except for services must be accompanied by a fifty dollar filing fee. | Notice of Change in Rates for Electric Service, p. 1. |
| | | |
| **N.D.C.C. 49-05-06(2) [Interim Rates]** | 2. Notwithstanding that the commission may suspend a filing and order a hearing, a public utility may file for interim rate relief as part of its general rate increase application and filing. If interim rates are requested, the commission shall order that the interim rate schedule take effect no later than sixty days after the initial filing date and without a public hearing. The interim rate schedule must be calculated using the proposed test year cost of capital, rate base, and expenses, except that the schedule must include: | |
| | a. A rate of return on common equity for the public utility equal to that authorized by the commission in the public utility's most recent rate proceeding; | Alternative Petition for Interim Rates, p. 2-3.<br><br>10.00 percent ROE per Case No. PU-12-813, REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14), Section I.A.3, p. 9. |
| | b. Rate base or expense items the same in nature and kind as those allowed by a currently effective commission order in the public utility's most recent rate proceeding; and | Alternative Petition for Interim Rates, p. 2. |
| | c. No change in existing rate design. | Alternative Petition for Interim Rates, p. 4. |
| | 3. In ordering an interim rate schedule, the commission may require a bond to secure any projected refund required by subsection 4. The terms of the bond, including the amount and surety, are subject to the commission's approval. | N/A |

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| | 4. As ordered by the commission, the utility shall promptly refund to persons entitled thereto all interim rate amounts collected by the public utility in excess of the final rates approved by the commission plus reasonable interest at a rate to be determined by the commission. | N/A |
| | | |
| **N.D.A.C. 69-02-02-04. Application.** | An application is a proceeding seeking some right, privilege, or authorization which the commission may give under statutory or other authority administered by it. | |
| | 1. **Contents**. Applications must be in writing and must: | Notice of Change in Rates for Electric Service. |
| | a. Set forth the full name and post-office address of the applicant; | Notice of Change in Rates for Electric Service, p. 3. |
| | b. State clearly and concisely the authorization or permission sought; and | Notice of Change in Rates for Electric Service, p. 1. |
| | c. Cite by appropriate reference the statutory provision or other authority under which the commission authorization or permission is sought. | Notice of Change in Rates for Electric Service, p. 1. |
| | 2. **Number of copies**. An original and seven copies of an application must be filed. | Application Cover Letter, p. 1. |
| | 3. **Articles of incorporation or partnership agreement**. | Notice of Change in Rates for Electric Service, p. 5. |
| | a. Corporations. If the applicant is a corporation, a certified copy of its articles of incorporation must be annexed to the application. An original certificate of good standing must also be filed. | N/A |
| | b. Partnerships. If the applicant is a partnership, the partnership agreement and any fictitious name certificate must be filed. | N/A |
| | c. If the applicant's articles of incorporation or partnership agreement have already been filed with the commission in some prior proceeding, it is sufficient if this fact is stated in the application and reference is made to the case number and number of the prior proceeding. | The Company's articles of incorporation were filed in the Corporate Documents Case No. PU-09-664 on January 9, 2020. |

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| | 4. Financial statement. Whenever the commission requires the filing of a financial statement by any utility, the applicant shall file consolidated financial statements for the most recent fiscal year using generally accepted accounting principals [sic] or, if applicable, accounting standards required by federal regulatory jurisdictions. Each financial statement must include: | Benjamin Halama, Exhibit___(BCH-1), Schedule 11. |
| | a. A balance sheet of the form and style usually followed in the industry. | Benjamin Halama, Exhibit___(BCH-1), Schedule 5. |
| | b. An income statement of the form and style usually followed in the industry. | Benjamin Halama, Exhibit___(BCH-1), Schedule 6. |
| | c. If available, an independent accountant's financial opinion. | N/A |
| | d. Any other information requested by the commission. | N/A |
| | | |
| **N.D.A.C. 69-02-04-01. Notice.** | […]<br>An electric, gas, or telecommunications public utility shall provide individual customer notice as required below by billing insert, newsletter, or other appropriate method approved by the commission. The notice must indicate the place and date of the commencement of any hearing, informal hearing, or public input session that has been ordered by the commission, and that the public is invited to attend. Subject to the power of the commission to modify its contents and when applicable, the notice must include a summary sheet describing the absolute dollar and percentage impact of any proposed rate or price changes by the various classes of services offered by the utility and must include a list of the utility's business office locations where the proposed rate or price schedules and a comparison of present and proposed rates or prices can be examined by the public. The notice must also contain in bold type the following statement when applicable: The rate changes described in this notice have been requested by (specific utility). | Notice of Change in Rates for Electric Service, p. 5-6. |

| **RELEVANT FILING STATUTES AND REGULATIONS** | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| | For electric and gas utilities, individual customer notice is required for an application for approval of a rate increase, purchase or sale, merger, or acquisition filed by the utility, and applications by the utility for alternative regulation. For electric and gas utilities, the commission may require the utility to provide individual customer notice to potentially affected customers in other rate proceedings, complaint cases, advance determination of prudence cases, and fuel and purchased gas adjustment proceedings. | Notice of Change in Rates for Electric Service, p. 5-6. |
| | […]<br>The individual customer notices required by this section are separate from and in addition to any other customer notices required by law or rule, unless the commission authorizes the utility to satisfy multiple notice requirements with one notice. | Notice of Change in Rates for Electric Service, p. 5-6. |
| | | |
| **N.D.A.C. 69-09-02-01. Rates and regulations to be filed.** | 1. Schedules of rates and charges for the furnishing of electric service, and rules and regulations pertaining thereto, shall be filed with the commission by each utility. The provisions thereof shall be definite and so stated as to minimize ambiguity or the possibility of misinterpretation. The rate schedules, or the rules and regulations, shall include, together with such other information as may be deemed pertinent, the following: **[details omitted]** | Application, Volume 2; Nicholas Paluck, Exhibit___(NNP-1), Schedule 6;<br>Michael Peppin, Exhibit___(MAP-1). |
| | 2. Any proposed change in rates or charges for the furnishing of electric service, or rules and regulations pertaining thereto, shall be filed with the commission not less than thirty days prior to the effective date thereof. The filing shall include a statement indicating the reason for the proposed change, the number of customers affected, the estimated increase or decrease in annual revenue and the basis for the estimate, and the existing rate schedules or rules and regulations, if any, to be superseded. | Notice of Change in Rates for Electric Service, p. 1; Application, Volume 2.; Benjamin Halama, Exhibit___(BCH-1), p. 2-4. |

| RELEVANT FILING STATUTES AND REGULATIONS | | |
|---|---|---|
| **Statute/ Regulation** | **Required Information** | **Section and Page of Application** |
| | 3. Special contracts for the sale of electric energy to customers shall be filed with the commission showing the name and address of the customer, the point where energy is delivered, the rate to be charged, term of contract, load conditions, voltage of delivery, and other provisions of the contract. | N/A |
| | 4. Standard contract forms for the sale of electric energy for streetlighting, municipal water pumping, or other services, shall be filed with the commission showing availability, rates, and all other terms and conditions thereof. | *See* Current Electric Rate Book at Section 7. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-400-92-399**<br>**1992 ELECTRIC RATE CASE**<br>FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER<br>(12/15/92)<br>Finding 118 | Long-term incentive compensation was treated as a shareholder expense. | Benjamin Halama, Exhibit___(BCH-1), p. 72-73. Company is requesting changes to recovery of certain long-term incentive compensation costs. Greg Chamberlain, Exhibit___(GPC-1), p. 43-46.<br><br>Alternative Petition for Interim Rates, p. 2. |
| **PU-400-92-399**<br>**1992 ELECTRIC RATE CASE**<br>FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER<br>(12/15/92)<br>Findings 130 and 131 | Only organizational dues related to North Dakota electric operations were included. | Benjamin Halama, Exhibit___(BCH-1), p. 73; rate request is consistent with this decision. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section B, pg. 7; Section E, pg. 10-11 | The Company will use the principles adopted in Case No. PU-07-776 in establishing depreciation rates for use in North Dakota, including:<br>• Extend the service lives of the Sherco Generating Station, Angus C. Anson, Granite City, High Bridge, Inver Hills, and Key City;<br>• Reduce the depreciation rates for its transmission and distribution assets to effect an adjustment in the reserve balance, thereby recalibrating the balance to be more in line with theoretically calculated levels;<br>• Recover removal costs in depreciation rates for transmission and distribution based on a net present value methodology rather than on a future cost methodology (using Staff's alternative five year historical average for the purposes of this case);<br>• No continued accruals to the existing escrow account for Monticello;<br>• Use a remaining life for the Prairie Island nuclear generating plant that assumes approval of the requested life extension for this facility. | Benjamin Halama, Exhibit___(BCH-1), p. 35, 73-74; Mark Moeller, Exhibit___(MPM-1), p. 8, 23, 46.<br><br>Company is proposing to update the service lives of Sherco Units 1 and 2 to their currently-planned retirement dates. *See* Christopher Shaw, Exhibit___(CJS-1), Sec. III. |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section B, pg. 8 | Unless directed otherwise by the Commission, rate recovery -- past, present, and future -- for the removal and retirement of Company utility property will be used solely for the retirement of the Company's utility property and recognized as a regulatory liability. | Company actions have, and will comply with this directive; no new discussion necessary at this time. |

| | | |
|---|---|---|
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section B, pg. 8 | The Company will submit to the Commission the various depreciation studies and related documents that are periodically filed with the Minnesota Public Utilities Commission. Such filings include:<br>• Annual Review of Remaining Lives,<br>• Average Service Life and Vintage Group Filing (every five years),<br>• Triennial Review of Nuclear Decommissioning. | *See* Mark Moeller, Exhibit___(MPM-1).<br><br>The 2013 Remaining Lives Study was filed in Case No. PU-07-776 (11/01/13).<br><br>The 2014, 2015 and 2017 studies were filed in Case No. PU-12-813 (03/07/14, 05/27/15, and 02/21/17, respectively).[2]<br><br>The 2018 study was filed in PU-07-776 (02/21/18) and Supplemented (03/20/18).<br><br>The 2017 Transmission, Distribution and General (TD&G) Study was filed on 08/15/17 and no Case Number was issued.<br><br>The 2018 Annual TD&G Report was filed in Case No. PU-07-776 (08/08/18). .<br><br>The 2019 Annual TD&G Report was filed in Case No. PU-07-776 (8/2/19).<br><br>Minnesota 2012 – 2014 Triennial Decommissioning Accrual Filing and Supplemental Filing were submitted in Case No. PU-07-776 (12/10/12) and (03/31/14).<br><br>Minnesota 2016 – 2018 Triennial Decommissioning Accrual Filing and Supplemental Filings were submitted in Case |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| | | No. PU-07-776 (03/31/15), (04/13/16) and (04/07/17).<br><br>Minnesota 2019 - 2021 Triennial Nuclear Decommissioning Accrual filing was submitted in Case No. PU-07-776 (12/06/17), (4/6/18) |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT (12/31/08)<br>Section I, pg. 14 | The Company will remove test year expenses related to Renewable Development Fund research and development grants and disbursements. | Benjamin Halama, Exhibit___(BCH-1), p. 74. |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT (12/31/08)<br>Section J, pg. 14 | The Company will remove 50 percent of test year charitable contributions | Benjamin Halama, Exhibit___(BCH-1), p. 53-54, 74. |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT (12/31/08)<br>Section K, pg. 14 | For cost recovery purposes, incentive compensation costs are capped at 15 percent of base salary. | Benjamin Halama, Exhibit___(BCH-1), p. 74. Company is requesting recovery of certain additional incentive compensation expenses. Greg Chamberlain, Exhibit___(GPC-1), p. 45. |

[2] The 2016 Remaining Lives Study was not filed due to Regulatory Lag in Minnesota.

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section A, pg. 5 | The Company commits to keeping the Commission and its Staff informed on a timely basis of any major changes in its Resource Plan or significant legislative initiatives under consideration in another jurisdiction. | The Company has endeavored to keep the Commission and Staff informed on a timely basis throughout the Company's RTF proceedings, which are being conducted in Case Nos. PU-12-813, et al.<br><br>At the request of the Commission, the Company filed its 2020-2034 IRP with the Commission in Case No. PU-19-220 (filed 7/1/19, informal hearing 5/13/20). |

| | | |
|---|---|---|
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section A, pg. 4 | Xcel Energy agrees to provide to the Commission its Minnesota-filed Resource Plans for the integrated NSP System<br><br>The Company agrees to provide an alternative system-wide resource plan (the "North Dakota version") that strictly meets both Federal and North Dakota environmental and renewable requirements for the same time period addressed by the Minnesota Resource Plan.<br><br>Xcel Energy agrees to file the complete resource plan and updated North Dakota version on a schedule that corresponds to its overall Resource Planning cycle. | The Company filed its 2020-2034 IRP with the Commission in Case No. PU-19-220 (filed 7/1/19, informal hearing 5/13/20), along with a Supplement (06/30/20).<br><br>The Company filed its 2015 Resource Plan on in Case No. PU-15-019 (01/05/15), along with the following updates:<br>• Supplement to 2015 IRP (03/16/2015);<br>• Corrections to Appendix F of Initial Filing with MPUC (Dkt. No. E-002/RP-15-21) (05/14/15)<br>• Supplement to 2015 IRP (01/29/16)<br>• MN PUC Resource Plan Order Requiring Supplemental Filing; (Dkt. No. E-002/RP-15-21) (01/06/16)<br>• Revised Supplement to 2015 IRP filed with the MPUC (Dkt. No. E-002/RP-15-21) (02/03/16);<br>• Update as to end of Prairie Island forced outage filed with the MPUC (Dkt. No. E-002/RP-15-21) (03/04/16)<br>• Update on Calpine Acquisition filed with MPUC (Dkt. No. E-002/RP-15-21) (03/29/16)<br>• Update on Wind Generation RFP filed with MPUC (Dkt. No. E-002/RP-15-21) (09/22/16) |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| | | • MN PUC Resource Plan Order (Dkt. No. E-002/RP-15-21) (01/11/17) |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section A, pg. 6 | In this first and all future Ten Year Plans, the Company will include and describe the current five-year action plan for generation and transmission facilities and its anticipated schedule for Advance Determination of Prudence filings.<br><br>The Company agrees to file a summary of the key generating and transmission investments or purchase agreements that it intends to construct or enter into within the next five years with its annual Ten Year Plan. This summary will provide an anticipated schedule of future applications for Advance Determination of Prudence that the Company would commit to filing with the Commission. | 2013 10-Year Plan filed in Case No. PU-13-790 (09/13/13);<br><br>2014 10 Year Plan filed in Case No. 14-517 (07/01/14);<br><br>2016 10-Year Plan filed in Case No. 16-489 (07/01/16);<br><br>2018 10-Year Plan filed in Case No. PU-18-259 (07/18/18); and<br><br>2020 10-Year Plan filed in Case No. PU-20-304 (07/01/20).<br><br>Note: statute was changed from annual to biennial in 2013 |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section A, pg. 5 | The Company agrees to meet with the Commission and Staff as necessary to conduct updates on its resource planning efforts and decisions, and discuss the Ten Year Plan filed in that year. | The Company has met extensively with the Commission and with Staff in the RTF proceeding conducted in Case Nos. PU-12-813, et al. |

| | | |
|---|---|---|
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section B, pg. 6 | The Company agrees to seek an Advance Determination of Prudence finding from the Commission for all proposed new construction, rehabilitation, or acquisition of an energy conversion facility, renewable energy facility, transmission facility or proposed energy purchase in which: 1) the Company proposes to allocate all or part of the related costs to the North Dakota jurisdiction for recovery in electric rates; and 2) the capacity of the generation facility or purchase is at least 50 MW; and/or the length of the transmission facility is at least 50 miles long. Also, the Company will identify its proposed cost-allocation methodology in the ADP petition as an item for which a determination of prudence by the Commission is requested. | Greg Chamberlain, Exhibit___(GPC-1), p. 3-4.<br><br>Since the last rate case filing, ADPs have been filed as necessary for:<br>• CapX2020 (PU-09-678);<br>• Prairie Island (PU-10-127);<br>• Prairie Rose Wind 12-059;<br>• Manitoba Hydro (PU-12-070);<br>• Natural Gas Peaking Units (PU-13-194 & 195);<br>• Courtenay, Odell & Pleasant Valley Wind Projects (PU-13-706, 707 & 708);<br>• Border Winds Project (PU-13-742);<br>• 187 MW Solar RFP (PU-14-810);<br>• Aurora Solar (PU-15-095);<br>• Mankato Energy Center (PU-15-096);<br>• Courtenay Wind (PU-15-181);<br>• 1,550 MW Wind (PU-17-120);<br>• 3 Biomass PPAs (PU-17-270, 271 and 322);<br>• Dakota Range Wind (PU-17-372);<br>• Mankato Energy Center (PU-18-403);<br>• Dakota Range III (PU-18-430);<br>• Mower County Wind (PU-19-310); and<br>• Repowered Wind Projects (PU-20-425). |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section B, pg. 7 | To the extent the ADP processes outlined in Case No. 07-776 reveal continued concern with individual resource decisions or cost assignments to jurisdictions, the Company commits to working with Commission Staff on alternative resource evaluation approaches.<br><br>When appropriate, the Company will advocate for cost recovery statutes that directly assign costs and benefits of any mandated expenditures to the jurisdiction imposing the mandate. | Greg Chamberlain, Exhibit___(GPC-1), p. 25-27.<br><br>The Company's RTF proceeding conducted in Case Nos. PU-12-813, et al., have addressed this topic in depth. |
| **PU-07-776**<br>**2007 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/31/08)<br>Section B, pg. 7 | The Company will reflect its North Dakota depreciation rates in its annual North Dakota earnings reports. | The Company has reflected its approved North Dakota depreciation rates in its earnings reports. *See, e.g.,* 2019 earnings report filed in Case No. PU-20-185. |
| **PU-10-657, PU-11-055, and PU-11-557**<br>**ELECTRIC RATE CASE**<br>AMENDED SETTLEMENT AGREEMENT<br>(12/23/11)<br>Section IV. A., pg. 12<br>ORDER ON SETTLEMENT<br>(02/29/12) | Xcel Energy will install 25 Intelliteam switches on its Fargo, North Dakota distribution system. The switches will be in service by year-end 2012. | 25 Intelliteam switches were installed. *See* Kelly Bloch, Exhibit___(KAB-1), p. 19.<br><br>In Case No. PU-12-813, Revised Second Amended Settlement Agreement at VII.A.1, the Company agreed to repurpose the remaining funding from the Company's 2012 Intelliteam roll-out to extend the 500 MCM removal project one additional year and expand the scope to approximately $400,000 per year from 2013-2015).<br><br>Expenditures for the 500 MCM project for 2013 to 2015 totaled $1.6 million. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-10-657, PU-11-055, and PU-11-557 ELECTRIC RATE CASE** AMENDED SETTLEMENT AGREEMENT (12/23/11) Section IV. B., pg. 13 ORDER ON SETTLEMENT (02/29/12) | Beginning in 2012, the Company will increase its operating expense budget to supplement its vegetation management (e.g. tree pruning) activities in North Dakota by adding an additional vegetation management crew. | Kelly Bloch, Exhibit___(KAB-1), p. 28-30. Benjamin Halama, Exhibit___(BCH-1), p. 14. |
| **PU-10-657, PU-11-055, and PU-11-557 ELECTRIC RATE CASE** AMENDED SETTLEMENT AGREEMENT (12/23/11) Section IV. D., pg 13 ORDER ON SETTLEMENT (02/29/12) | The Company will hire, in 2012, an additional electrical engineer to be based in Fargo, North Dakota. | The additional electrical engineer was hired. *See* Kelly Bloch, Exhibit___(KAB-1), p. 19. |
| **PU-10-657, PU-11-055, and PU-11-557 ELECTRIC RATE CASE** AMENDED SETTLEMENT AGREEMENT (12/23/11) Section I.C., pg. 7; Section IV. F., pgs. 15–16 ORDER ON SETTLEMENT (02/29/12) Order Point 2<br><br>*SEE ALSO* ORDER ON SETTLEMENT (12/12/12) | Beginning January 1, 2012, Xcel Energy agrees to provide the Commission the following reliability information for calendar years 2012 through 2014:<br>• On an event by event basis, email notification of each sustained (duration of five minutes or more) feeder level outage. Additional notifications and information will be provided for the most significant events as appropriate;<br>• On a quarterly basis, a report showing all outages due to underground cable failure and cable replacements made under the Company's underground cable replacement policy;<br>• On an annual basis, a summary of the key elements of the Company's most current reliability expenditure plan and budget for North Dakota;<br>• On an annual basis, storm-normalized SAIFI and CAIDI results for the Company's North Dakota operations for each of the past five years, as well as a report of the same information for each of the largest five substations; | Email notifications were sent when sustained outages occurred.<br><br>*See* Case No. PU-12-813, REVISED SECOND AMENDED SETTLEMENT AGREEMENT at VII.A.3 (Suspension of practice of providing feeder outage notifications as they occur, and quarterly underground cable failure summary reports, until further Commission notice. The Company has continued to provide the Commission notice of major outages and other events as appropriate.). |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| | • On an annual basis, the top ten causes of outage events (with and without storm outages) for each of the past three years, and the top ten causes of all customer-minutes out (CMO) for each of the past three years (again, with and without storm outages);<br>• On an annual basis, the number of customers experiencing multiple service interruptions, including the number of customers experiencing 4, 5, and 6 or more outages during the previous calendar year. Storm and public damage-related outages will be excluded from the information. | |
| **PU-10-657, PU-11-055, and PU-11-557**<br>**ELECTRIC RATE CASE**<br>AMENDED SETTLEMENT AGREEMENT (12/23/11)<br>Section I.C., pgs. 6-7, Section IV. E., pgs. 14-15<br>ORDER ON SETTLEMENT (02/29/12)<br>Order Point 2<br>Order Point 3<br><br>*SEE ALSO* ORDER ON SETTLEMENT (12/12/12) | The parties agree to jointly develop and file, within 90 days of the Order in this proceeding, recommendations regarding a reliability "service quality plan" to include a focus on localized reliability performance. The development of this plan and recommendations will be guided by the following principles:<br>• Industry standard performance indicators (SAIFI, CAIDI, and SAIDI) will be considered along with other metrics relating to "customer experience" level (i.e., customers with multiple outages, customer satisfaction survey scores, etc.).<br>• Performance targets will be constructed as ranges to acknowledge normal levels of performance variability and create more meaningful targets.<br>• Performance incentives will be symmetrical, such that any financial impact would be based on both above-target and below-target performance. The duration of the plan term and other plan exceptions will be clearly defined to allow for flexibility in the operation, review, and amendment of the plan.<br>• The Company's ability to seek rate recovery of its prudent investments and operating costs will be maintained during the term of the plan. | Proposed Reliability Performance Plan filed in Case Nos. 10-657, 11-055 and 11-557 (06/04/12).<br><br>Settlement Agreement & Order Approving Reliability Performance Plan (along w/DOE Settlement Payments 1-5) was filed on 12/12/12. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14)<br>Preliminary Statement, pgs 3–5; Section I.A.1 | Multi-year (4-yrs) plus provision to develop a resource framework mechanism with a hard deadline otherwise company will face adverse financial impacts set out in Section II.A. | The Company's RTF proceeding conducted in Case Nos. PU-12-813, et al., have addressed this topic in depth. |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14)<br>Preliminary Statement at 5. | If parties are unable to meet the deadlines this settlement will result in adverse financial impacts on the Company as set forth in Section 2. | The Company's RTF proceeding conducted in Case Nos. PU-12-813, et al., have addressed this topic in depth. |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14)<br>Section I.A.3, pg. 9 | The Parties also agree that a 10.00 percent ROE will be used for purposes of determining interim rates in the Company's next electric rate application. | Alternative Petition for Interim Rates, p. 2-3. |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14)<br>Section II.A, pgs. 12-17 | Implementation of North Dakota Energy Policy for resource decisions via development of a comprehensive framework by June 30, 2015. Any extension must be filed by deadline or face financial implications including removal of costs from FCR and disallowance of project costs such as Pleasant Valley Wind. | The Company's RTF proceeding conducted in Case Nos. PU-12-813, et al., have addressed this topic in depth.<br><br>90-day extension granted by Commission order in Case No. PU-12-813 (6/17/15). Negotiated Agreement superseding this provision filed 9/30/15, First Revised Negotiated Agreement filed 2/22/16, approved by Commission 3/9/16. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>SETTLEMENT AGREEMENT<br>(12/13/13)<br>Section II.C, pg. 18 | For purposes of allocating production and transmission costs among state jurisdictions, the Parties agree to the continued use of the average 12-month Coincident Peak (CP) demand methodology for the purposes of this Comprehensive Settlement. Further, the jurisdictional allocation for rate rider calculations will be made using the methodology applied in this case with allocation factors updated to reflect current circumstances. The Company will use its 2013 test year forecast or some other suitable test year in this case to determine jurisdictional costs using 12 CP, 1 CP and other methodologies of interest and submit its comparative findings to the Commission by July 1, 2014. The information may be used to inform the evidentiary record in the Company's next electric rate application. | Benjamin Halama, Exhibit___(BCH-1), p. 46-47; Janell Marks, Exhibit___(JEM-1), 37-40. |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(2/25/14)<br>Section II.C pgs. 18-19 | The Parties agree that a study shall be performed to analyze the contribution of the Company's North Dakota jurisdiction toward the Company's overall system-wide production and transmission costs, and the available demand allocation methodologies which may be implemented to reflect such cost causation. The costs of using an independent third-party will be paid by the Company. The Parties agree to use deferred accounting to recover these costs as a rate case expense in the Company's next rate case. | Demand Allocator Study dated April 2015 was filed in Case No. PU-12-813 (04/27/15). |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section II.E, pg. 21 | The Parties agree that the Company's proposal to construct Black Dog Unit 6 and Red River Valley Units 1 and 2 under the flexible, phased in approach described in the Company's Application is a cost-effective and prudent approach to meet forecasted capacity needs of the Company in the 2017 to 2019 time-frame... | Black Dog Unit 6 was placed in service in 2018. *See* Mark Moeller, Exhibit___(MPM-1), p. 11-12.<br><br>The Company sought a certificate of public convenience and necessity for Red River Valley in Case No. PU-13-195; however the Application was dismissed without prejudice by Order (08/20/14). |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section II.E pg. 21 | In the event the Company chooses to move forward with a resource acquisition other than Black Dog Unit 6 or Red River Valley Unit 1 or Red River Valley Unit 2 to meet its 2017-2019 capacity need, it shall file an application for an Advanced Determination of Prudence for such other resource acquisition(s). In the event that the Company constructs and owns Red River Valley Unit 1 or Red River Valley Unit 2 to meet its identified 2017-2019 resource needs, the Company's commitment in Section Il.B of the Revised Second Amended Settlement shall be deemed to have been satisfied. | The Company sought a certificate of public convenience and necessity for Red River Valley in Case No. PU-13-195; however the Application was dismissed without prejudice by Order (08/20/14).<br><br>The Company sought ADPs for Aurora Solar (Case No. PU-15-95; ADP denied by Order 09/16/15) and Mankato Energy Center II (Case No. PU-15-96; ADP dismissed without prejudice 03/23/16). *See* Christopher Shaw, Exhibit___(CJS-1), p. 37. |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section II.F pgs. 21 | Agree that the Company's proposal to construct and own the Border Winds Project and to purchase the output of the Courtenay Project as described in the Wind Cases enjoy a rebuttable presumption of prudence as resource additions located within North Dakota per N.D.C.C. § 49-05-16. The Parties further agree that the record in the Wind Cases does not support a rebuttal to the presumption of prudence. Therefore, the Parties agree that the Border Winds Project and the Courtenay Project are prudent resource additions to the Company's integrated system and meet the standards for advanced determinations of prudence from the Commission. The disposition of the Odell and Pleasant Valley Projects are intended by the Parties to be addressed in the Negotiated Agreement or as provided for in Section II.A of this Revised Second Amended Settlement. | Company proposes to move costs for Border Winds, Courtenay, Foxtail, Blazing Star I and II, Lake Benton, and Crowned Ridge to base rates in this Case. Benjamin Halama, Exhibit___(BCH-1), 63.<br><br>Border Winds, Odell & Pleasant Valley filed via Company's Ten Year Plan (PU-16-489); Courtenay CPCN & ADP filed via PU-15-174, 175, 181 & 183. Granted via Order (08/24/15). |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14)<br>Section III.A. at p. 22-23 | The Parties agree to extend the Company's amortization period for unrecognized pension costs reflecting, among other things, costs associated with the 2008 market downturn. The Company's pension costs are determined under the Aggregate Cost Method, a pension funding method based on guidelines provided by the Internal Revenue Service. The method does not comply with SFAS 87, but is allowed as a permitted exception under SFAS 71 since it has received regulatory approval. The Parties agree that the Company will move from the current "percent of compensation" based amortization period of approximately 10 years to a 20 year amortization period. The appropriate ratemaking treatment will include a return on the unamortized balance. | Benjamin Halama, Exhibit___(BCH-1), p. 75. |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14)<br>Section III.B pg. 22 | The Parties agree that for purposes of determining the overall test year revenue requirement and future regulatory reporting, Annual Incentive Plan costs above 15 percent of base pay will be excluded. | Benjamin Halama, Exhibit___(BCH-1), p. 74. The Company is requesting recovery of certain additional incentive compensation expenses. Greg Chamberlain, Exhibit___(GPC-1), p. 45. |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT (02/25/14)<br>Section III.C pg. 23 | The Parties agree that for purposes of determining the overall revenue requirement and annual regulatory reporting during the 2013-2016 term of the Agreement, donations to state and local economic development entities and charitable contributions will be excluded. | The Company is proposing to include 50 percent of corporate charitable contributions benefiting the State of North Dakota in the test year. *See* Benjamin Halama, Exhibit___(BCH-1), p. 53-54. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section III.D, pg. 23 | In the Settlement Agreement resolving a previous rate application (Case No. PU-07-776), the Parties agreed that the Company would pass to customers 85 percent of the margins realized from wholesale electricity sales from Company-owned (asset-based) generation. The Company currently passes 100 percent of the jurisdictional allocation of these margins to its Minnesota and South Dakota customers. The Parties agree that the Company will, beginning January 1, 2014, pass through 100 percent of wholesale asset-based margins to North Dakota customers as well. | Benjamin Halama, Exhibit___(BCH-1), p. 33-34, 75. |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section III.E, pg. 24 | Agreed to increase the amortization period for various non-recurring expense items from the Company's initially filed three year period to a four-year period. This is consistent with the four-year term of the Rate Plan. | N/A |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section IV.A, pg. 25 | The Parties agree to a customer class revenue increase apportionment reflecting rate percentage changes (by customer class) that are consistent with the Company's originally proposed class revenue increases, as shown on Attachment F. This apportionment reflects rate percentage changes by customer class that are consistent with the Company's originally proposed class revenue allocation, as shown on the attachment. | N/A |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section IV.B pg. 26 | The Parties believe it would be prudent to make significant steps toward better matching of the fixed costs of providing electric service with fixed rates. … The Parties agree, therefore, to replace the four distinct Customer Charges for non-time of day residential electric service (regular overhead, overhead space heating, regular underground, and underground space heating) with a single, common Customer Charge of $14.00. The Small General Service Customer Charge will be set at $16.00. | Company proposes a moderate increase to move Residential customer charges to cost. Nicholas Paluck, Exhibit___(NNP-1), p. 6-7.<br><br>Application, Volume 2. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section IV.C pg. 27 | The Parties agree to eliminate the $5 charge for responding to customer requests for account history. | Compliance filing made in Case No. PU-12-813 (3/10/14). |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section IV.D pg. 27 | By December 31, 2014, the Company commits to submitting to the Commission either a pilot [time-of-day ("TOD")] tariff or a recommendation regarding an appropriate path for improving a residential TOD offering in North Dakota. | Compliance filing made in Case No. PU-12-813 (12/31/14). |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section V.A pgs. 27-28 | As a condition of this Revised Second Amended Settlement, the Parties agree that the Company will pass 100 percent of North Dakota jurisdictional net REC proceeds to North Dakota customers for all sales on and after January 1, 2014 | 2020 Fuel Clause Adjustment filing in Case No. PU-20-012 (06/30/20), pp. 2-3. |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section V.A pgs. 27-28 | Given that the current market for hydro and biomass RECs is minimal since these types of RECs are not as viable for voluntary purchasers, the Company will investigate the potential for establishing a framework for transacting "inter-jurisdictional" REC sales whereby non-marketable RECs allocated to North Dakota could be transferred - or "sold" - to the Company's NSP REC portfolio for purposes of meeting the renewable energy standards or objectives of other jurisdictions served by the Company, subject to approval of the relevant jurisdictions. The proceeds from these transactions would be passed on to North Dakota customers like any other REC sale. The Company commits, as a condition of this Settlement, to file a report with the Commission no later than December 31, 2014 detailing its findings and recommendations for such a process. | Compliance filing made in Case No. PU-12-813 (12/22/14). |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section VII.B pgs. 30-31 | NSP will footnote the North Dakota portion of its Asset Retirement Obligation in its annual report of regulated earnings. Will also notify the PSC of any new depreciable life studies or revisions filed with MPUC. The depreciation lives and rates presented in the Rate Case will be the ones in effect upon approval of this Revised Second Amended Settlement. | The Company has complied with this requirement. *See*, Case No. PU-20-185, Docket No. 3 at p. 69. |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section VII.C pg. 31 | The Parties agree that the Company will submit to the Commission, no later than the date of its next general rate application, an updated and improved North Dakota Electric Rate Book. The new revision will include a thorough review of all tariffs and general rules of service and reflect language and/or format enhancements that will improve readability, remove unnecessary phrases or sections, and ensure the terminology is up-to-date and understandable. The Company will work with Staff throughout the project to ensure the revisions meet the needs of North Dakota customers, the Company, developers, and regulators. | Nicholas Paluck, Exhibit___(NNP-1), p. 15-18; Application, Volume 2. The Company proposes tariff revisions consistent with this requirement. |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE**<br>REVISED SECOND AMENDED SETTLEMENT AGREEMENT<br>(02/25/14)<br>Section VII.D pgs. 31-32 | During the Rate Case, Staff and the Commission expressed concerns about the Company's difficulty in producing North Dakota jurisdictional financial data on a monthly or year-to-date basis. The Parties recognize the need to be able to timely produce and review updates of actual expenses, test year expenses, rate base, and overall revenue requirements, particularly during discovery process. Thus, the Parties agree that, prior to the next general rate application, the Company will develop a jurisdictional financial system that can be used to update test year forecasts with actual data and/or revised revenue, expense, and capital expenditure forecasts. The tool will also be able to accommodate assumption changes for purposes of modeling different test year input scenarios. | Company's investment in a new SAP General Ledger (GL) system allows the Company to comply with this requirement. *See* Mark Moeller, Exhibit___(MPM-1), p. 12-13. |

| Rate Case Compliance Items | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813, et al.**<br>**2012 Electric Rate Case,** Various Case ADPs<br>First Revised Negotiated Agreement (09/22/16)<br><br>Order Approving Settlement (03/09/16)<br>Section III, Attachment A | Designating certain resources to be excluded from the North Dakota Fuel Cost Rider.<br><br>Exclusion of 15 C-BED projects and two small solar PPAs under the First Revised Negotiated Agreement will decrease overall electric revenues by approximately $1.6 million in 2016 and a total of approximately $19 million through 2030. Pts. 4-5: Approval of ADPs for Pleasant Valley and Odell. | Benjamin Halama, Exhibit___(BCH-1), p. 17.<br><br>2020 Fuel Clause Adjustment filing in Case No. PU-20-012 (06/30/20), p. 4. |
| **PU-12-813, et al.**<br>**2012 Electric Rate Case,** Various Case ADPs<br>First Revised Negotiated Agreement (09/22/16)<br><br>Order Approving Settlement (03/09/16)<br>Section IV | The Parties agree that the Company, in consultation and collaboration with the Commission and its Staff, will propose a long-term RTF which shall address the Company's long-term plans for addressing divergent state energy policies. The Company must file the proposed RTF with the Commission no later than January 1, 2017with the expectation that the RTF, if approved by the Commission, will be implemented on January 1, 2018. Mutual agreement between the Company and Staff is desired but not a prerequisite to the Company making the filing contemplated by this paragraph. | The Company's RTF proceeding conducted in Case Nos. PU-12-813, et al., have addressed this topic in depth. |
| **PU-12-813, et al.**<br>**2012 Electric Rate Case,** Various Case ADPs<br>First Revised Negotiated Agreement (09/22/16)<br><br>Order Approving Settlement (03/09/16)<br>Section V.A | Rate Case Moratorium extended to Jan. 1, 2018. | Greg Chamberlain, Exhibit___(GPC-1), p. 4-7. |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE,** VARIOUS CASE ADPS<br>FIRST REVISED NEGOTIATED AGREEMENT (09/22/16)<br><br>ORDER APPROVING SETTLEMENT (03/09/16)<br>Section V.A | To ensure that rates remain just and reasonable during 2017, in the event that the Company's annual weather-normalized earnings exceed a 10.25 percent return on equity during 2017, the Company will refund to customers one hundred percent (100 percent) of any weather-normalized revenue associated with the excess earnings | Greg Chamberlain, Exhibit___(GPC-1), p. 13-14.<br><br>Compliance filing made in Case No. PU-12-813 (06/07/18). |
| **PU-12-813, et al.**<br>**2012 ELECTRIC RATE CASE,** VARIOUS CASE ADPS<br>FIRST REVISED NEGOTIATED AGREEMENT (09/22/16)<br><br>ORDER APPROVING SETTLEMENT (03/09/16)<br>Section V.D | The Parties agree that the conclusions of the Allocator Study filed with the Commission on April 27, 2015 support the continued use of the 12 CP jurisdictional allocation method. To that end, this Agreement establishes a rebuttable presumption that the 12 CP jurisdictional allocation method is appropriate for allocating applicable system costs between North Dakota, South Dakota and Minnesota. In the event that circumstances have sufficiently changed such that Staff believes it is appropriate to rebut the rebuttable presumption established in this paragraph: 1) Staff will notify NSP of its intentions as early as possible; and 2) Staff will work in good faith with NSP to reach agreement on an appropriate allocation methodology in light of the rebuttable presumption established in this paragraph. The provisions of this paragraph expire on December 31, 2025. | Benjamin Halama, Exhibit___(BCH-1), p. 46-47; Janell Marks, Exhibit___(JEM-1), 37-40. |
| **PU-12-813, et al**<br>**2012 ELECTRIC RATE CASE**<br><br>ORDER ON SETTLEMENT (09/06/17)<br>ORDER PT. 2, Settlement Terms Pt. A | NSP shall file a compliance tariff with the $50 bill credit for "Customers Experiencing Multiple Interruptions" (CEMI) within 10 days showing the credit is available for the calendar year 2017.<br>Parties further agree to: 1. extend the CEMI credit program one year, to include 2017; 2. maintain the financial incentive in 2017 to achieve a North Dakota SAIDI result below 57 minutes; 3. continue the current format for the Company to report reliability performance in its 2017 Annual Report; and 4. revisit further extension of the RPP and/or CEMI credits into 2018 after the Company reports its 2017 reliability results to the Commission. | Compliance tariff filed in Case No. PU-12-813 (09/14/17). |

| RATE CASE COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-12-813, et al**<br>**2012 ELECTRIC RATE CASE**<br><br>APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT FRAMEWORK TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES (1/3/17)<br>Sec. VIII, p. 59 | The Company also commits to cross-filing all comments and testimony filed in the respective state [RTF] cases/dockets to ensure transparency of the information gathered in the other jurisdiction. | Greg Chamberlain, Exhibit___(GPC-1), p. 25-27.<br>*See, e.g.,* Compliance filing in Case No. PU-12-813 (03/13/17). |
| **PU-12-813, et al**<br>**2012 ELECTRIC RATE CASE**<br><br>APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT FRAMEWORK TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES – CHANDARANA REBUTTAL TESTIMONY (12/8/16)<br>Sec. IV.A, p. 14 | Company commits to seeking Commission agreement for initial power contract terms before seeking FERC approval—i.e., the Company will first seek NDPSC approval for any transactions that may fall within FERC's jurisdiction | The Company seeks Advance Determinations of Prudence from the Commission prior to seeking FERC approval under Section 203 of the Federal Power Act, 16 U.S.C. § 824b. |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-07-774**<br>**Accounting for Nuclear Refueling Costs**<br>ORDER CHANGING ACCOUNTING TREATMENT (02/13/08) | Northern States Power Company shall amortize nuclear refueling costs over the life of the installed fuel. | Benjamin Halama, Exhibit___(BCH-1), p. 73. |
| **PU-08-171**<br>**DEMAND SIDE MGMT & COST RECOVERY TARIFF**<br>ORDER (11/05/2008)<br>Order Point 2 | NSP is authorized to record expenditures to further promote its existing Savers Switch and Peak & Energy Control Service load management programs in a deferred account for amortization in NSP's next general rate case. The amount deferred may not exceed $266,904 per year. | This program ended in 2018 and with all costs fully amortized and recovered. |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-08-908 and PU-08-910**<br>**Merricourt Wind Project ADP and CPCN**<br>ORDER ON APPLICATION FOR ADP AND CPCN<br>(08/12/09)<br>Order Point 4 | NSP will report to the extent possible, as part of its annual 10-year plan, all reductions in the energy produced at its base load generation units that would not have occurred except for the existence of wind generation. The report will include the time of event, length of the event, base load plant affected and the amount of energy not produced at the base load plant during the event. | 2020 10-Year Plan filed in Case No. PU-20-304 (07/01/20), p. 19-21.<br><br>Filed with prior 10-Year Plans in Case Nos. PU-11-385 (06/30/11), PU-12- 448 (06/29/12), PU-14-517 (07/01/14); PU-16-489 (07/01/16) and PU-18-259 (07/02/18).<br><br>Notice of cancellation was submitted in Case Nos PU-08-908 and PU-08-910 on April 8, 2011. |
| **PU-08-908 and PU-08-910**<br>**Merricourt Wind Project ADP and CPCN**<br>ORDER ON APPLICATION FOR ADP AND CPCN<br>(08/12/09)<br>Order Point 5 | NSP will report, as part of its next 10-year plan, on the impacts and costs associated with taking coal plant production up and down to accommodate wind resources during off peak hours. | 2020 10-Year Plan filed in Case No. PU-20-304 (07/01/20), p. 19-21.<br><br>Filed with prior 10-Year Plans in Case Nos. PU-11-385 (06/30/11), PU-12- 448 (06/29/12), PU-14-517 (07/01/14); PU-16-489 (07/01/16) and PU-18-259 (07/02/18).<br><br>Notice of cancellation was submitted in Case Nos PU-08-908 and PU-08-910 on April 8, 2011. |
| **PU-10-19**<br>ORDER<br>(09/08/10)<br>Order Point 5 | NSP shall file an annual report with the Commission documenting the results of its REC sales. This report can be included as a part of its annual progress reporting requirement toward meeting the renewable energy and recycled energy objective as required under North Dakota Century Code Section 49-02-34. | Annual reports were filed in Case Nos:<br>▪ PU-13-508 (06/26/13);<br>▪ PU-14-524 (06/30/14);<br>▪ PU-15-475 (06/30/15);<br>▪ PU-17-060 (06/30/16);<br>▪ PU-17-274 (06/30/17);<br>▪ PU-18-221 (06/29/18);<br>▪ PU-19-223 (06/25/19); and<br>▪ PU-20-285 (06/26/20). |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-14-810**<br>**ADP 187 MW SOLAR ENERGY PORTFOLIO**<br>FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (06/17/15) | ND PSC denied application noting the Solar Portfolio does not merit an ADP and ordered that NSP shall not recover costs through the ND FCR without specific Commission approval. | Company requests in this rate case to recover these PPA costs in the FCR. Christopher Shaw, Exhibit___(CJS-1), Sec. VI. |
| **PU-15-174, et al.**<br>**COURTENAY WIND ADP/CPCN**<br>FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (08/26/15) | Approval of the Courtenay Wind ADP and development of project. NSP agrees and is able to comply with the terms, conditions, and modifications of Certificate of Site Compatibility Number 36. | Company has complied with Certificate of Site Compatibility Number 36. |
| **PU-15-095**<br>**ADP FOR 100MW AURORA SOLAR**<br>FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (09/16/15) | ADP denied because it is not a least-cost resource. NSP shall not recover costs associated with the Geronimo Solar PPA through its North Dakota Fuel Clause Rider without specific approval of the Commission. | Company is not making any request with regard to Aurora Solar in this rate case. |
| **PU-17-490**<br>**TCJA**<br>ORDER INITIATING INVESTIGATION (01/10/18) | An investigation is initiated to determine the effect of the Tax Reform signed by President Trump on Dec. 22, 2017 beginning Jan. 1, 2017 by applying regulatory accounting treatment, use of regulatory assets and liability accounts for Commission consideration. Submit to the Commission by 2-15-18 the impacts with supporting calculations in comments regarding the appropriate regulatory accounting treatment. | Compliance filing in Case No. PU-17-490 (02/15/18).<br><br>Greg Chamberlain, Exhibit___(GPC-1), p. 12-15; Benjamin Halama, Exhibit___(BCH-1), p. 21, 27, 35-36. |
| **PU-15-096**<br>**MANKATO ENERGY CENTER ADP** | Dismissed without prejudice NSP's ADP application. | Company requests in this rate case to recover the PPA costs in the FCR. Christopher Shaw, Exhibit___(CJS-1), Sec. IV. |
| **PU-16-458**<br>**2015 PPA COSTS** | Commission reviewed NSP's annual list of new PPAs less than 50 MW and ordered NSP to exclude cost of School Sisters of Notre Dame solar facility from Fuel Cost Adjustment Rider because it is not least cost. | The Company does not make any request with regard to the School Sisters of Notre Dame in this rate case. |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-18-155**<br>**Federal Tax Reform Effects – Electric Utility Rates**<br>ORDER<br>(12/21/18) | NSP shall file, within 30 days, a plan detailing refund allocations, calculations, and the process for a $9,763,400 refund; and shall implement the refund within 90 days of this Order. NSP shall continue to apply the appropriate regulatory accounting treatment, including the use of regulatory assets and liability accounts, to record the impact of the TCJA. | Benjamin Halama, Exhibit___(BCH-1), p. 36-39.<br><br>The Company submitted a refund plan on Jan 17, 2019 in Case No. PU-18-155.<br><br>The Company completed the refund and submitted a compliance filing on 04/23/19 in Case No. PU-18-155. |
| **PU-18-155**<br>**Federal Tax Reform Effects – Electric Utility Rates**<br>ORDER ON SETTLEMENT<br>(2/6/19)<br>Sec. II.A, pg. 4 | The refund of [$9,763,400] will be made by the Company in a single payment following approval of this Agreement by the Commission. The refund of the 2018 Amount will be allocated to customer classes based on each class' share of the Commission's last-approved revenue allocation. The resulting class allocation of the refund is provided in Attachment A to this Settlement Agreement. The Company will make a compliance filing within 30 days of the Commission Order approving this Agreement detailing the calculations that will be used to determine individual customer refunds. | The Company completed the refund and submitted a compliance filing on 04/23/19 in Case No. PU-18-155. |
| **PU-18-155**<br>**Federal Tax Reform Effects – Electric Utility Rates**<br>ORDER ON SETTLEMENT<br>(2/6/19)<br>Sec. II.B.1, pg. 5 | In lieu of the Company making additional TCJA-related refunds in subsequent years beyond 2018, the Company agrees to a rate case moratorium for two years (2019 and 2020, hereinafter referred to as the Moratorium Period). More specifically, the Company may not file another general rate case prior to November 2020, so that new base rates (including interim rates) may not be effective prior to January 1,2021. | Greg Chamberlain, Exhibit___(GPC-1), p. 6-7. |
| **PU-18-155**<br>**Federal Tax Reform Effects – Electric Utility Rates**<br>ORDER ON SETTLEMENT<br>(2/6/19)<br>Sec. II.B.1, pgs. 5-6 | In the Company's next general rate case, the Test Year costs of service will reflect the impacts of the TCJA. The Parties acknowledge that for the purposes of the Company's books and records, as well as the next general rate case, excess plant-related Accumulated Deferred Income Taxes (ADIT) and the excess Net Operating Loss (NOL) ADIT will be amortized over the average rate assumption method (ARAM) lives, and excess non-plant-related ADIT will be amortized over periods ranging from five years or fifteen years, each commencing January 1, 2018. | Greg Chamberlain, Exhibit___(GPC-1), p. 12-15; Benjamin Halama, Exhibit___(BCH-1), p. 27-28, 35-36, 57; Test Year Work Papers, Volume 3, Section III Rate Base (Plant), Tab P2-3. |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-18-155 Federal Tax Reform Effects – Electric Utility Rates** ORDER ON SETTLEMENT (2/6/19) Sec. II.B.2, pg. 6 | [T]he Parties agree that Xcel Energy's existing Renewable Energy Rider (RER) will be expanded to include renewable energy resources located outside of North Dakota for which the Company has received an ADP from the Commission. | Order approving updated RER rate in Case No. PU-19-329 (02/19/20). |
| **PU-18-155 Federal Tax Reform Effects – Electric Utility Rates** ORDER ON SETTLEMENT (2/6/19) Sec. II.B.3, pg. 7 | [I]n the event the Company's annual weather normalized earnings during any of the fiscal years during the Moratorium Period exceed an ROE of 9.85 percent (40 basis points below the current Commission-authorized ROE), the Company will refund to customers 100 percent of the weather-normalized revenue contributing to the excess earnings. The earnings sharing framework is asymmetrical; customers will not be charged for weather-normalized earnings below 9.85 percent. Earnings sharing refunds will be executed in July of the following year. | Greg Chamberlain, Exhibit___(GPC-1), p. 13-15. |
| **PU-18-155 Federal Tax Reform Effects – Electric Utility Rates** ORDER ON SETTLEMENT (2/6/19) Sec. II.B.4, pgs. 7-8 | The provisions of Sections II.B.l, II.B.2, and II.B.3 of this Settlement Agreement are expressly subject to the Commission granting the ADPs requested for the 1,550 MW Wind Portfolio (PU-17-120) and Dakota Range Wind (PU-17-372). In the event that the Commission does not grant the ADPs requested in the Pending ADP Cases within 90 days of the hearing in those dockets, the Company is free to file a rate case at whatever time it chooses; provided, however, that in the event that the Company does not file a rate case at any time before the Rate Moratorium Period ends, the Company will refund the 2018 Amount within 120 days after the close of each Rate Moratorium year. | The ADPs were approved pursuant to a Settlement Agreement approved Order on Settlement in Cases No. PU-17-120 and PU-17-372 (12/06/18). |
| **PU-18-155 Federal Tax Reform Effects – Electric Utility Rates** ORDER ON SETTLEMENT (02/06/19) Sec. II.B.4, pg. 8 | In the event that the Company files a rate case, the test year will reflect the impacts of the TCJA on its cost of service. | Benjamin Halama, Exhibit___(BCH-1), p. 27, 35-36, 57; Test Year Work Papers, Volume 3, Section III Rate Base (Plant), Tab P2-3. |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-10-127**<br>**Advance Prudence – Prairie Island**<br>ORDER<br>(11/28/12) | ADP granted for replacement of Unit 2 steam generator at Prairie Island Nuclear Generating Plant. | N/A |
| **PU-12-59**<br>**Advance Prudence – Prairie Rose Wind**<br>ORDER<br>(12/21/12) | ADP for 200 MW Prairie Rose/Geronimo Wind denied because it was filed after committing to the resource addition and thus was untimely. | N/A |
| **PU-12-70**<br>**Advance Prudence – Manitoba Hydro**<br>ORDER<br>(08/01/12) | ADP granted for three PPAs with the Manitoba Hydro Electric Board, which "essentially extend[] the current contracts for an additional 10 years, i.e., from 2015 to 2025." | N/A |
| **PU-15-96**<br>**Advance Prudence – 345 MW Mankato Energy Center**<br>ORDER<br>(03/23/16)<br>Order Pt. 2 | ADP application for the Calpine PPA dismissed without prejudice. | N/A |
| **PU-17-270, 271 & 322**<br>**Advance Prudence – Biomass PPA Applications**<br>ORDER<br>(06/27/18)<br>Sec. II.A pg. 3. | ADPs granted for the Pine Bend and Laurentian Transactions with no conditions, and ADP granted for the Benson Transaction is granted for all anticipated costs of the Benson Transaction but for the costs to reimburse the City of Benson for certain stranded water, wastewater, and electric distribution assets as described by the Company and identified by Mr. Heidell. | N/A |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-17-120 & PU-17-372**<br>**Advance Prudence – 1,550 MW Wind Portfolio & 302.4 MW Dakota Range Wind**<br>ORDER ON SETTLEMENT (12/06/18)<br>Terms Sec. A, pp. 4-5 | The Parties therefore agree that an ADP for each of the projects comprising the Wind Portfolio and the Dakota Range I and II projects be granted subject to the following conditions:<br>1. The Foxtail, Blazing Star I, Blazing Star II, Freeborn, and Dakota Range I and II Projects (collectively, the Self Build Projects) are prudent up to the amount identified in Table 1, Line 5 of the Joint Stipulation of Capital Expenditure Costs filed in the above referenced Cases (Joint Stipulation) (Self Build Expenditure Amount) as may be adjusted due to the cancellation of a particular Self Build Project through subtraction of the budgeted capital expenditure cost of the cancelled project as identified in the Joint Stipulation from the Self Build Expenditure Amount. The foregoing finding of prudence up to the Self Build Expenditure Amount, does not imply that any costs above the Self Build Expenditure Amount are imprudent.<br><br>2. The Lake Benton and non-PPA portion of the Crowned Ridge Projects (collectively, the BOT Projects) are prudent up to the amount identified In Table 2, line 3 of the Joint Stipulation ("BOT Expenditure Amount" and, collectively with the Self Build Expenditure Amount the "Expenditure Amounts"), as may be adjusted due to the cancellation of a particular BOT Project through subtraction of the budgeted cost of the cancelled project as identified in the Joint Stipulation from the BOT Expenditure Amount. The foregoing finding of prudence up to the BOT Expenditure Amount does not imply that any costs above the BOT Expenditure Amount are imprudent.<br><br>3. The Clean Energy #1 and non-BOT portion of the Crowned Ridge Project (collectively, the PPA Projects) are prudent under their contract terms without condition. | N/A |

| OTHER COMPLIANCE ITEMS | | |
|---|---|---|
| **Case No.** | **Required Information** | **Section and Page of Application** |
| **PU-18-430**<br>**Advance Prudence – 151.2 MW Dakota Range III**<br>ORDER<br>(12/03/19) | NSP's application for an advanced determination of prudence for its power purchase agreement with Dakota Range III, LLP is GRANTED with the following conditions:<br>a. North Dakota customers shall receive financial compensation for their share of RECs associated with the project in the same manner and form as North Dakota customers receive financial compensation for their share of RECs for other NSP projects; and<br>b. North Dakota customers be held harmless and not pay for any costs associated with procuring RECs that NSP may have to purchase to satisfy its commitments under the Google ESA. | N/A |