Exhibit 6

Direct Testimony and Schedule
Kelly A. Bloch

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___(KAB-1)

Distribution

November 6, 2020

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Schedule

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Kelly A. Bloch. I am the Regional Vice President, Distribution Operations for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (the Company or NSPM) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 29 years of experience in the utility industry. I joined Public Service Company of Colorado, another operating company of Xcel Energy, in 1991 and have served in various engineering roles since that time. In my current role, I am responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of North Dakota, Minnesota, South Dakota, Michigan, and Wisconsin. My Statement of Qualification is attached as Exhibit___(KAB-1), Schedule 1.

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

A. My testimony supports the prudence of the revenue requirement increases attributable to the Distribution function driving the need for this rate case as described by Company witness Mr. Greg Chamberlain. The Company has made significant capital additions that have been placed in service since 2013 or are currently forecasted to be placed in service by the Distribution function in 2021, and there are also increased operations and maintenance costs for Distribution.

I begin my testimony by discussing the Distribution function's capital expenditures, including key programs and projects, and how those support Xcel Energy's provision of safe and reliable service at reasonable costs.

I then present Distribution's historic and forecasted operations and maintenance (O&M) expenditures and how they support Distribution's key mission of supporting system reliability.

Finally, I discuss the Company's Advanced Grid Intelligence and Security (AGIS) initiative. AGIS is a transformative portfolio of grid modernization investments that will create the distribution grid of the future, enhancing reliability, shortening the duration of power outages, integrating intermittent resources, and empowering customers with more information to control and track their energy use. I also support the Company's current and test year capital investments in AGIS as well as the related test year O&M expenses related to AGIS.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The Distribution organization is responsible for operating, maintaining, and constructing the distribution system that is the critical final link in delivering electricity to our customers to power their homes and businesses. Much of Distribution's investments and efforts are focused on maintaining the reliability, resiliency, and health of our existing distribution facilities. In order to maintain these facilities, we regularly evaluate the health of the key components of our distribution system and make the necessary investments to ensure these facilities are safe and reliable. This includes an evaluation of the condition, age, and performance of the key components of our system

such as poles, underground cables, and substation transformers. We also must make significant investments to support system capacity needs due to increased loads, update existing infrastructure, and carry out projects in response to public works projects.

Between 2013 and 2017, our Distribution capital investments were relatively consistent on an annual basis, in 2018 and 2019 there was a notable increase, and now there are forecasted decreases for 2020 and the 2021 test year. The increased capital spending in 2018 and 2019 resulted from the prioritization of the Company's replacement programs for poles, underground residential distribution cable, and 500 MCM unjacketed cable, and from significant upgrades to substation transformers and feeders which I describe further below. The Company's investments have resulted in significantly improved reliability from 2013 to 2019, and I conclude the capital portion of my Direct Testimony by presenting the data showing those improvements.

Next, I turn to Distribution's O&M expenditures on the maintenance of existing assets, the programmatic annual inspections of poles and replacement of poles as necessary, vegetation management, and damage prevention through locating underground electrical facilities. As a result of strong management practices, we have been able to keep our O&M costs relatively flat between 2013 and 2019. However, we are forecasting increased O&M costs for 2021, and I describe the factors resulting in that increase: higher labor costs, increased vegetation management costs, a rise in damage prevention costs, and costs attributable to AGIS.

AGIS is the Company's multi-year project to create benefits for customers by transforming our distribution system into an intelligent and highly automated system. In this long-term strategic initiative, we are modernizing and transforming our electrical distribution grid to enhance reliability, efficiency, and security, to ensure the safe operation of the grid with the bi-directional flow of energy, and to enable and support improved customer products and services into the future. The Company's current meters need to be replaced, which, along with the maturation of other relevant technologies, makes this the right time to implement AGIS.

Below, I describe the individual components of AGIS in detail. Each of the components will benefit customers and improve the functioning of the grid. In broad terms, AGIS will give the Company more of a real-time ability to understand and control the functioning of the system. Currently, we have only limited information as to what happens beyond the substation level. Somewhat similarly, customers currently have only limited insight into their own energy usage. AGIS empowers both customers and the Company by providing better and more current information. Implementation of AGIS will require both capital investment and O&M spending, and I present specific figures below, including forecasted spending beyond the 2021 test year.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section I* – Introduction
- *Section II* – Distribution Functions
- *Section III* – Distribution Capital Investments
- *Section IV* – Distribution Operations and Maintenance Expenditures

- *Section V* – AGIS Initiative
- *Section VI* – Conclusion

II. DISTRIBUTION FUNCTIONS

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S DISTRIBUTION SYSTEM.

A. The Company's distribution system serves approximately 95,000 electric customers across North Dakota. The distribution system is the final link that provides electricity to our customers' homes and businesses, safely and reliably. The Company's distribution system in North Dakota includes eleven (11) distribution substations and sixty-five (65) feeders.

Q. WHERE ARE THOSE DISTRIBUTION SUBSTATIONS LOCATED?

A. The Company has two in each of Fargo and Grand Forks and one in each of Minot, Larimore, Mayville, Hatton, Thompson, Reynolds, and Cummings.

Q. WHAT ARE THE RESPONSIBILITIES OF THE DISTRIBUTION BUSINESS UNIT?

A. The Distribution organization is one of the Company's business units whose investments and work directly impact the daily lives of our customers. The key functions of the Distribution organization include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to enhance the performance and reliability of the distribution system.

The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. Our work

includes new construction to extend service to new customers or increasing the capacity of the system to accommodate new or increased load, repairing facilities damaged during severe weather to restore service to customers quickly, and performing regular maintenance and repairs on poles, wires, underground cables, metering, and transformers.

Our organization is also responsible for the primary implementation and support for the Company's AGIS initiative, which is intended to enhance reliability, increase security, improve efficiency, and support our ability to provide customers with additional products and services into the future. I discuss the AGIS initiative further in Section V of my Direct Testimony.

Q. PLEASE DESCRIBE THE STRUCTURE OF THE DISTRIBUTION BUSINESS UNIT.

A. To serve North Dakota customers, Distribution divides its work into five functional areas:

- *Distribution Operations.* Responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response;
- *Engineering.* Responsible for technical support and system planning, including addressing distribution-related customer service issues;
- *Business Operations.* Responsible for several areas, including vegetation management, outdoor lighting, facility attachments, and the builders call-line;
- *Planning and Performance.* Responsible for business planning, consulting, analytical services and performance governance and management; and

- *AGIS and Metering.* Responsible for implementing the AGIS initiative and metering.

Q. HOW MANY EMPLOYEES WORK IN THE DISTRIBUTION BUSINESS UNIT?

A. Across the Northern States Power Minnesota operating company (which encompasses our North Dakota operations), there are 929 full-time employees performing the functions of the Distribution business unit. Just over half of those employees (527 full-time employees) are in bargaining units. Additionally, employees of XES provide support to all Xcel Energy operating companies. The budget of each operating company – including that of NSPM – assumes support by a certain number of employees of the Service Company based on the number of line miles in the service territory. NSPM assumes support of 175 full-time Service Company employees. Finally, certain employees of the Gas Engineering and Operations business area support the electric utility's work.

III. DISTRIBUTION CAPITAL INVESTMENTS

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

A. In this section of my Direct Testimony, I describe the capital investments the Distribution business unit makes to deliver safe, reliable electric service to our North Dakota customers.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. First, I provide a broad overview of the types of capital investments the Distribution business unit makes and the process for planning and implementing those investments. Next, I discuss Distribution business unit

capital investments made since 2013, which the Company is proposing to add to the rate base, and which are a driver for the broader rate case. Last, I set forth Distribution's forecast for non-AGIS capital additions in the 2020 current year and the 2021 test year (I present our forecasts of capital additions related to AGIS in Section V).

A. Types of Distribution Capital Investments

Q. TO PROVIDE RELIABLE, SAFE ELECTRIC SERVICE FOR NORTH DAKOTA CUSTOMERS, DOES DISTRIBUTION MAKE CAPITAL INVESTMENTS?

A. Yes, the Distribution business unit makes capital investments to maintain, and where possible enhance, the reliability and functionality of the distribution system, extend service to new customers, and relocate facilities in response to road construction or other governmental projects. Also, in partnership with other areas of the Company, Distribution makes capital investments in support of the AGIS initiative.

Q. WHAT TYPES OF CAPITAL INVESTMENTS DOES THE DISTRIBUTION FUNCTION MAKE IN ORDER TO PROVIDE RELIABLE, SAFE ELECTRIC SERVICE FOR NORTH DAKOTA CUSTOMERS?

A. The majority of our investments are made to maintain the health and reliability of our facilities through replacement of aging or damaged equipment. By making these investments, we maintain and enhance reliability of service for customers. As I discuss further below, since our last North Dakota rate case we made investments in poles, feeder lines, substation transformers, and replacement of underground cables—all to maintain the health of these key components of our system and thereby provide reliable service for our North Dakota customers. Where necessary, we also make necessary improvements

to provide increased capacity. These capacity investments increase the ability of the distribution system to handle system load growth and to serve load when other elements of the distribution system are out of service. Projects in this category include installing new or upgraded substation transformers and distribution feeders.

The Company also makes capital additions to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public works projects such as a road widening or realignment project. Such mandate projects typically result in updated distribution infrastructure that benefits the system and customers. The Company also invests in the tools, equipment, and fleet that its personnel need to perform their jobs.

Additionally, since 2017, Xcel Energy has made strategic investments in the Company's AGIS initiative to advance distribution grid capabilities, increase our visibility into the system and control of it, and to enable expanded customer options, which is discussed in Section V below.

Q. PLEASE SUMMARIZE THE PROCESS THE COMPANY USES TO DETERMINE WHAT INVESTMENTS TO MAKE.

A. On an ongoing basis, the Company identifies necessary routine and non-routine investments into the distribution system. The Company divides expenditures into routine and non-routine categories depending upon whether we expect the expenditure to re-occur. Regarding routine projects, Distribution makes those capital additions necessary as a regular, common part of maintaining a properly functioning distribution system. For non-routine projects, Distribution identifies risks to the distribution system and

possible capital additions to mitigate those risks and scores the possible projects to determine a priority order. The Company uses that priority order to guide its investments as the amount of capital varies from year to year. At the same time, the Company remains flexible so that if an emergency occurs during a given year, such as a storm or flood, the Company can adjust the priority of projects on the approved list. In summary, we meet identified needs and requirements, adjust to changing circumstances, and prudently promote the long-term health of the distribution system.

Q. HOW ARE DISTRIBUTION'S CAPITAL ADDITIONS ALLOCATED TO THE NORTH DAKOTA JURISDICTION?

A. As the last mile of service, Distribution's activities accrue benefits that are more localized in nature than other Company functions such as Energy Supply, Transmission, and Business Systems (Information Technology) which support the entire NSP System. Consequently, Distribution's capital and O&M tend to be differently allocated than system-wide resources.

Distribution's capital additions are, in general, directly assigned to the North Dakota jurisdiction – just like Distribution's capital additions in South Dakota and Minnesota are directly assigned to those jurisdictions. For example, all of the costs of a Distribution capital addition of a new substation in Grand Forks would be direct assigned to the North Dakota jurisdiction. This is mainly because the distribution capital additions support local electric service in the particular jurisdiction.

As the Company's distribution system advances through the implementation of AGIS, we also expect to utilize allocators for certain AGIS costs rather than

merely directly assigning them. We expect to take this approach because many elements of the AGIS initiative are more akin to networks that provide broad-based support for the distribution system, rather than being local in nature. Company-wide deployment of these technologies and software to support them are, therefore, treated more like information technology investments rather than local investments in distribution.

Q. PLEASE DESCRIBE HOW DISTRIBUTION'S CAPITAL INVESTMENTS BENEFIT NORTH DAKOTA CUSTOMERS.

A. Distribution's capital investments support various initiatives, activities, and responsibilities. For example, these investments keep assets working properly, provide customers with reliable service, serve new load, support new capacity, accommodate public works projects, and provide employees with the tools and equipment they need to perform their job responsibilities.

Q. HOW DO CAPITAL INVESTMENTS KEEP ASSETS WORKING PROPERLY AND PROVIDE CUSTOMERS WITH RELIABLE SERVICE?

A. Distribution invests capital to replace infrastructure that may experience failure and, as a result, negatively impact service reliability and increase O&M expenditures needed to repair the equipment. Projects in this category include replacement of underground cable, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their life. This category also captures replacements due to storms and public damage. Distribution designates capital additions in this category as Asset Health and Reliability projects.

Q. HOW DO CAPITAL INVESTMENTS SERVE NEW LOAD?

A. Distribution invests capital to build new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, and service laterals that bring electrical service from an existing distribution line to a new home or business.

Q. HOW DO CAPITAL INVESTMENTS SUPPORT NEW CAPACITY?

A. Distribution's investments in support of capacity increase the ability of the distribution system to handle system load growth and to serve load when other elements of the distribution system are out of service. Projects in this category include installing new or upgraded substation transformers and distribution feeders.

Q. HOW DO CAPITAL ADDITIONS ACCOMMODATE PUBLIC WORKS PROJECTS?

A. When a unit of government widens a road, for example, the Company makes a capital investment to relocate utility infrastructure in public rights-of-way. These mandate projects typically result in updated distribution infrastructure.

Q. HOW DO CAPITAL ADDITIONS PROVIDE EMPLOYEES WITH THE TOOLS AND EQUIPMENT THEY NEED TO PERFORM THEIR JOB RESPONSIBILITIES?

A. Distribution makes capital investments in tools, equipment, communication equipment, and costs to locate existing utility lines. Distribution also invests in replacing fleet vehicles that have reached the end of their useful lives.

B. Overview of Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NON-AGIS DISTRIBUTION PLANT ADDITIONS FROM 2013 TO 2021.

A. The Table below reflects Distribution capital additions placed in service from 2013 through the 2021 forecast, broken down by category.

Table 1

Distribution Non-AGIS Capital Additions 2013-2021

State of ND Electric Jurisdiction Plant Additions (includes AFUDC)	2013	2014	2015	2016	2017	2018	2019	2020	2021
Asset Health & Reliability	$5.3	$3.3	$2.7	$4.0	$4.0	$4.4	$4.7	$5.5	$3.2
Capacity	$3.3	$4.3	$2.4	$1.7	$0.6	$2.2	$6.3	$2.9	$0.1
New Business	$2.2	$2.5	$3.6	$2.4	$2.3	$3.4	$2.2	$0.9	$2.2
Fleet, Tools & Comm	$0.2	$0.2	$0.4	$0.3	$0.5	$0.6	$0.3	$0.5	$0.8
Mandates	$0.3	$1.2	$0.2	($0.0)	$0.2	$0.8	$0.2	$0.5	$0.3
Solar Program	$0.0	$0.0	$0.0	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)
Total	**$11.3**	**$11.5**	**$9.3**	**$8.4**	**$7.7**	**$11.3**	**$13.8**	**$10.4**	**$6.6**

Q. WHAT TRENDS DOES THIS TABLE ILLUSTRATE IN THE COMPANY'S NON-AGIS DISTRIBUTION CAPITAL ADDITIONS FROM 2013-2021?

A. The table illustrates we made investments in refreshing the system during the term of the Settlement from our last rate case, then had a relatively consistent level of capital investment through 2017, a notable increase in 2018-2019, a forecasted decrease in 2020, and another forecasted decrease in 2021.

Q. WHAT DROVE THAT INCREASE IN CAPITAL ADDITIONS IN 2018-2019?

A. As I detail later in my testimony, in 2018 and 2019 the Company prioritized replacement programs for poles, underground residential distribution cable, and 500 MCM unjacketed cable, and undertook significant upgrades to substation transformers and feeders to enhance system reliability. These investments in the distribution system led to increased capital additions compared to previous years.

Q. WHY DO THE COMPANY FORECASTED CAPITAL ADDITIONS FOR 2021 DECREASE COMPARED TO 2020?

A. By 2021, the Company will complete our current cycle of prioritized investments in the distribution system. As a result, we forecast that we will be able to continue providing reliable service to North Dakota customers with a lower level of capital investment than in preceding years.

Q. GIVEN THE REDUCTION IN CAPITAL ADDITIONS FOR THE 2021 TEST YEAR, WHY IS THERE STILL A $1 MILLION IMPACT TO THE REVENUE REQUIREMENT?

A. As Company witness Benj Halama discusses in his testimony, the $1 million revenue requirement driver includes the impact on rates of capital investments the Company made in previous years. In broad terms, several years have passed since the 2013 test year used in the last rate case and there have been significant capital investments made since then. More specifically, the rate impact of our increased investments in 2017-2019 are fully being realized during the 2021 test year.

1. Investments Across the Distribution System in North Dakota

Q. SINCE THE LAST RATE CASE, DID THE COMPANY MAKE ANY CAPITAL INVESTMENTS BROADLY ACROSS THE DISTRIBUTION SYSTEM IN NORTH DAKOTA?

A. Yes. The Company made a variety of investments to enhance the reliability and performance of the distribution grid throughout our North Dakota service territory. My Direct Testimony will focus mainly on the recent investments we made in 2018-2020 since, as shown above, these investments were over and above our usual capital additions to the Distribution System.

Q. PLEASE SUMMARIZE THOSE INVESTMENTS.

A. The Company invested in pole replacement, new cable, and IntelliTeam switches. In addition, throughout our North Dakota service territory the Company deployed a VAR management system, replaced the Frame Relay communications network, and deployed light emitting diode (LED) streetlights. I describe each of these key investments in more detail below.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENT IN POLE REPLACEMENT.

A. The Company invests in rebuilding, replacement, and renewal of poles to enable them to withstand weather events, continue to provide a sturdy underpinning for the distribution grid, and prevent safety hazards for customers or Company employees. The NSPM distribution system has approximately one half million wooden poles in service with 23,000 in North Dakota. These poles have a service life, on average, of 40 to 50 years, and those poles at the end of their service life have the highest rate of failure. Pole rot at the base of the pole can be a cause of pole failure, especially during storms.

To identify poles in need of replacement, the Company employs a 12-year inspection cycle. The Company seeks to replace poles identified for replacement within one year of the inspection. The number of poles inspected each year can vary depending on overall budget management efforts and the number of poles replaced each year depends on the rejection rate of the inspected poles. Due to the overall age of the poles on our system, as well as fine tuning of the inspection process and criteria, the number of poles that are identified for replacement has increased steadily since 2012. For instance, in 2019 and 2018 the rejection rate, the proportion of poles that fail testing and need to be replaced or reinforced to ensure the physical integrity of the pole, was approximately 13 percent per year whereas the average historical rejection rate for poles inspected has been approximately 9 percent. While the rejection rate for poles can fluctuate each year based on the age and condition of the particular poles inspected in that year, this recent increase in the rejection rate underscores the need to place greater focus on these key assets.

Capital additions for pole replacement totaled $1.595M from 2013 to 2019.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS TO ENHANCE RELIABILITY OF CABLE THROUGHOUT THE DISTRIBUTION SYSTEM.

A. Historically, North Dakota customers have experienced reliability issues due to failing 500 MCM unjacketed cable. This is an issue experienced throughout the electric utility industry. The technology and manufacturing of cable has improved over the years and a jacket around the concentric neutrals provides much better protection from soil and environmental corrosion extending the useful life of the cable. In response to that advancement, the Company has

taken a proactive approach to improving reliability by replacing unjacketed cable with jacketed cable. Over the last five – seven years, North Dakota areas have proactively replaced approximately 95 percent of the old unjacketed cable. Similarly, the Company has prioritized the replacement of underground residential distribution cable that was originally installed in the 1970s and has been failing in recent years. Additionally, the Company has invested in underground extensions, conversions, reinforcements, and rebuilds. These investments in undergrounding created benefits for our customers of increased reliability—since wires underground are less impacted by storms and animals than overhead wires—and improved aesthetics. The Company has invested in this initiative consistently, making capital additions totaling $4.580M from 2013 to 2019.

Q. PLEASE DESCRIBE THE VAR NETWORK SYSTEM PROJECT.

A. To deliver high-quality, reliable power to customers, the Company measures and controls reactive power. The measurement of reactive power is "voltage-ampere reactive," abbreviated as "VAR." To better control reactive power, the Company deployed new controls in and around Minot, Grand Forks, and Fargo to automate the control of these capacitor banks for VAR support. Specifically, the Company invested in new capacitor bank controls that communicated via a cellular modem along with a newly deployed VAR management system. The Company installed approximately 30 of these upgraded controllers in each of Minot, Grand Forks, and Fargo. By providing the remote capabilities of the cellular controls, we can better manage voltage along the feeder improving power quality to our customers. Power quality is important to help protect sensitive equipment – such as variable frequency drivers for motors and power sensitive electronics – that could be tripped

offline or damaged necessitating replacement. By having better remote capabilities to control our capacitor banks and manage VAR support, we can better support customers' power needs. This also allows us to operate the distribution system more efficiently lowering overall costs. We began these capital additions in 2014 and continued through 2018, for a total capital addition of $0.233M.

Q. PLEASE DESCRIBE THE COMPANY'S REPLACEMENT OF THE FRAME RELAY COMMUNICATIONS NETWORK.

A. Frame relay is a communication service that we built our private communications network around that allows our substations to communicate with our control centers. Historically, the Company had used a particular frame relay communications network throughout its distribution and transmission system, including in North Dakota. The vendors providing the frame relay service have stopped supporting it, and the Company was required to make alternative arrangements to maintain essential connectivity through the network thus ensuring the continued flow of essential operational data to our control centers. Without these communications networks we would not be able to efficiently manage the distribution system because there would be no connectivity between our substations and our control centers. Accordingly, beginning in 2016 the Company began investing in replacement of the frame relay communications network throughout the Company's distribution system, including in North Dakota. These capital additions totaled $0.274M from 2016 to 2019.

Q. PLEASE DESCRIBE THE COMPANY'S DEPLOYMENT OF LED STREETLIGHTS ACROSS ITS NORTH DAKOTA SERVICE TERRITORY.

A. In 2016, we deployed LED streetlights in Fargo, Grand Forks, and Minot—plus Berthold, Burlington, Buxton, Cummings, Des Lacs, Hatton, Larimore, Mayville, Portland, Reynolds, Riverside, Thompson, and West Fargo. These LED streetlights create a variety of benefits for customers: compared to incandescent streetlights, LED streetlights are more energy-efficient, last longer, and put less strain on the grid. In addition, the switch to LED lighting promotes safety by improving nighttime visibility for both drivers and pedestrians. The Company made a total of $1.367M in capital additions on LED streetlights. The Commission approved our LED Street Lighting Program in Case No. PU-15-692.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENT IN INTELLITEAM SWITCHES.

A. In 2012, the Commission approved the Company's proposals to take specific steps to enhance reliability, including the installation of IntelliTeam switches and hiring of an engineer to be located in Fargo. Case No. PU-10-657, Order on Settlement, February 29, 2012. Over a three-year period, the Company installed 48 IntelliTeam switches and ancillary communications equipment to deliver this benefit. The IntelliTeam switches enhance reliability by providing the Company with remote visibility and control of certain switchgear on the distribution grid. The capital addition for IntelliTeam since 2013 totaled $1.1M. The addition of these switches has contributed to the improved the overall reliability in North Dakota as discussed further in Section V.B below.

2. Distribution Investments in Specific Portions of the Company's North Dakota Service Territory

Q. HAS THE COMPANY MADE KEY CAPITAL INVESTMENTS IN PARTICULAR PORTIONS OF ITS NORTH DAKOTA SERVICE TERRITORY SINCE 2013?

A. Yes, as the Commission is aware, the Company provides service in the Fargo, Grand Forks, and Minot areas. Each of those geographic locations has its own distribution system, unconnected to the others, requiring ongoing analysis of each area. The Company continuously evaluates opportunities to make the distribution system more robust in each area.

Since our last rate case, we implemented action plans to enhance reliability of service in and around Grand Forks, Fargo, and Minot. As detailed below, we installed new transformers and feeders at substations in those areas. These investments also increased the distribution system's capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service.

a. Key investments in Grand Forks

Q. YOU STATED THAT THE COMPANY CONTINUOUSLY EVALUATES OPPORTUNITIES TO MAKE THE DISTRIBUTION SYSTEM MORE ROBUST. DID THE COMPANY IDENTIFY ANY SUCH OPPORTUNITIES IN THE GRAND FORKS AREA?

A. Yes. To help ensure that customers in Grand Forks would continue to receive service even if a portion of the distribution system experienced a temporary disruption, the Company invested in upgrades to the two substations serving Grand Forks.

Q. PLEASE BRIEFLY DESCRIBE THOSE SUBSTATIONS.

A. Two substations serve the Grand Forks area: Nordic, which serves the south and west portions of the city, and Gateway, which serves the north and east portions of the city.

Q. PLEASE DESCRIBE THE UPGRADES TO THE NORDIC SUBSTATION.

A. From 2014 through 2020, the Company installed an additional 50 MVA transformer at Nordic substation—to make a total of three transformers at that substation—and feeder lines running to that substation. With the addition of the transformer and feeder lines, the Company created redundancy to support reliability and increased its capacity to support load growth in Grand Forks. The redundant equipment enhances reliability because in the event that one feeder line or transformer is out of service due to equipment malfunction, regular maintenance, or weather event, the additional components the Company has installed would continue to provide service, reducing the risk of customers experiencing an outage. From 2014-2020 we made capital additions at the Nordic substation of $8.7 million.

Q. PLEASE DESCRIBE THE UPGRADES TO THE GATEWAY SUBSTATION.

A. There are six underground feeder cables that exit the Gateway substation. The Company upgraded all of those underground feeder cables to increase the load carrying capability of the feeders. This upgrade created benefits to the distribution system and customers by providing additional capacity on local feeders and improving reliability with the installation of newer cable. The Company made this investment in 2015 for a capital addition of $0.720M.

b. Key investments between Grand Forks and Fargo

Q. PLEASE DESCRIBE THE COMPANY'S ACTIONS TO ENHANCE RELIABILITY IN THE AREA BETWEEN GRAND FORKS AND FARGO.

A. In 2018, the Company had an opportunity to achieve multiple goals simultaneously for the benefit of individual customers and the broader distribution system. At the South substation in Cummins—between Fargo

and Grand Forks—there was a transformer that served the local community. The Company identified three issues it could address through capital investment. First, that transformer was aging and in need of replacement. Second, the Company's distribution system in the area was a 4.16 kV system, a relatively lower voltage than in other areas on the Company's distribution system. The Company continues to operate the lower-voltage system effectively while looking for appropriate opportunities to upgrade to higher voltage. And third, a local farmer was upgrading a grain elevator, requiring additional investment in the area to support the new load.

To address these issues simultaneously, the Company invested in replacing the aging transformer and upgrading the distribution system in the area to a more robust 12.5 kV. The investment improves reliability of the transmission and distribution systems in that area and allows for future growth. As an added benefit, the Company will save money by not having to maintain spare components for the lower-voltage system. The capital addition associated with these improvements through 2020 is $0.918M.

c. Key investments in Fargo

Q. DID THE COMPANY IDENTIFY ANY OPPORTUNITIES FOR ENHANCEMENTS IN THE FARGO AREA?

A. Yes. To help ensure that customers in Fargo would continue to receive service even if a portion of the distribution system experienced a temporary disruption, the Company invested in upgrades to the substations serving Fargo and to feeder lines serving those substations.

Q. WHAT SUBSTATIONS SERVE FARGO?

A. Two substations serve Fargo: the Cass County and Red River substations.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN THE CASS COUNTY SUBSTATION.

A. In 2013, we installed a third 50 MVA transformer at the Cass County substation in Fargo for a capital addition of $3.0M. This third transformer provides redundancy, so that if one of the transformers at the substation stops functioning properly or requires maintenance, the others will ensure reliable service for customers.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN THE RED RIVER SUBSTATION AND ASSOCIATED FEEDERS.

A. In 2013, the Company purchased a spare transformer for the Red River Substation, a capital addition of $3.0M. In 2015-2020, we built new feeders connected to that substation to increase redundancy in and around the Red River Substation for capital additions of $0.9M.

Q. PLEASE DESCRIBE THE BENEFITS OF THESE INVESTMENTS.

A. In the event that a transformer fails, having a spare transformer on hand enables the Company to respond restore service more quickly than if we had to obtain a transformer from a distant location. Additionally, the redundant feeders and transformer at the Red River substation enhance reliability. Specifically, in the event that one feeder line or transformer is out of service due to equipment malfunction, required maintenance or weather event, the additional components the Company has installed would continue to provide service, reducing the risk of customers experiencing an outage.

Q. PLEASE DESCRIBE HOW THE UPGRADES TIE THE DISTRIBUTION SYSTEM INTO A NEW TRANSMISSION LINE.

A. In 2018 and 2019, the Company constructed a five-mile, 115 kV transmission line within the City of Fargo and Reed Township. In 2017, the Commission granted a Certificate of Public Convenience and Necessity for the project, named the Maple River-Red River 115 kV Transmission Line Project. Case No. PU-17-332, Order, November 29, 2017. The line is a second circuit connecting the Company's Maple River and Red River substations. The project provides increased reliability in the Fargo area by reducing overloads on neighboring lines and transformers. To make way for that project, the Company had to relocate one of the Red River feeders and a tap. Once the Company completed the project, the feeders were underbuilt on the newly constructed transmission lines. This resulted in a total capital addition of $343,000. The result was that the feeder lines are now installed on more durable infrastructure.

d. Key investments in Minot

Q. PLEASE DESCRIBE THE COMPANY'S ACTIONS TO ENHANCE RELIABILITY OF THE DISTRIBUTION SYSTEM IN MINOT.

A. To enhance reliability in Minot, the Company made capital investments in the substation serving Minot and in support of broader Minot flood protection efforts.

Q. PLEASE DESCRIBE THE CAPITAL INVESTMENTS IN THE SUBSTATION SERVING MINOT.

A. Minot is served by one distribution substation: the Souris substation. To provide reliable service for customers in Minot, the Company made a number of capital additions at that substation from 2014 through 2018. Specifically, the Company replaced a smaller (28 MVA) transformer with a 50 MVA transformer, built new feeders, built a new feeder bay, and installed circuit switchers. The reinforced transformer creates benefits for customers and the grid by providing redundancy should a transformer trip off-line and providing additional capacity to support then heavily loaded feeders in the area. The new feeders create redundancy of components, thereby helping to ensure reliability—since if one feeder line is out of service, the others can continue providing service to Minot residents. Installation of the circuit switchers prevents a high-side fault on the transmission line from disrupting the distribution grid. All these investments reduce the risk of a loss of service within Minot and enable future load growth. These capital additions total $5.251M.

Q. PLEASE DESCRIBE THE COMPANY'S ACTIONS IN SUPPORT OF MINOT FLOOD PROTECTION.

A. The Souris River Joint Board (Joint Board) has been undertaking an extensive flood prevention effort in Minot. As part of that initiative, the Joint Board designated a path for a flood-protection wall in Minot. The path of the flood-protection wall is along the same route as a feeder line running out of the Souris substation. Accordingly, the Company had to relocate distribution infrastructure to accommodate the forthcoming flood-protection wall. In 2018, the Company relocated overhead facilities and converted overhead facilities to be underground, for capital additions of $1M. We continue to

work with the Joint Board regarding future work arising from flood protection improvements.

These flood protection related expenditures are a good example of investments due to mandates. This category covers projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public works projects such as a road widening or realignment project. Mandate projects typically result in updated distribution infrastructure.

C. Reliability Results

Q. YOU HAVE DESCRIBED PARTICULAR INVESTMENTS IN THE DISTRIBUTION SYSTEMS IN FARGO, GRAND FORKS, AND MINOT AND GENERALIZED INVESTMENTS THROUGHOUT THE DISTRIBUTION SYSTEM. HAVE THE COMPANY'S DISTRIBUTION INVESTMENTS PROVIDED RELIABILITY BENEFITS FOR CUSTOMERS?

A. Yes. As detailed below, the Company's investments in the distribution system have increased the reliability of service to customers.

Q. HOW DOES THE COMPANY TRACK DISTRIBUTION SYSTEM RELIABILITY?

A. The most common industry metrics for tracking reliability performance are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI), which are tracked both on all days and on a normalized basis to exclude major storm events.

Q. WHAT IS THE TREND OF THE COMPANY'S SAIDI AND SAIFI METRICS?

A. The Company's SAIDI and SAIFI performance has varied over time, but the most recent year measured is the best it has been since the Company's last rate case in 2013. The Company continues to be a leader in terms of reliability performance. The Company's performance in North Dakota is consistently in the top performance quartile and, on average, customers have electric service more than 99.9 percent of the time. The following chart provides details:

Table 2

State of North Dakota System Level Indices – IEEE State Normalized

	2013 YE	2014 YE	2015 YE	2016 YE	2017 YE	2018 YE	2019 YE
SAIDI	74.3	57.1	69.7	83.0	43.7	52.4	42.2
SAIFI	0.83	0.65	0.72	0.91	0.59	0.49	0.38

Q. WHAT DOES TABLE 2 TELL YOU ABOUT THE COMPANY'S RELIABILITY PERFORMANCE??

A. Table 2 demonstrates that from 2013 to 2019 the Company has materially enhanced the reliability of the distribution system. While there can be reliability challenges in individual years (such as more or less extreme weather), the long-term trend indicates that the Company's continued investment in the distribution system is reaping reliability benefits. Comparing 2013 to 2019 identifies a nearly fifty percent improvement in both SAIDI and SAIFI metrics which demonstrates that, over time, the Company's investments are improving service for customers.

IV. DISTRIBUTION OPERATIONS AND MAINTENANCE EXPENDITURES

Q. WHAT DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. First, I provide a broad overview of the types of Distribution operations and maintenance (O&M) expenses and the process for planning and implementing that work. Next, I present Distribution's 2013-2021 O&M expenditures, including key drivers and trends.

A. Nature of and Process for Distribution O&M Expenses

Q. FOR WHAT TYPES OF ACTIVITIES DOES DISTRIBUTION INCUR O&M EXPENSES?

A. Distribution's O&M expenditures fall into four categories. First, Distribution makes O&M expenditures on existing pole and wire assets, including equipment maintenance, underground cable fault repair, storm repair, and inspections. Second, Distribution makes programmatic annual inspections of poles and replacement of poles as necessary. Third, the Company manages vegetation to maintain proper line clearances and distribution pole right-of-way and address vegetation-caused outages. Fourth, the Company prevents damage by locating underground electric facilities.

Q. PLEASE DESCRIBE THE COMPANY'S WORK TO MANAGE VEGETATION.

A. The Company and its contractors prune, remove, mow, and apply herbicide to trees and tall-growing brush on and adjacent to the Company's rights-of-way to limit preventable vegetation-related interruptions.

Q. WHY IS IT IMPORTANT FOR THE COMPANY TO HAVE AN EFFECTIVE VEGETATION MANAGEMENT PROGRAM?

A. An effective Vegetation Management program is essential for providing reliable service to our customers. Tree-related incidents are among the top two causes for electrical outages on our NSPM distribution system and well as the North Dakota jurisdiction. Meeting our vegetation management goals will minimize tree-related interruptions and promote public and employee safety.

Q. PLEASE DESCRIBE THE COMPANY'S DAMAGE PREVENTION PROGRAM.

A. The Company makes expenditures to locate underground electric facilities and mark those locations. These efforts help excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. The budget for Damage Prevention is based on several factors: 1) internal labor costs based on approved headcount and labor rates from the collective bargaining process, 2) miscellaneous costs (materials, fleet, other) based on historical actuals, and 3) contract pricing of our Damage Prevention service providers multiplied by the forecasted number of tickets.

Q. DOES THE COMPANY USE CONTRACTORS FOR ITS VEGETATION MANAGEMENT AND DAMAGE PREVENTION PROGRAMS?

A. Yes, the Company utilizes contractors extensively to implement our Vegetation Management and Damage Prevention programs. These programs require performance of specialized tasks (e.g., tree trimming, pole inspections, underground facility locating) by a seasonal workforce. Accordingly, the Company has determined that the use of contract labor is more cost effective and efficient than utilizing employees. With contractor labor, the Company can competitively bid out these services to obtain well-trained and established work forces specializing in these areas. In addition, by contracting these services, the Company has the flexibility to easily ramp up and ramp down the number of contractors that it needs to respond to different volumes of

workloads. This flexibility is important given the seasonal nature of this work. If the Company were to hire employees for these positions, we would have to find a way to deploy this workforce to other areas during the winter months when these tasks are not performed at the same volume as in the summer and/or as overall annual work volumes change due to the economy or other factors.

Q. HOW ARE DISTRIBUTION O&M EXPENDITURES ALLOCATED?

A. Similar to our capital additions, Distribution's O&M expenses are generally direct assigned to the North Dakota jurisdiction to the extent they are solely serving that jurisdiction. For example, vegetation management costs are direct assigned to the area where the work is completed. Accordingly, costs of vegetation management in Fargo are assigned fully to the North Dakota jurisdiction. That said, certain Distribution's O&M expenses are incurred on a Company-wide basis – for example, management costs, environmental services, planning, and certain engineering functions. These O&M expenses are allocated to the North Dakota jurisdiction using an allocation methodology.

B. O&M Expenses from 2013 to 2021

Q. WHAT DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. I present Distribution's expenditures on O&M, including key drivers and trends. Our forecasts of AGIS-related O&M expenses are discussed in Section V below.

Q. PLEASE DESCRIBE DISTRIBUTION'S HISTORIC PATTERNS OF O&M SPENDING SINCE THE COMPANY'S LAST NORTH DAKOTA RATE CASE.

A. Table 3 below shows the Company's North Dakota O&M distribution expenses for 2013 through to 2019 and the forecasted O&M expenses for 2020 and the 2021 test year.

Table 3

ND - Electric Distribution Expenses 2013 - 2021 - $M								
2013	2014	2015	2016	2017	2018	2019	2020	2021
$6.8	$ 6.7	$ 6.3	$ 6.9	$ 6.2	$ 6.7	$ 6.5	$ 6.5	$ 8.6

Q. WHAT DOES THIS TABLE SHOW?

A. Distribution has historically spent between $6.2 million and $6.9 million on O&M annually from 2013 to 2019 in support of maintaining and enhancing the reliability of the North Dakota distribution system. Due to the Company's strong management practices, we have been able to keep that amount effectively flat over that period. In 2019, North Dakota Distribution expenditures were $6.5 million.

Q. WHAT DOES THE COMPANY FORECAST FOR DISTRIBUTION O&M EXPENSE IN THE CURRENT YEAR OF 2020?

A. As shown above in Table 3, the Company forecasts North Dakota O&M expenditures of $6.5 million for the current year of 2020.

Q. WHAT DOES THE COMPANY FORECAST FOR DISTRIBUTION O&M EXPENSE IN THE TEST YEAR OF 2021?

A. As shown above in Table 3, we forecast forecasts O&M expenditures for North Dakota of $8.6 million for the 2021 test year.

Q. WHAT ACCOUNTS FOR THE INCREASE IN O&M EXPENDITURES FOR 2021 FROM THE LEVELS SEEN IN PRIOR YEARS?

A. This is one of the drivers of the rate case and that forecasted increase beyond the historic range for Distribution O&M expenses is due to multiple factors. First, $910,000 of the increase is attributable to O&M expenses associated with AGIS, which is discussed in Section V below. Next, $345,000 is an increase in the cost of Vegetation Management. Then, $403,000 is increased damage prevention costs. Finally, $310,000 is an increase in labor costs as compared to our 2019 North Dakota labor actuals and escalating by an average annual merit increase of 2.5 percent per year over two years.

Q. WHY IS THE COST OF VEGETATION MANAGEMENT INCREASING?

A. In response to the COVID-19 pandemic and the resulting drop in sales and economic uncertainty, the Company decided to reduce certain expenditures in 2020, including the budget for vegetation management. However, looking forward to 2021, we are budgeting an increase in funding of $345,000 in both 2021 and 2022 to catch-up and get vegetation management back on cycle. As noted above, maintaining the cycle of vegetation management is crucial to reducing the number of tree-related outages experienced by our North Dakota customers. In addition, we are forecasting increases in the cost of the contract workforce. As noted previously, the Company utilizes contractors extensively to perform Vegetation Management and Damage Prevention. To keep costs as low as possible, we renegotiate local contracts with vendors; however, the demand for qualified contractors has increased in recent years and we are competing with many industries for this skilled labor which impacts the costs of contract renewal.

Q. WHY ARE DAMAGE PREVENTION EXPENDITURES FORECASTED TO INCREASE?

A. The Damage Prevention program helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. The Company relies on a combination of internal labor and contractors for the Company's Damage Prevention program. We rely on contractors for much of this work to normalize for the seasonality of locate requests. Said differently, we receive many locate requests during construction season and we utilize contractors during this time, so we do not need to employ full time workers when demand is seasonal during peak times of construction season. Further, damages caused by vendors mis-locating our underground facilities is covered by the vendor, which is a contributing factor in our decision to utilize outside vendors for this type of work.

We are now forecasting increased costs for the outside contractors used to locate underground lines. We are in the process of negotiating contracts with vendors. We are currently under contract with one vendor until February 1, 2021. At the time the contract was negotiated, before the COVID-19 pandemic, the labor market for these jobs was tight. Additionally, the insurance premiums to protect the vendor from damages caused by inaccurate locates performed by their employees increased. The Company issued a request for proposal (RFP) on July 27, 2020 to obtain damage prevention services effective February 1, 2021. Vendors provided a response to our RFP on August 14, 2020. The Company is currently in negotiations with these vendors and expects negotiations to be completed and contracts awarded in November 2020. The Company is expecting an increase in the per unit price for work to be performed from 2021 to 2023 which is consistent with what the industry is seeing across the county.

Q. WHY ARE LABOR COSTS FOR NORTH DAKOTA DISTRIBUTION INCREASING?

A. The Company has managed to control labor costs over the past several years through increased efficiencies driven, in part, by our Work and Asset Management program, as well as directing our labor force to our capital investments in support of a reliable distribution system. Additionally, in 2020, we have further mitigated our labor expenses through programs instituted in light of the COVID-19 pandemic. That said, in 2021, we are forecasting an increase of $310,000 in our labor costs allocated to the North Dakota electric jurisdiction.

This increase is driven by two material factors. First, approximately $150,000 of this increase is due to the Company budgeting for labor inflation of 2.5 percent annually over a two-year period. Additionally, $160,000 of this forecasted labor increase is due to hiring two North Dakota based line workers and two North Dakota based designers. These additional positions are needed in light of a 16 percent increase from 2018-2019 in new customer connections and our forecasts of additional growth in this area. Driving this need are efforts to revitalize the Fargo area and other economic activity in areas we serve in North Dakota. In addition to supporting additional capital investments in our distribution system, these additional positions will also support our work to operate and maintain our existing infrastructure to help ensure continued reliable service in North Dakota.

V. AGIS INITIATIVE

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

A. I describe the Company's Advanced Grid Intelligence and Security (AGIS) initiative, its purpose, the principle components, how they will interact and how they will enable and provide benefits to our customers. I also present the Company's capital and O&M costs for AGIS.

A. Overview

Q. WHAT IS THE AGIS INITIATIVE?

A. AGIS is the Company's multi-year project to create benefits for customers by transforming our distribution system into an intelligent and highly automated system. In this long-term strategic initiative, we modernize and transform our electrical distribution grid to enhance reliability, efficiency, and security, to ensure the safe operation of the grid with the bi-directional flow of energy, and to enable and support improved customer products and services into the future.

The technical capabilities of the current grid are limited compared to more advanced grid technologies, and the overall system is somewhat opaque – meaning the Company has little insight into performance and operation beyond the substation level. AGIS seeks to take advantage of developed and enhanced technologies to increase grid reliability, transparency, efficiency, and access by enhancing grid visibility and creating the infrastructure to support and actualize advanced grid technologies.

Importantly, AGIS will give us tools to enhance our customer experience by providing customers with more in-depth information regarding outages, energy use, system controls, and rate availability. Further, AGIS will help support our clean energy transaction through enhanced enablement of distributed energy resources (DER), optimized demand management, and creating more flexibility for our customers.

Q. WHAT COMPRISES THE AGIS INITIATIVE?

A. The AGIS platform consists of multiple programs utilizing software, hardware, and networks. As I describe further below, we are implementing AGIS through a building block approach. The initial components of AGIS are: (1) our Advanced Distribution Management System (ADMS); (2) our Field Area Network (FAN); and (3) our Advanced Metering Infrastructure (AMI). These three elements will extend our visibility and control of the distribution system from the substation level all the way to our customers' premises. These elements will provide the necessary platform to further enhance the distribution grid through the deployment of field-based applications.

Q. WHAT IS DRIVING THE NEED FOR THE COMPANY'S AGIS INITIATIVE?

A. First, our current meters need to be replaced. Our current automated meter reading (AMR) technology is nearing end of life and our meter reading services vendor, Landis+Gyr (Cellnet) has informed the Company that it will no longer manufacture replacement parts for this system after 2022. Further, our current contract with Cellnet for meter reading services expires at the end of 2025. We have obtained good value from the AMR technology. It has worked efficiently for more than 20 years, but it is now time to move toward a new

solution. Notably, our peers are either in the process of transitioning to smart meters or have already done so.

Second, in light of the need to transition away from our AMR meters, we surveyed the available options and determined that the state of advanced grid technology has reached a point where it is sufficiently mature to be deployed. The Company has implemented some of these technologies in pilot areas and based on the results of those pilots, we believe that it makes sense now to pair replacement of existing AMR meters with a long-term investment in modernizing the distribution system.

While the timing of the AGIS initiative is being driven by the replacement of the AMR meters, the Company's approach is consistent with our broader infrastructure needs. The Department of Energy's Smart Grid System report has recognized the prudence of modernizing the distribution grid:

> Our [country's] electric infrastructure is aging and it is being pushed to do more than it was originally designed to do. Modernizing the grid to make it "smarter" and more resilient through the use of cutting-edge technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts, and restore service faster when outages occur. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Utilities also benefit from a modernized grid, including improved security, reduced peak loads, increased integration of renewables, and lower operational costs.
>
> "Smart grid" technologies are made possible by two-way communication technologies, control systems, and computer processing. These advanced technologies include advanced sensors... that allow operators to assess grid stability, advanced digital meters that give consumers better information and automatically report

outages, relays that sense and recover from faults in the substation automatically, automated feeder switches that re-route power around problems, and batteries that store excess energy and make it available later to the grid to meet customer demand.[1]

Q. ARE CUSTOMERS ALSO DRIVING THE IMPLEMENTATION OF AGIS?

A. Yes. As the Commission is aware, Xcel Energy Inc. provides electric service in eight states.

Based on customer feedback from throughout Xcel Energy Inc.'s large and diverse footprint, we have determined that our customers have an interest in the products (such as focused time-of-use rates) and interoperability (such as the use of distributed energy resources interconnected to the distribution grid) that AGIS provides. Further, as a general rule, customers are always interested in safe and reliable electric service and AGIS will be a key foundation to continued reliable service into the future.

Our analyses indicate that, generally, customers are not interested in the process by which we implement an advanced grid but are interested in the improvements it can bring. In particular, customers appear to be focused on tools for potential energy savings, more detailed and frequent information regarding energy usage, improvements in safety and reliability including less frequent and shorter outages, and, for some business customers, the possibility of advanced rate design.

[1] https://www.energy.gov/sites/prod/files/2019/02/f59/Smart%20Grid%20System%20Report%20November%202018_1.pdf, as of October 1, 2019 (internal citations omitted) (DOE Smart Grid System Report).

Q. WHAT IS THE COMPANY'S STRATEGY FOR AGIS IMPLEMENTATION?

A. We are taking a building block approach to grid modernization. We are starting by putting in place the core components that later allow us to construct and enable more advanced components. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks including the Department of Energy's Next Generation Distribution Platform (DSPx) framework. This approach also allows us to sequence our investments to yield the greatest near-term and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape.

Q. WHAT ARE THE CURRENTLY ENVISIONED BUILDING BLOCKS OF AGIS?

A. We are first planning to install the initial software and hardware solution called the ADMS. With the ADMS in place, the Company will deploy the FAN communications system, which extends the modern grid communications system throughout the distribution system, enabling communication with field devices and AMI meters. As the FAN is deployed to specific areas and AMI supporting systems are deployed, the Company will start deploying AMI meters, which extends communications all the way to each customer's meter. Once ADMS, the FAN, and AMI are in place, the Company will have the foundation in place to expand capabilities and applications.

Q. CAN YOU BRIEFLY DESCRIBE EACH OF THESE COMPONENTS?

A. Yes. I provide a brief introduction to these elements here and provide additional information below:

- **Advanced Distribution Management System**: ADMS will provide an integrated operating and decision software and hardware support

system to allow control room operators, field personnel, and engineers to monitor, control, and optimize the electric distribution system. ADMS gives access to real-time or near real-time data to provide all information on operator console(s) at the control center in an integrated manner and will allow different operating systems and technologies to communicate with each other.

- **Field Area Network**: The FAN is the communications network that will link our existing AMI supporting systems and ADMS software to the AMI meters and new intelligent field devices.
- **Advanced Metering Infrastructure**: AMI is an integrated system of advanced meters, communications networks, and data management systems that enables secure two-way communication between customer meters and utilities' business and operation systems.

Q. UTILIZING THIS BUILDING-BLOCK APPROACH, WHAT IS THE COMPANY'S CURRENT AGIS IMPLEMENTATION SCHEDULE?

A. The Company is currently planning on in-servicing ADMS in 2021 and completing the roll-out of AMI meters in 2024 with FAN implementation occurring approximately six months prior to AMI roll-out. Overall, the Company will be implementing the foundational components of AGIS by 2024 thereby providing the ability to implement further functionality thereafter.

Q. WHAT IS THE COMPANY'S FORECASTED INVESTMENT IN AGIS?

A. The total investment in each jurisdiction will vary based on regulatory approvals for different components. However, given the need to replace our AMR meters, the Company will be implementing ADMS, FAN, and AMI in all orf its jurisdictions by 2025. The Company's currently forecasted total investment in AGIS for NSPM total company is provided in Table 4, below. Table 5 below identifies AGIS capital addition allocated to the North Dakota jurisdiction.

Table 4

AGIS Capital Additions by Year

(NSPM Electric)

(Dollars in Millions)								
AGIS Program	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
ADMS	$9.36	$0.35	$49.45	$0.00	$0.00	$1.67	$2.33	$ 63.16
AMI	4.81	4.90	18.72	130.48	132.41	72.49	14.78	378.59
FAN	0.56	1.84	8.52	43.34	24.80	29.03	0.07	108.16
GIS	1.61	3.61	1.83	1.24	3.06	0.66	1.44	13.45
Other	0.01	3.01	0.00	0.00	0.00	0.00	0.00	3.02
Total*	$16.35	$13.71	$78.52	$175.06	$160.27	$103.85	$18.62	$566.38

* Subject to rounding differences.

Table 5

AGIS Capital Additions by Year

(North Dakota Electric)

(Dollars in Millions)								
AGIS Program	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
ADMS	$0.59	$0.02	$3.07	$0.00	$0.00	$0.00	$0.00	$3.68
AMI	0.10	0.23	0.72	9.43	9.09	0.21	0.10	19.88
FAN	0.03	0.12	0.53	2.75	1.58	1.82	0.00	6.83
GIS	0.10	0.22	0.11	0.08	0.19	0.04	0.09	0.83
Other	0.00	0.19	0.00	0.00	0.00	0.00	0.00	0.19
Total*	$0.82	$0.78	$4.43	$12.26	$10.86	$2.07	$0.19	$31.41

* Subject to rounding differences.

Q. ARE THERE OTHER CONSIDERATIONS THAT THE COMMISSION SHOULD CONSIDER WITH RESPECT TO AGIS?

A. Yes. AGIS is intended to allow us to modernize the distribution system to operate the distribution grid reliably and to provide better service to our customers. Said differently, AGIS is being driven by operational considerations and customer experience considerations.

B. Operational Considerations

Q. ARE THERE OPERATIONAL CONSIDERATIONS SUPPORTING THE DEPLOYMENT OF AGIS?

A. Yes. The foundational components of AGIS will give us increased visibility into the distribution grid, allowing us to operate the grid and detect faults and outages in real-time or near real time. This will allow us to (1) reduce the occurrences and durations of electric outages; (2) optimize the use of the existing distribution grid and enable the installation of field-based devices and applications with which to better operate the system; and (3) manage the

distribution grid as it migrates from one-way power flows to a dynamic, two-way grid.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW ADMS WILL IMPROVE OPERATIONS?

A. ADMS provides for advanced applications, such as FLISR, to be leveraged over time. FLISR, an acronym for Fault Location, Isolation and Service Restoration, uses sensors and software to localize system faults and develop a restoration plan. The restoration plan provides an optimized switching plan (a sequence of operational steps) to assist the operator in quickly restoring power to as many customers as possible, and to direct restoration crews to the best location to begin repair work. When coupled with automated field switches, the switching plan can be executed programmatically to significantly speed restoration. While there are no immediate plans to deploy automated schemes, the foundational tools are ready to accommodate them when the time is right. A subset of FLISR, Fault Location Prediction (FLP), leverages sensor data from substation and field devices to pinpoint the fault location and reduce patrol times needed to physically locate a fault. The existing IntelliTeam system continues to provide value and will be integrated into the FLISR system when appropriate.

Q. WHAT DO YOU MEAN BY VISIBILITY?

A. When I mention visibility, I mean the Company's ability to "see" what is happening on the distribution system from the control room. For example, visibility into outages would mean we can locate the fault on the system causing a customer outage from our control room rather than sending trucks out in the field to determine where the distribution grid was damaged. It also means that we can achieve insights into the load on each component, and

voltage levels at each location throughout the system, by configuring the feeders in ADMS.

Q. DOES THE COMPANY CURRENTLY HAVE VISIBILITY INTO ITS DISTRIBUTION SYSTEM?

A. Yes, but it is limited. We currently monitor the distribution system using the Supervisory Control and Data Acquisition (SCADA) system – a system for remote monitoring and control of telemetered points from substations and distribution automation devices like IntelliTeam switches. We also monitor the distribution grid through customers reporting outages and power quality issues. The Company also currently uses a connectivity model constructed from the Geospatial Information System (GIS) for the Outage Management System (OMS). GIS contains the static physical attribute information about many physical assets that make up the electric distribution system. This model enables outage awareness and improves decision-making when dispatching field personnel to restore power.

Q. DOES THIS LEVEL OF VISIBILITY ALLOW THE COMPANY TO PROVIDE RELIABLE SERVICE?

A. Yes. As I mentioned before, we have been improving our reliability metrics in North Dakota and we provide top tier reliability for our customers. However, our current level of visibility has its limitations. Although, we have been able to successfully operate the system for many years under these conditions, advancements in technology can now support communications between the intelligent devices deployed across the distribution system – up to and including meters at customers' homes and businesses. These advanced

applications cannot be supported with the Company's current field equipment, communication network, and software systems.

Q. WHAT LIMITATIONS DO THE CURRENT MONITORING SYSTEMS HAVE?

A. Functionally, our current field equipment and monitoring systems do not provide us with much visibility beyond the substation, and sometimes feeder level, of the distribution system.

Q. WHY IS THE COMPANY'S VISIBILITY CURRENTLY SO LIMITED?

A. Our visibility in the distribution system is consistent with how the system was designed. Xcel Energy's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer with limited monitoring points. While the Company endeavors to utilize state of the art equipment on its grid, this general design has remained fundamentally unchanged for more than a century, and the design limits the amount of information and visibility that the Company has beyond the substation level. Prior to the technologies which enable a FAN, reliable and feasible communications networks were unavailable. Thus, the system evolved to rely heavily on manual and local control schemes, which served well for the more predictable power flows in the past.

Q WHAT IS THE IMPACT TO THE OPERATION OF THE SYSTEM AND THE CUSTOMER EXPERIENCE GIVEN VISIBILITY EXTENDS ONLY TO THE SUBSTATION LEVEL?

A. Since the existing distribution system only measures limited data on a small number of points on the distribution system (primarily at substations), the Company has little insight into the flow of power, voltages, and the operation

of equipment on the system beyond the substation. Thus, the Company has little insight into the customer experience – the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable and potentially lead to larger reliability issues. To obtain information regarding the numerous distribution system components beyond the substation, such as meter readings, current flow, or voltage levels, the Company must send workers out into the field to gather this information. In addition, the distribution system lacks complete installation of automated controls that allow the Company to adjust and control individual pieces of equipment from a central location.

Q. HOW DOES THIS IMPACT OUTAGE RESPONSE?

A. Since we do not have visibility into the system beyond the substation level, we rely on customers notifying us of outages via phone, website, or smartphone app. Our OMS then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once we know the portion of the system that is out, we must patrol the lines to find the source of the problem. This increases the time and expenses associated with responding to outages and leaves our customers without power for longer periods of time.

Q. HOW DOES THE LIMITED NUMBER OF REMOTELY CONTROLLED DEVICES BEYOND THE SUBSTATION IMPACT OPERATION OF THE SYSTEM?

A. Except for IntelliTeams switches on certain key feeders in Fargo, field switches are manually operated. If there is a fault on any of the many feeder segments that do not have the IntelliTeams switches, the circuit breaker will open at the substation. When this occurs, a field crew must patrol the feeder

to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads. After the crew locates the fault, they manually open immediate upstream and downstream connecting switches to isolate the faulty feeder section. The crews will also close feeder tie switches to reenergize customers (where possible). Finally, after the faulted section of the feeder is repaired, the switches are manually closed to restore service to the feeder. Expanding automation using AGIS will broaden the benefits already experienced as a result of the IntelliTeams switches: customer outage durations will be reduced, there will be quicker responses to faults, and the Company will reduce crew field time.

Q. HAS THE COMPANY BEEN MAKING INVESTMENTS IN AUTOMATED GEAR THAT WILL WORK WITH AGIS?

A. Yes. In addition to the installation of the IntelliTeams switches, one of the steps that we have taken is to use our routine equipment replacements as an opportunity to deploy new equipment that has the greater functionality necessary for a modern grid. An example of this strategy is replacement of electro-mechanical relays with solid-state relays that are communication-enabled and capable of providing fault data that an ADMS system can use to calculate probable fault location. This allows for the location of faults on our system to be more quickly identified thus improving our response time.

We have also been deploying power line sensors on our system that aid our efforts to locate faults more quickly – improving our responsiveness to outage events, and thus the customer reliability experience. Additionally, we have been replacing voltage regulators that have reached the end of their service

life with regulators that have controls that identify reverse-power flow and react accordingly, which will facilitate integration of distributed generation onto the system.

These automated technologies are already providing benefits within our current system using remote control connections. As the AGIS components and applications are implemented, we plan on integrating the existing automated components with ADMS. That integration should require some modifications, but we expect the necessary work to be relatively modest, and the integration will provide additional benefits. For example, as noted above, solid state relays will be able to provide data directly to ADMS. Another example is the IntelliTeams switches which can be integrated into AGIS applications, creating the potential to provide further improvements as a result of being able to move from static rule-based operations to a dynamic operating model.

C. Customer Experience Considerations

Q. HOW WILL AGIS ENHANCE THE CUSTOMER EXPERIENCE COMPARED TO TODAY'S DISTRIBUTION SYSTEM?

A. The advanced grid will be able to provide data and information that is simply not available with our current system and AMR technology. This is not just an incremental step compared to the data provided by our current metering and distribution system technologies; rather, the advanced grid will provide vastly different information with a level of granularity that can impact customers' energy usage decisions, as well as increase reliability and improve the safety and security of the grid.

Q. CAN YOU SUMMARIZE HOW EACH OF THE CORE ELEMENTS OF AGIS IMPACTS THE CUSTOMER EXPERIENCE?

A. Yes. Each of the core elements of AGIS (AMI, the FAN, and ADMS) adds to the customer experience in a specific way, but each is also interdependent upon the others to ensure that maximum benefits can be realized.

AMI provides the customer-level data that will enable an improved customer experience. AMI provides timely and detailed energy usage data, which customers will be able to access through web and mobile applications. Customers will be able to better manage their energy use and will be empowered to control costs.

AMI also provides outage information. The meters will send a "last gasp" message when an outage occurs. These messages are organized to inform our operators where the outage(s) exist. Then, when power is restored, the meters can verify the customer is back in service, which allows us to send accurate notifications to customers about the resolution of an outage.

The FAN is a wireless communications network that includes a mesh network and a communications network that connects the mesh network to back office applications. The primary function of FAN is to enable secure and efficient two-way communication of information and data between the AMI meters and field devices to ADMS and the AMI supporting systems.

In addition to the reliability benefits discussed above, the ADMS will provide insights into power flow that will help prevent overloads from occurring by initiating warnings to the operators, thus reducing the potential for outages.

The ADMS will also provide warnings if voltages exceed allowable ranges, which helps to ensure customer equipment will continue to operate optimally.

Last, the system visibility and data delivered by AMI provides customer benefits in reliability and ability for remote connection, and expanded products and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate, and consistent data from the AMI system will provide insights for customers to make informed decisions about their energy use.

D. Foundational Components of AGIS

Q. YOU DISCUSSED THE FOUNDATIONAL COMPONENTS OF AGIS ABOVE, CAN YOU PLEASE REITERATE THEM HERE?

A. As I mentioned, the Company is taking a building-block approach to AGIS implementation. To that end, we are first making investments to provide foundational elements of the initiative which will improve system control and give us visibility into the distribution system from the substation level all the way to the customers' premises. Using this improved network, we can then layer in additional applications that will maximize the use of this foundation.

The core foundational elements of the AGIS initiative are: (1) ADMS; (2) FAN; and (3) AMI meters.

1. ADMS

Q. WHAT IS ADMS?

A. ADMS is a collection of hardware and software applications that monitor and control the electric distribution system safely, efficiently, and reliably. It is the

centralized system that supports company engineers, personnel in control rooms, and personnel in the field as they monitor, control, and optimize the electric distribution system. ADMS does this by tracking the flow of power on the grid, thereby providing Company employees with visibility into those power flows. ADMS provides immediate benefits for customers and provides a basis for future systems and capabilities.

Q. HOW WILL ADMS ACHIEVE THESE IMPROVEMENTS?

A. ADMS uses an enhanced distribution grid model that will include substations, feeders, taps, and service, in one user interface, to more accurately represent the entire distribution grid. This includes an updated GIS model to provide a geo-spatial electrical model for ADMS. ADMS will be able to maintain the as-operated, and continually updated, GIS electrical model in real-time. This model will provide the Company with greater insight into the distribution system and provide information about at a more granular level than exists today.

Q. WHAT ARE THE CORE APPLICATIONS OF ADMS?

A. The core applications of ADMS are various software programs that enable Company personnel to get real-time information on the state of the grid. Examples include software programs that model the distribution network, analyze how parts of the network related to each other, and calculate impedance. Unlike simpler grid control methods that assume a balanced load, ADMS allows for the more accurate and complex approach in which unbalances can be recognized, analyzed, and corrected. These applications provide the basis for running load flow and state estimation on the distribution system providing near real-time calculations of the state of the network

including factors such as voltages, currents, real and reactive power, voltage drops, and losses.

Using these applications, the Company can provide load flow calculations on the grid, accurately adjusting the calculations with changes in grid topology and insights from sensors. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid.

Q. WHAT INPUTS WILL ADMS RECEIVE AND ANALYZE?

A. ADMS will operate as a centralized system, receiving inputs from devices such as substation remote terminal units, capacitor banks, AMI meters, load tap changers (which regulate the output voltage of a substation transformer), and other distribution automation devices.

Q. WHAT WILL ADMS DO WITH THESE DATA INPUTS?

A. ADMS will take the inputs from these devices and compute the most efficient way for the system to operate and respond to changes. ADMS will also compute the most efficient way for the system to operate based on both manual switching and automated switching (to the extent it is implemented).

More broadly, ADMS will help manage the interaction of outage events, feeder switching operations, and, in the future, advanced applications utilizing intelligent field devices. As a centralized system, ADMS will be able to control the distribution devices in unison and dynamically react to an increasingly complex system in a safe, efficient, and reliable manner. For example, ADMS

will instruct the load tap changers how to regulate voltage based on information about the entire system, rather than just localized information.

When fully deployed, the various operating systems and technologies then on the grid will communicate with and update each other in the ADMS platform. ADMS will adjust for real-time grid conditions and topology that are impacted by each application. For example, ADMS manages FAN and any additional AGIS components that the Company may seek to deploy in the future. That said, even without deployment of advanced grid applications such as FLISR, deployment of ADMS on its own creates benefits for consumers by providing visibility into power flows and other grid conditions.

2. FAN

Q. WHAT IS THE FAN?

A. The FAN is a wireless communications network that includes a mesh network and cellular communications network. The primary function of FAN is to enable secure and efficient two-way communication of information and data between the AMI meters and field devices to ADMS and the AMI supporting systems. The Company will primarily be using cellular communications initially to provide connectivity between our mesh network in the field and the back-office applications while it continues to evaluate other, private options for private network connectivity. The FAN enables back-office applications to directly communicate with field devices providing usage information for both our customers and the Company.

Q. WHAT ARE THE COMPONENTS OF THE FAN?

A. The FAN will consist of two separate wireless technologies: (a) a lower-speed WiSUN mesh network, and (b) use of a cellular solution to provide connectivity between the WiSUN mesh network and the Company's data centers and back office applications.

Q. HOW WILL THE FAN WORK?

A. The FAN will be a single, general-purpose, wide area wireless networking resource that will be capable of simultaneously accessing diverse types of endpoints, each with their own performance requirements on the Company's electric system. These endpoints will include a variety of field devices including reclosers, feeders, electric meters, capacitor banks, and virtually any other field device capable of communications. These endpoint devices also participate in the FAN mesh network by providing connectivity and act as repeaters. Going forward, FAN will be able to communicate with other endpoints as new devices are installed or existing devices are upgraded with communications modules.

Q. PLEASE EXPLAIN WHAT THE NETWORK DEVICES ARE.

A. As noted, the FAN is a highly secure, wireless network. The equipment consists of cellular modems, access points, and repeaters. Access points link the endpoint devices to the communications network and are the equipment that extend the reach of the communications network. Repeaters are range extenders and are used to fill in coverage gaps where devices would be otherwise unable to communicate. These devices will be deployed in strategic locations to pick up signals from field sensors that are then fed to cellular

modems which provide the connection between the access points and back office applications.

Q. HOW DOES THE FAN SUPPORT ADMS?

A. The FAN enables data and information from field devices to be communicated to ADMS, and enables commands to be transmitted to field devices from ADMS.

Q. WHY IS IT IMPORTANT TO IMPLEMENT THE FAN?

A. A communications network is required to support the deployment of AMI meters (which I discuss further, below) and will facilitate the operation of advanced grid applications in the future. Deploying devices that can improve distribution system operations without the FAN would be considerably more expensive to install and operate and would limit the Company's ability to gain full value from their capabilities.

Implementation of the FAN will also provide reliable communication capabilities to all participating field devices, regardless of the device's use. Therefore, the FAN will provide the same, reliable communication to multiple business application and devices. Furthermore, Company ownership of the FAN – as opposed to leased third-party communication networks – will allow the Company to help ensure through measurement and control that the network will consistently satisfy performance, security, and reliability needs.

3. AMI

Q. WHAT IS AMI?

A. AMI is an integrated system of advanced meters, communications networks, and data management systems that enable two-way communications between utilities' business and operational data systems and the meters located at the customers' premises. AMI meters provide substantial data that is currently not available and can be used for both operational and customer benefits that I will describe in more detail below.

Q. HOW IS THIS DIFFERENT FROM THE COMPANY'S CURRENT METER TECHNOLOGY?

A. We have AMR technology in place today. AMR consists of meters equipped with one-way communication modules that transmit meter readings to a fixed radio frequency network. The function of AMR is the collection of meter readings for billing purposes, whereas AMI meters can enable additional operation functions and customer benefits in addition to collecting meter billing reads.

Q. PLEASE DESCRIBE ADVANCED METERS.

A. Advanced Meters are the key endpoint component of an AMI system that measures, stores, and transmits metering quantities, including energy usage information at customer locations.

Q. CAN YOU DESCRIBE THE FUNCTION OF THE ADVANCED METER?

A. Yes. The Advanced Meters can be remotely configured to measure bi-directional and/or time-of-use energy consumption as well as demand. The consumption and demand can be recorded by the advanced meters by time

intervals. While AMI meters in the US are typically programmed for 15- or 60-minute intervals, the Company has planned for the possibility that future applications may require more frequent communication, by specifying a capability as short as five minutes. Advanced Meters have the capability to:

- Measure and transmit voltage, current, and power quality data;
- Detect and transmit meter power outage and restoration events;
- Detect and report meter tampering events;
- More efficiently support distributed generation through remote reconfiguration to measure two-way power flows; and,
- Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module.

Q. HOW ARE THE COMPANY'S CURRENT AMR METERS LESS CAPABLE?

A. The AMR meters have a number of limitations as compared to AMI-capable meters:

- AMR meters have fixed, basic metering functions and are limited to enabling transmission of meter readings for only energy delivered or net energy; another configuration is limited only to delivered energy or demand. In contrast, AMI meters are programmable to meter these energy parameters as well as flexible time of use schedules, reactive energy quantities, and various load profile interval choices.
- AMR meters do not have interval data (load profile) recording capability. For interval data needs, the AMR meter must be swapped with a non-AMR meter that has that functionality and it is either manually read or equipped with a modem for remote reading.
- Current AMR meters do not support time of use rates.

- AMR meters cannot measure and transmit information related to voltage, current, power quality, diagnostics, or outage events.
- AMR meters do not have an internal service switch to provide remote connection (and disconnection) of service.
- AMR meter firmware cannot be upgraded remotely.
- AMR meter configuration cannot be remotely modified (such as from unidirectional to bidirectional, to support distributed generation).

Q. HOW DOES THE FUNCTIONALITY OF AMI ENHANCE THE DISTRIBUTION GRID?

A. As mentioned, AMI meters provide information at customer locations that provide us enhanced visibility into the distribution grid that is currently not possible with our existing meters. The information gathered by the AMI meter and transmitted through the communications system will be available to the Company through head-end software application. In addition to providing customer energy usage information, the AMI meter will provide information that will assist with service outage and restoration. The Advanced Meter will also provide voltage measurement information to assist in load flow and voltage calculations performed by ADMS.

Q. HOW WILL AMI INTERACT WITH ADMS?

A. AMI can provide ADMS with timely real and reactive power measurement data that can be used in system operations. Additionally, and importantly, Advanced Meters will report a power-out or "last gasp" event to the AMI head-end application and report a power-on event when power is restored. This information allows us to detect outages without our customers calling them in and improves our calculations for fault location and restoration activities.

Q. HOW WILL AMI INTERACT WITH THE FAN?

A. The AMI meters will have embedded communication modules that will allow the devices to communicate with the WiSUN network. This will allow data to be transferred between the meters and the AMI back office applications, including interval reads, register reads, voltage information, and power quality data. The FAN will also allow AMI meters to send and receive of commands like power outage notifications. Once fully deployed, the AMI meters will make up over 90 percent of the devices that will communicate as part of the mesh network.

Q. DO AMI METERS REQUIRE THE FAN?

A. The AMI meters do require communications to provide customer data to the back-office applications as well as receive and send messages to the Company on the status of the meter and other useful information. The communications technology proposed (WiSUN) is a widely implemented AMI technology that has proven to be cost effective, reliable, and secure. In contrast, utilizing public cellular exclusive solutions would require the Company to deploy a cellular modem in every meter and pay monthly fees for usage and for the private internet protocol for every device. This alternative would cause the Company to incur substantial monthly and annual expense.

Another significant advantage of pairing AMI meters with the FAN is security. The primary benefits of a private network are having more control over security and resiliency. While not fully private, we have designed the FAN to be segmented, which allows us to keep the WiSUN portion private and the data secure. Further, from a security standpoint, whether public or private, the data

is encrypted as it traverses through the cellular providers' networks. We are working with the cellular provider(s) to understand their security controls and work with their security event teams to ensure appropriate monitoring and action plans are in place to respond to any security incidents or threats.

With respect to resiliency, we plan to work with multiple cellular providers to provide dual network connections at the cellular modems, as many other utilities are doing, to help ensure the loss of one provider's network in one area does not completely shut down our communications. An important consideration in our FAN design strategy is that the WiSUN network we are deploying is a self-healing network that will reroute traffic to different access points and cellular modems if it detects a loss of communication. This will help in reducing the potential impact of an outage by cellular providers and their network. We have also implemented alternate routing of cellular traffic at our data centers in the event the connection between the cellular provider and our data centers is lost. As with any network – including a private network – there is the risk that failures will occur. We will continuously work with our providers to reduce the likelihood and any impact those outages might have on our networks and our customers – especially during storms and other significant events that can have broad impact on networks in a region.

E. Test Year Impacts

Q. WHAT ARE THE COMPANY'S PLANS WITH RESPECT TO AGIS IMPLEMENTATION?

A. The Company began implementation of ADMS in 2017, including enhancement of the GIS. ADMS will be fully placed in-service during the 2021 test year. The Company will begin rolling out the FAN network in 2021

and is expected to complete FAN implementation in 2024. The Company also intends to begin rolling out AMI implementation in 2022 and intends for it to be completed in 2025.

Q. WHAT AGIS CAPITAL ADDITIONS DOES THE COMPANY PLAN FOR THE 2021 TEST YEAR?

A. As noted in Table 5, above, the Company plans North Dakota AGIS capital additions of $780,000 in the current year of 2020. For the 2021 test year, the Company plans North Dakota AGIS capital additions of $4.43 million. A major portion of that total consists of $3.07 million for the in-servicing of ADMS. In addition, approximately $720,000 will be spent on the early stages of the AMI roll-out and approximately $530,000 on the initial installation stages of the implementation of FAN.

Q. WHY ARE THERE CAPITAL ADDITIONS FOR AMI AND FAN BEFORE THOSE ASPECTS OF THE AGIS INITIATIVE ARE ROLLED-OUT IN NORTH DAKOTA?

A. The wholesale replacement of customer meters and the implementation of a large and distributed communication system are both large and complex projects. In advance of the large-scale physical installation efforts, the Company must undertake a variety of tasks including project management, planning activities, and testing.

Q. WHAT ARE KEY DRIVERS OF THOSE FORECAST CAPITAL ADDITIONS?

A. For the test year, as noted above, the key driver is bringing ADMS into service. However, as AGIS is put into place between now and 2025, the largest portion of the capital additions will be the installation of the advanced meters. Of approximately $31.41 million in AGIS capital additions forecasted for North

Dakota between 2019 to 2025, $19.88 will consists of AMI costs. The second largest portion is FAN at $6.83 million. Both FAN and AMI involve the Company purchasing and installing a large number of individual devices. Table 6 below shows AGIS capital additions from 2019 to 2025 on a North Dakota jurisdictional basis.

Q. WHAT TYPES OF O&M COSTS WILL THE COMPANY INCUR TO IMPLEMENT THE AGIS INITIATIVE?

A. The forecasted AGIS O&M expenses for the 2021 test year are shown in Table 6 and Table 7, below.

Table 6

AGIS O&M (NSPM Electric)

(Dollars in Millions)

AGIS Program	2019	2020	2021	2022	2023	2024	2025	Total
ADMS	$ 1.23	$ 1.63	$ 3.50	$ 3.48	$ 2.53	$ 2.37	$ 2.30	$ 17.04
AMI	0.28	1.54	6.28	9.79	10.22	9.88	7.85	45.84
FAN	0.06	0.07	1.35	1.41	0.87	0.82	0.27	4.85
GIS	-	-	-	-	-	-	-	-
Other[1]	0.96	8.35	8.90	13.87	20.75	20.48	21.00	94.31
Total	$ 2.53	$ 11.59	$ 20.03	$ 28.55	$ 34.37	$ 33.55	$ 31.42	$ 162.04

[1]Includes AMI head end shared asset allocation.

*There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.

Table 7

AGIS O&M (ND Electric)

(Dollars in Millions)

AGIS Program	2019	2020	2021	2022	2023	2024	2025	Total
ADMS	$ 0.08	$ 0.10	$ 0.21	$ 0.20	$ 0.14	$ 0.13	$ 0.13	$ 0.99
AMI	0.02	0.07	0.25	0.40	0.40	0.33	0.20	1.67
FAN	-	-	0.08	0.09	0.05	0.05	0.02	0.29
GIS	-	-	-	-	-	-	-	-
Other[1]	0.06	0.15	0.34	0.83	1.31	1.28	1.31	5.28
Total	$ 0.16	$ 0.32	$ 0.88	$ 1.52	$ 1.90	$ 1.79	$ 1.66	$ 8.23

[1]Includes AMI head end shared asset allocation.

*There may be differences between the sum of the individual AGIS program amounts and Total amounts due to rounding.

Q. WHAT ARE THE KEY DRIVERS FOR THE TEST YEAR AGIS O&M EXPENSES?

A. There are two main drivers with respect to AGIS O&M: (1) program management and implementation costs; and (2) software and hardware maintenance costs.

Q. PLEASE DESCRIBE THE IMPLEMENTATION AND PROGRAM MANAGEMENT COSTS.

A. AGIS is a complex, multidisciplinary, long-term program. Designing, sourcing, and implementing AGIS requires us to coordinate with may internal and external subject matter experts, vendors, and program managers. AGIS program management costs directly related to a capital addition are capitalized to a particular project, just like the Company would do for any large capital project like building a wind farm. That said, with an initiative the size and scope of AGIS, the Company must manage the integration of all components. Consequently, those program management costs that cannot appropriately be capitalized are recorded as an O&M expense. Program

management costs are mainly reflected in the "Other" category in the tables above.

Q. PLEASE DESCRIBE THE HARDWARE AND SOFTWARE MAINTENANCE O&M EXPENSE.

A. Once implemented, AGIS will be a system of hardware and software that needs to be maintained. These types of expenses are no different than hardware and maintenance expenses we incur today for our computers, communication networks, and other information technology. Our O&M expenses will increase somewhat during the deployment of AMI as a result of a ramping up of the installation of meters but are then expected to stabilize.

Q. WHY ARE O&M EXPENSES INCREASING THROUGH 2025?

A. Once the implementation phase of AGIS is completed through the roll-out of AMI meters in 2023, we expect our O&M expenses to stabilize. Our out-year forecasts include a material contingency to ensure that we have the necessary funds for the resources and maintenance that will be needed for the AGIS assets. Approximately $7 million of the Company-wide AGIS O&M expense forecasts in 2023-2025 are related to this contingency. When the contingency is accounted for, AGIS O&M expenses are more in-line with the test-year costs.

Q. What is your recommendation with respect to AGIS?

A. I recommend that the Commission approve our request to recover the test year capital investments and O&M expense for the foundational components of AGIS that we propose to implement during the test year.

Our proposal includes full ADMS implementation (including associated applications) and the first set of investments in the FAN.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Distribution capital investments and O&M budget presented in this rate case. These capital investments are needed to continue to provide safe and reliable service to our customers while replacing infrastructure that has reached the end of its life, responding to localized areas of demand growth, extending service to new customers, and relocating facilities as needed. To support these capital investments and to maintain our existing assets, our O&M expenditures are reasonable and necessary. The AGIS investments and O&M expenditures will give customers greater information and control over their own energy usage while also promoting the reliability, efficiency, and security of the grid.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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
Kelly A. Bloch

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.

Kelly A. Bloch

Kelly A. Bloch

Subscribed and sworn to before me, this 21 day of October, 2020.

Steven D. Spiess

Notary Public
My Commission Expires: January 31, 2025

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

Statement of Qualifications

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Ms. Bloch has more than 29 years of experience in the utility industry where she has compiled a diverse background. She joined Public Service Company of Colorado in 1991 and served in various engineering roles in the four operating companies at Xcel Energy: Manager of Capacity Planning for Xcel Energy, Manager of Distribution Planning for Public Service, Manager of System Planning and Strategy, and Senior Director Electric Distribution Engineering, in addition to her current role.

Ms. Bloch is currently the Regional Vice President, Distribution Operations, for Northern States Power Minnesota and Northern States Power Wisconsin. She is responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of North Dakota, South Dakota, Minnesota, Wisconsin and Michigan.

Resume

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Education:

Bachelor of Science Electrical Engineering
South Dakota State University

Employment:

Xcel Energy Services

2015-Present	Vice President, Distribution Operations NSPM/WI
2014-2015	Sr. Director, Electric Distribution Engineering
2012-2014	Manager, System Planning and Strategy
2005-2009	Manager, Distribution Capacity Planning
2002-2005	Sr. Engineer, Distribution Capacity Planning

Public Service Company of Colorado

2009-2012	Manager System Planning
1993-2002	Sr. Engineer, Distribution Reliability Assessment
1991-1993	Distribution Standards Engineer