Direct Testimony and Schedule
Joni H. Zich

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 Natural Gas Service in North Dakota

Case No. PU-21-____
Exhibit___(JHZ-1)

Gas Operations

September 1, 2021

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Schedule

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Joni H. Zich. I am the Senior Director, Strategy, Governance and Planning for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company (NSP), a Minnesota corporation and an operating company of Xcel Energy Inc. (Xcel Energy) that provides natural gas service in North Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have both a Bachelor of Business Administration and a Master of Business Administration from the University of Wisconsin–Eau Claire. I have been employed by Xcel Energy or one of its operating companies for over 30 years. Throughout my career, I have worked in the areas of energy conservation, account management, gas scheduling, trading, and management of upstream interstate transportation and storage services. In 2012, I was promoted to Director, Business Operations and System Strategy Planning. In this role, I am responsible for the strategy and long-term planning of Xcel Energy's gas system. My duties include strategic planning for Xcel Energy's gas operations business unit, managing gas cost recovery mechanisms for integrity management riders, directing all aspects of Public Service Company's gas transportation services, and leading long-term capacity planning for the Company's high-pressure gas systems. In January 2021, I also began directing the Company's gas governance organization, which includes gas standards, compliance, contractor inspections, quality assurance, and the Pipeline Safety Management System (PSMS), where I was promoted to Senior Director,

Strategy, Governance and Planning. A description of my qualifications, duties, and responsibilities is provided as Exhibit___(JHZ-1), Schedule 1.

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

A. The purpose of my Direct Testimony is to support the revenue requirement increases attributable to the Gas Operations (Gas Ops) system investments and O&M expenditures that are driving the need for this rate case.[1] The Company has made significant capital additions to its gas distribution system since its last natural gas rate case, which was filed 15 years ago (Case No. PU-06-525 using a 2007 test year) (2007 Rate Case). I discuss how these investments have been driven by strong customer growth in our North Dakota service territory, as well as our ongoing work to enhance the safety and reliability of the service we provide to our North Dakota customers.

In particular, I provide support for the Company's Fargo/West Fargo capacity expansion project (Fargo Capacity Project) to meet the natural gas demand needs of North Dakota customers into the future. I also support our current investments in the Company's gas peaking plants, as well as our ongoing investments to support new business, safety, system reliability, and mandated relocations. Finally, I also address changes in Gas Ops O&M costs since the 2007 Rate Case.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section I* – Introduction
- *Section II* – Gas Utility Overview

[1] Company witness Ms. Laurie J. Wold discusses other capital additions included in the revenue requirement.

- *Section III* – Fargo Capacity Project
- *Section IV* – Peaking Plant Investments
- *Section V* – Gas Operations O&M Expenses
- *Section VI* – Conclusion

II. GAS UTILITY OVERVIEW

A. North Dakota Gas Operations

Q. PLEASE PROVIDE AN OVERVIEW OF NSP'S GAS OPERATIONS IN NORTH DAKOTA.

A. NSP provides natural gas sales and transportation service to approximately 60,000 residential, commercial, and industrial customers in North Dakota in the cities of Fargo, West Fargo, Grand Forks, and several surrounding communities. We operate distribution facilities to serve our North Dakota customers in three counties within the state. This includes approximately 1,100 miles of distribution mains and over 60,000 meters, as well as regulator stations and other supporting infrastructure. The Company provides natural gas utility services in North Dakota as part of the NSP gas system, operated as an integrated retail natural gas procurement and delivery system that serves the Company's gas customers in portions of both North Dakota and Minnesota.

Q. WHAT ARE THE PRIMARY GAS OPS FUNCTIONS?

A. Gas Ops provides all the major functions to deliver natural gas from upstream interstate pipelines to the customer's meter, and ensures public safety through compliance with state and federal pipeline safety regulations. These functions include: planning, engineering, design, locating, construction, operations and

maintenance, metering, and emergency response, to name a few. Gas Ops also coordinates with communities to relocate our facilities when necessary for municipal projects like water and sewer projects and complying with all state and federal regulations.

Q. WHAT ARE SOME OF THE SIGNIFICANT CHANGES TO THE COMPANY'S GAS SYSTEM AND BUSINESS SINCE THE 2007 RATE CASE?

A. First, while the Company has continued to serve the same North Dakota communities as in the past, the size of our business and natural gas system in North Dakota has grown over this time. The number of retail customers we serve in North Dakota has increased by approximately 40 percent, from 43,000 as of our 2007 Rate Case to 60,000 currently. As a result, between 2007 and 2020, the Company added 16,075 new gas services and approximately 267 miles of new distribution main in North Dakota. Further, the local growth in the Fargo/West Fargo area was the primary driver of the need for the Fargo Capacity Project detailed in Section III below. Customer growth has also resulted in additional work as we have responded to increasing customer underground locate requests and gas emergency calls.

At the same time, we have enhanced the safety and reliability of the service we provide to our North Dakota customers. While we continue to invest in routine system maintenance and respond to customer growth needs, we have also enhanced system integrity with capital investments to help ensure public safety, consistent with evolution of the industry and federal and state regulations that have emerged during the past 15 years.

Q. WHAT ARE SOME OF THE CHANGES IN INDUSTRY REGULATION THAT HAVE OCCURRED SINCE THE COMPANY'S LAST RATE CASE?

A. We have seen important changes in industry rules, requirements, and best practices. For example, in 2009, the Pipeline and Hazardous Materials Safety Administration (PHMSA) published the final Distribution Integrity Management Program (DIMP) rule establishing integrity management requirements for gas distribution pipeline systems. The Company implemented a program and plan in 2011 to comply with DIMP requirements, and beginning in 2022, the Company plans to make annual, programmatic investments in renewing aging mains and service pipe.

Subsequently, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011[2] (2011 Pipeline Safety Act) was signed into law on January 3, 2012, leading to additional requirements and development of further industry practices to protect the safety and integrity of natural gas infrastructure. These requirements call upon gas utilities to make investments to replace aging materials and historical construction practices through main and service renewals, as well as data gathering and management that did not previously exist for aging infrastructure. During this same timeframe, in 2012, the Company established a separate gas business unit, resulting in an increased focus on public safety and enhanced expectations for its gas distribution and transmission systems.

In North Dakota, the Commission oversees pipeline safety and has generally adopted the federal regulations, including those outlined above. In addition,

[2] https://www.govinfo.gov/content/pkg/PLAW-112publ90/pdf/PLAW-112publ90.pdf.

the Commission further oversees and regulates one-call excavation rules, ensuring public safety through the proper marking of underground facilities. Rules, regulations, and industry standards governing safety in the industry continue to evolve. Over the last 15 years, we have worked to maintain alignment with applicable regulatory requirements and industry best practices while avoiding the need for gas rate cases, despite increasing regulation and rising costs.

B. The NSP Gas System

Q. PLEASE DESCRIBE THE NSP GAS SYSTEM THAT SERVES NORTH DAKOTA.

A. The overall NSP gas system consists of pipelines, storage facilities, and natural gas plants that work together to deliver natural gas to our local distribution systems in both Minnesota and North Dakota. The Company provides natural gas utility services to its customers in portions of North Dakota and Minnesota, and makes unified purchasing and transportation decisions for its customers in these states. Where possible, NSP distribution system costs are directly assigned. Other costs, mainly those related to serving customers in both states, are allocated between the states as described by Company witness Mr. Benjamin C. Halama.

Q. HOW DOES NSP PROCURE NATURAL GAS TO SERVE ITS CUSTOMERS IN NORTH DAKOTA?

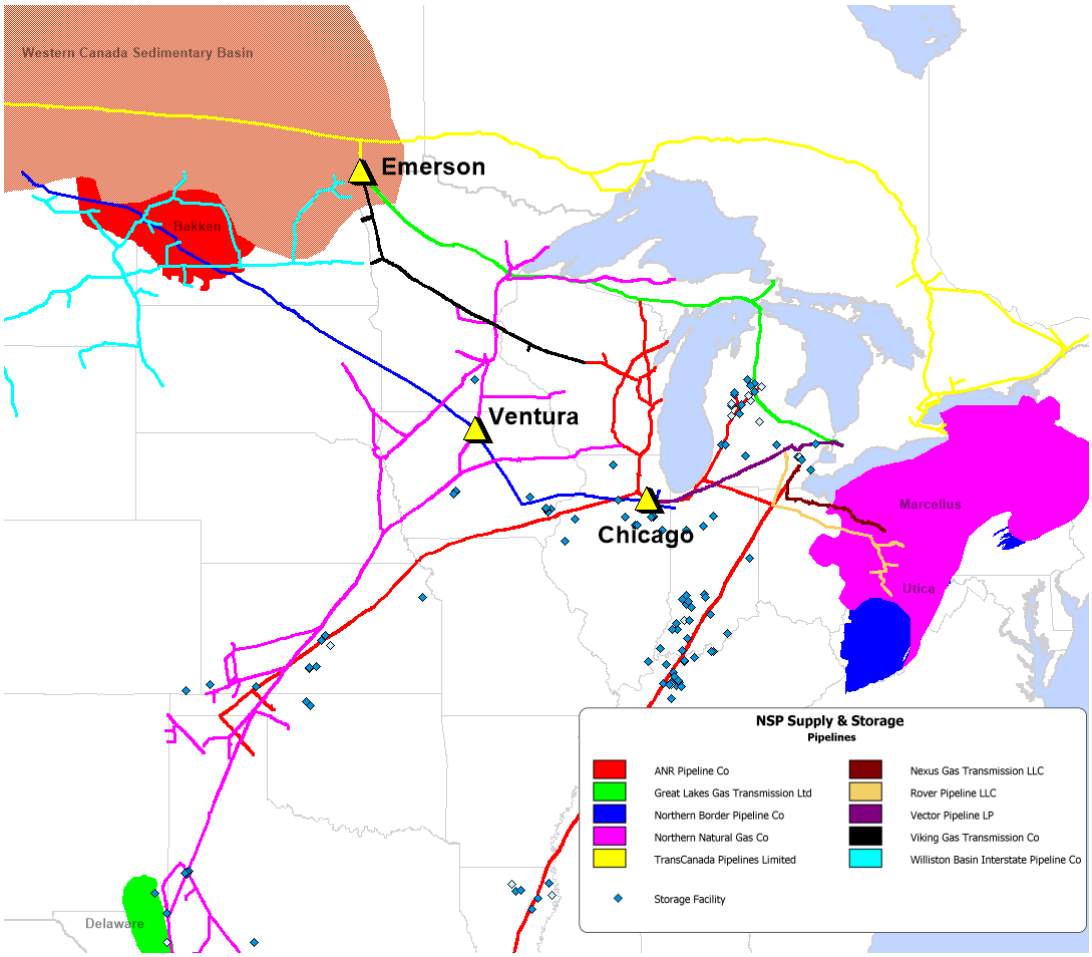
A. As noted above, the overall gas system allows for unified purchasing and transportation of natural gas for NSP gas customers, including those in North Dakota. This enables efficient natural gas acquisition and delivery functions, which lowers costs for all of our natural gas retail customers. Natural gas is

then transported by interstate pipelines to our NSP distribution systems, including those in the Fargo and Grand Forks service areas.

Specifically, NSP purchases the natural gas that it provides to customers in North Dakota and Minnesota through a combination of baseload contracts and daily spot market purchases at four different hubs: the Ventura Hub, the Demarcation Hubs, the Emerson Hub, and the Chicago Hub. This diversity in purchasing locations provides the Company with flexibility, which helps to keep gas costs low. Natural gas from the Bakken formation is transported through the Northern Border Pipeline Company (Northern Border) system to the Ventura Hub located in Hancock County, Iowa, which is where Xcel Energy purchases the majority of its natural gas from the Bakken formation. The Demarcation Hub is located north of Clifton, Kansas, and at that location the Company purchases natural gas from the Southwestern United States. Natural gas from Canada is available at the hub in Emerson, Manitoba, and the Company also purchases natural gas at the Chicago Hub. Figure 1 below shows the interstate pipelines serving the NSP gas system, as well as the location of the hubs from which the Company purchases natural gas for our customers.

Figure 1

NSP Supply and Storage



Q. CAN YOU PROVIDE MORE EXPLANATION REGARDING HOW PURCHASED NATURAL GAS IS TRANSPORTED TO THE COMPANY'S NORTH DAKOTA CUSTOMERS?

A. Yes. The Company's North Dakota natural gas distribution systems are connected directly to two interstate pipeline systems: Viking Gas Transmission Company (Viking) and Williston Basin Interstate Pipeline Company (WBI). Those pipelines are non-affiliated pipelines regulated by the Federal Energy Regulatory Commission (FERC). However, the WBI pipeline

is not of sufficient size to serve North Dakota customers in its own right. Therefore, the integrated system also utilizes transportation services on several other interstate pipelines, as shown in Figure 1. For example, the Company uses upstream transportation and underground storage services on several interstate gas pipelines that connect to Viking to serve its North Dakota customers, including those owned by Northern Natural Gas Company, ANR Pipeline Company, Great Lakes Gas Transportation Limited, and Northern Border (as discussed above).

Q. IN ADDITION TO THE INTERSTATE PIPELINES, IS THERE OTHER INFRASTRUCTURE THAT SUPPORTS OPERATIONS OF THE NSP GAS SYSTEM?

A. Yes, the Company also incorporates use of underground storage services available on several interstate pipelines, as well as the Company's peaking plants, which provide additional capacity for the gas system.

Q. PLEASE DESCRIBE THE STORAGE FACILITIES UTILIZED BY THE COMPANY.

A. As shown in Figure 1 above, there are upstream underground natural gas storage facilities that the Company contracts to provide flexible withdrawal capability to respond to varying system demand. These storage facilities are located in Michigan, Kansas, and Iowa. The Company purchases and stores supply when pricing is optimal (primarily during the low-use summer months), thus being able to rely on this lower-cost supply when customer demand ramps up during cold weather. This underground storage provides flexibility, allowing the Company to respond to customer demand fluctuations outside of contracted supply purchases without having to rely on spot market purchases where pricing may be more volatile.

Q. PLEASE DESCRIBE THE COMPANY'S PEAKING PLANTS.

A. NSP owns and operates three above-ground peak shaving facilities ("peaking plants") located in Minnesota, including the Wescott Liquefied Natural Gas (LNG) plant and the Sibley and Maplewood Propane Air plants. These plants essentially store liquefied natural gas or propane gas that can be vaporized and injected into the system to help meet firm customer requirements on the coldest winter days. These peaking plants are largely a capacity resource, as they are designed to be utilized on a limited basis to meet demand for our firm customers as the Company approaches Design Day conditions.[3] The existence of these plants on our integrated system supports service to all customers, including those in North Dakota, by reducing the need for other pipeline capacity and supply purchases. I discuss these peaking plants and the associated recent capital investments further in Section IV below.

Q. HOW DOES OPERATION OF THE BROADER NSP GAS SYSTEM BENEFIT THE COMPANY'S NORTH DAKOTA CUSTOMERS?

A. The diversity of market centers, access to multiple supply points and storage facilities, and the peaking plants provided by the overall NSP gas system deliver value for our North Dakota customers that would be unavailable if served by a separate, stand-alone gas system. Both the size of the NSP gas system, serving approximately 530,000 customers (of which 60,000 are located in North Dakota), and the geographic area covered contribute to these benefits.

[3] A Design Day refers to a 24-hour period of the greatest possible gas requirement to meet firm customers' needs. I discuss Design Day modeling further in Section III.

Q. PLEASE EXPLAIN FURTHER.

A. Upstream interstate transportation, contracted underground storage facilities, and Company-owned, above-ground peaking plants across the NSP system provide value with respect to system reliability and safety for our North Dakota customers. For example, during an emergency, like the TransCanada explosion that occurred on January 25, 2014 on the Emerson lateral that delivers gas to Viking, the Company was able to use a combination of interstate pipeline transportation on Northern Natural Gas and ANR pipeline and storage from both its contracted underground storage facilities and its above-ground peak shaving plants to deliver natural gas to North Dakota. Without this combination of assets, it is likely that customers in North Dakota would have experienced a gas outage (loss of heat) during a period of below zero temperatures.

C. Overview of Capital Investments

Q. WHAT DRIVES THE COMPANY'S CAPITAL INVESTMENTS IN ITS NORTH DAKOTA GAS DISTRIBUTION SYSTEM?

A. The focus of our capital investments has been and remains our mission to provide safe and reliable service to our customers. Our safety work focuses on compliance with federal and state pipeline safety standards and industry best practices to protect the public and the natural gas system. Our reliability work addresses capacity needs to help ensure adequate and reliable service to firm customers during peak hour design conditions. Peak hour refers to the highest hourly flow rate for the system on a Design Day. We also incur costs to connect and serve new customers, and to relocate existing natural gas facilities required by the governing authority or that are in direct conflict with

street expansions within public rights-of-way. Finally, we incur costs to maintain the LNG and propane plants that serve the NSP system.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION REGARDING THE TYPES OF GAS OPS CAPITAL INVESTMENTS?

A. Yes. Our capital investments are broken into the five categories described below:

Safety: Maintaining safety requires a multi-faceted work and capital investment approach that takes into account the complex nature of the system, the multiple risks that face any natural gas system, and the requirements of the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration. Much of the Company's safety work is focused on maintaining the integrity of its gas system assets. This also includes work on our infrastructure to reduce leaks, improve public safety (such as our program to move meters that are inside customer premises to an outside location), and renew service mains and pipes.

Reliability: Maintaining a reliable system requires identification of capacity needs to serve firm customers on a peak design hour. The peak design hour reflects temperature extremes of -37ºF for Fargo and -40ºF for Grand Forks. Reliability initiatives include larger pipeline capacity-building investments like the Fargo Capacity Project or smaller routine asset health and capacity investments.

New Customer Business: The Company has the obligation to serve new customers that request gas service within its service territory under its tariff

rules. When there is no existing connection to the customer's property, the Company must establish or update customer records and make capital investments to install new service lines, meters, and other infrastructure to extend service to the residential, commercial, or industrial property.

Mandatory Relocations: The Company is required to move existing infrastructure to meet federal, state, and/or local requirements. This includes relocating facilities required by a governing authority or that are in direct conflict with street expansions within public rights-of-way. The Company must invest capital to achieve these relocations and re-establish service via infrastructure at a different location.

Peaking Plants: The Company has three gas peaking plants – one LNG plant, (Wescott), and two propane plants (Sibley and Maplewood). These plants help ensure that the Company has adequate capacity to serve firm customers during periods of cold weather or during other operational or market issues. These plants are discussed in Section II above and in further detail in Section IV below.

Q. PLEASE PROVIDE AN OVERVIEW OF THE GAS OPS CAPITAL ADDITIONS FROM 2007 TO 2022.

A. Table 1 below reflects the Gas Ops capital additions (i.e., infrastructure placed in service) from 2007 through 2020, and the forecasted capital additions for 2021 and the 2022 test year. This information is shown in categories for which we can provide comparative data over this extended period.

Table 1

2007-2022 Gas Capital Additions (Millions)

State of North Dakota (includes AFUDC)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Peaking Plants	0.1	0.3	0.0	0.1	0.1	0.0	2.5	0.2	0.0	1.0	0.2	0.1	0.1	0.5	3.4	2.5
Transmission	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.4	0.1	0.0	0.0	0.1	0.2	0.3	0.0	0.0
Distribution	1.7	1.8	6.2	4.9	1.4	3.6	5.2	5.3	6.4	5.9	6.9	8.2	8.6	10.6	36.7	13.8
General and Intangible	1.0	0.5	0.8	0.7	0.5	0.4	0.4	0.4	0.5	0.6	0.4	1.3	0.8	0.9	1.9	1.5
Total	**2.8**	**2.6**	**7.0**	**5.7**	**2.0**	**4.0**	**8.1**	**6.3**	**7.0**	**7.5**	**7.5**	**9.7**	**9.7**	**12.3**	**42.0**	**17.8**

Q. WHAT DOES TABLE 1 INDICATE REGARDING GAS CAPITAL INVESTMENT OVER TIME?

A. Overall, capital investments have increased over the past 15 years due primarily to customer growth, with some variance on a year-to-year basis depending on the specific work that is necessary to meet the gas requirements of our customers and ensure the safety of our customers and employees. Much of the work is routine distribution system work, consisting primarily of many smaller investments in new or renewed gas services and mains, with other work consisting of larger discrete projects. For example, looking backward, in 2013 and 2016 we made some larger investments in our peaking plants, as I describe in Section IV of my Direct Testimony, in addition to investments related to customer growth. Customer growth has continued and, beginning in 2018 and 2019 through the present, we specifically increased investment in North Dakota to help ensure continuing system reliability.

Q. CAN YOU EXPLAIN FURTHER WHY CAPITAL ADDITIONS ARE INCREASING OVER TIME?

A. Yes. While the Company's gas system in North Dakota has performed very well over time, beginning in 2018, we began increasing distribution system

investments in North Dakota to help ensure continuing service, safety, and reliability. A key driver of these investments was new customer growth. In 2018, for example, routine new business activity relating to installation of new mains, services, and meters accounted for $4.8 million of the $8.2 million total distribution investment. More recently, we have also been working on larger projects and programmatic work to meet more recent system and customer needs, particularly by way of the non-recurring Fargo Capacity Project (which accounts for $27.5 million of the $36.7 million in capital additions in 2021 and is described in Section III of my Direct Testimony), and refurbishing the Company's peaking facilities (described in Section IV of my Direct Testimony). In 2022 and beyond, after completion of the Fargo Capacity and peaking facility projects, we are initiating or ramping up programmatic system safety and reliability work to serve North Dakota customers, including our multi-year Inside Meter Move Out, DIMP, and meter Module Replacement programs.

Q. WHAT ADDITIONAL SAFETY WORK IS THE COMPANY PLANNING FOR 2022?

A. The Company's safety work is focused largely on routine work and discrete projects to help ensure system integrity – avoiding system leaks and protecting public safety. As I mentioned, larger discrete projects in 2022 include the upcoming DIMP and Inside Meter Move Out programs.

Q. WHAT ARE THE COMPANY'S PLANNED DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM INVESTMENTS?

A. DIMP projects address our aging gas infrastructure's structural integrity, renewing infrastructure to help ensure a safer gas system that will reduce the likelihood of incidents within the community. The Company's DIMP work

is targeted towards removing identified higher-risk gas infrastructure materials (e.g., bare steel or vintage plastic) and replacing them with modern materials. As we complete other discrete projects in 2021, we are increasing this work in 2022 and beyond, and plan to replace approximately six miles of poor performing main and 600 services annually.

Q. WHAT IS THE INSIDE METER MOVE OUT PROGRAM?

A. The Inside Meter Move Out program will move most of our gas meters still located inside of customer premises to outside locations, and replace the existing facilities with new meters, connections, and regulators. The relocation of meters outside of a customer's premise ensures accessibility to meters as required by federal code and allows the Company to more efficiently perform routine required inspection and maintenance of these meters without having to coordinate access or inconvenience the customer. Additionally, moving the meters to outside locations where possible reduces the risk of gas accumulating in a confined space, where there are more sources of ignition. We have determined that there are over 550 meters located inside customers' premises in the state of North Dakota that can be moved outside. This program will move these meters to outside locations over a period of five years, beginning with approximately 100 meters in 2022.

Q. WHAT ADDITIONAL RELIABILITY WORK IS THE COMPANY UNDERTAKING?

A. The reliability category includes routine work to renew mains, services, and other infrastructure to help ensure system infrastructure has the capacity necessary to serve North Dakota customers. In addition, the Company will begin the Module Replacement program to enhance metering reliability.

Q. WHAT IS THE MODULE REPLACEMENT PROGRAM?

A. The Module Replacement program will address replacement of current automated meter reading (AMR) technology. This work is necessary because the Company's agreement with our meter reading provider will expire December 31, 2025, and the current technology will no longer be supported. The Company will replace the existing equipment with modules that enable drive-by meter reading. In some cases the meter will need to be replaced rather than the module only. The new modules will be owned by the Company, and once installed, drive-by meter reading will be performed by the Company, phasing out meter reading done by the current AMR provider. The program will begin in 2022 and conclude in 2025.

Q. PLEASE SUMMARIZE NEW BUSINESS PROJECT INVESTMENTS.

A. New customer business projects include the costs of providing and installing mains, service lines, meters and other infrastructure necessary to connect a new customer to the Company's natural gas system. Costs include routine work, consisting of new customer additions based on forecasted customer growth, and larger, discrete projects that are in excess of $300,000. The new business capital additions are primarily routine projects consisting of smaller customer connection work that is conducted routinely over time. Occasional discrete projects might include connecting a new subdivision or larger commercial customer, but more typically, new business fluctuates based on routine customer requests for connection.

Q. PLEASE SUMMARIZE MANDATORY RELOCATION INVESTMENTS.

A. Mandatory relocations are capital projects that require the Company to move existing infrastructure in order to meet federal, state, or local requirements.

This includes relocating facilities for safety-related work required by a governing authority or that are in direct conflict with street expansions within public rights-of-way. For example, in 2020 and the first months of 2021, the Company completed relocations in the communities of Casselton, Fargo, Grand Forks, Horace, and West Fargo. All of the capital investments described above are necessary to continue to provide safe and reliable gas service to our North Dakota customers.

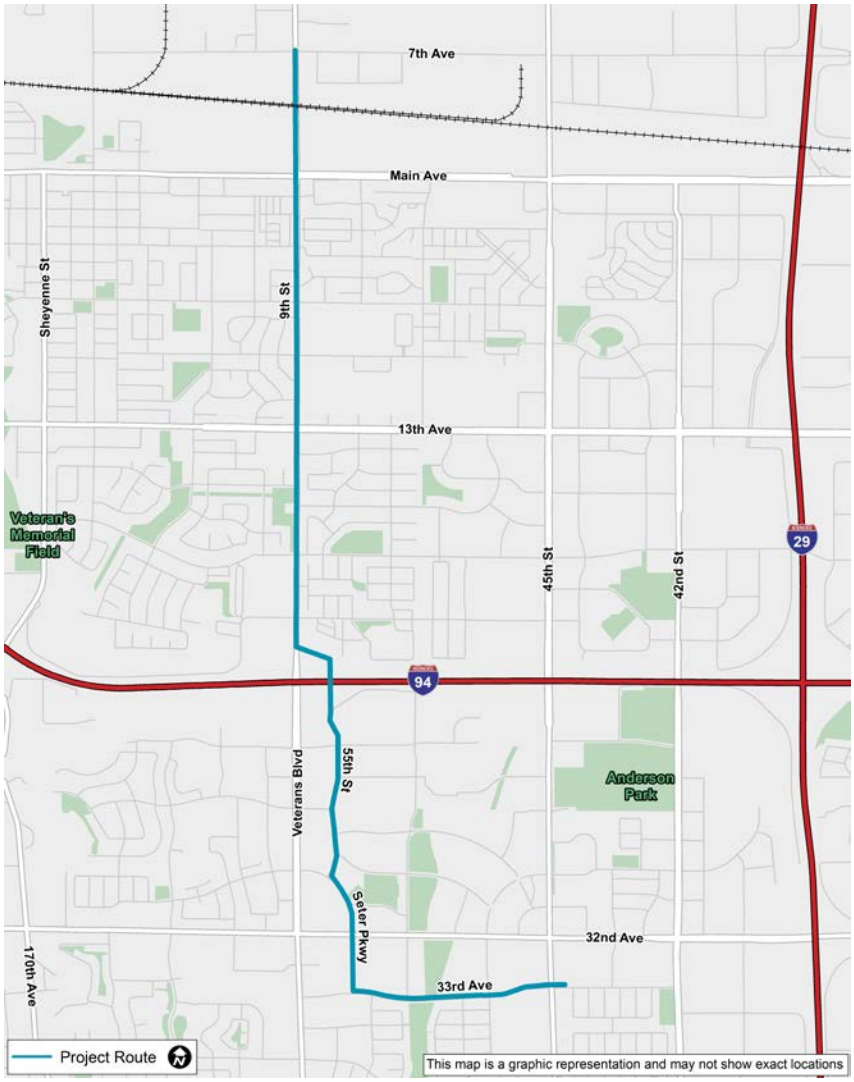
III. FARGO CAPACITY PROJECT

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENT IN THE FARGO CAPACITY PROJECT.

A. The Fargo Capacity Project will increase natural gas distribution capacity within the Fargo, West Fargo, and Horace service areas to continue to meet customer growth in the area. The Fargo Capacity Project will allow the Company to continue to serve existing and forecasted new customers and will improve reliability and system resiliency during extreme cold weather. The project consists of constructing a 12-inch pipeline approximately 4.5 miles long running along 9th Street in West Fargo, under Interstate 94, and along 55th Street South, Seter Parkway, and 33rd Avenue in Fargo. A map showing the location of the Fargo Capacity Project is provided in Figure 2 below. Construction began in May of 2021, and the project is expected to be in-service in November 2021.

Figure 2

Fargo Capacity Project Map



Q. IS THIS THE SAME PROJECT THE COMPANY HAS PRESENTED TO THE COMMISSION BEFORE?

A. Yes. The Company provided a project description and cost estimate in its January 14, 2021 petition in Case No. PU-21-35, requesting a jurisdictional determination by the Commission regarding project certification and siting requirements. On February 17, 2021, the Commission issued a letter

confirming the project is not classified as a "transmission line" under North Dakota law and federal statutory definitions, and as such, certification requirements do not apply to the project. Prior to making that filing, the Company presented project information to the Commission at an informational hearing held on October 7, 2020, addressing the need for the project and providing project details.

Q. HAS THE PROJECT SCOPE OR COST ESTIMATE CHANGED SINCE THE COMPANY'S OCTOBER 2020 PRESENTATION OR JANUARY 2021 FILING WITH THE COMMISSION?

A. There have been no material changes to the project or construction timing previously provided by the Company. The initial estimate of approximately $28 million was a planning phase estimate and is consistent with the capital additions reflected in this case.

A. Need for the Project

Q. WHY IS THE FARGO CAPACITY PROJECT NEEDED?

A. The Fargo Capacity Project is needed to continue to reliably serve the Fargo/West Fargo area now and into the foreseeable future. In light of strong customer growth in the area, the existing system is nearing its full capacity and further expansion is necessary. The inadequacy of the current local distribution system has already been evidenced by our need to employ compressed natural gas (CNG) trailers in the Fargo area during the winter of 2020/2021 to maintain adequate system pressures for existing firm customers on the coldest of days. The Fargo Capacity Project will help ensure reliable service to existing firm customers during cold winter weather, reduce O&M costs associated with the CNG trailers, and provide the capacity for service to

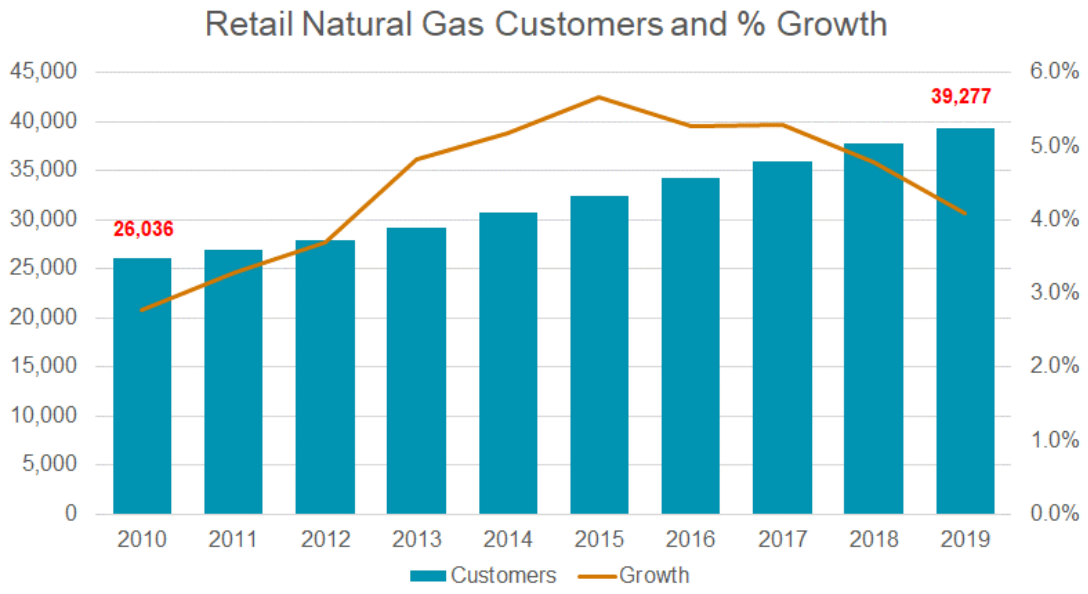
new customers as the communities of Fargo, West Fargo, and Horace grow in the future.

Q. PLEASE PROVIDE MORE INFORMATION ON THE COMPANY'S CURRENT GAS OPERATIONS AND GROWTH TRENDS IN THE FARGO/WEST FARGO AREA.

A. The Company currently serves almost 41,000 customers in Fargo/West Fargo and the surrounding area, which represents two-thirds of the Company's natural gas business in North Dakota. Additionally, some of our largest gas customers are located in the Fargo area. During 2019, at the time the Company was assessing the need for capacity expansion, the Company evaluated the historical growth trend over a ten-year period, which showed consistent and continuing growth in the area. Figure 3 below shows the Fargo/West Fargo area growth trend for 2010 through 2019.

Figure 3

Fargo/West Fargo Customer Growth Trend (2010-2019)



As shown, customer counts increased by more than 45 percent over this period. Further, from 2013 to 2019, there was continuing robust and sustained annual growth in the Fargo/West Fargo area. The historical growth rates for the Fargo area are higher than we experienced in other service territories across the NSP gas system, illustrating the strong economic development that has occurred and is forecasted to continue to occur in the Fargo area.

Q. PLEASE DESCRIBE THE COMPANY'S GAS SYSTEM MODELING AND EXPLAIN HOW THE CUSTOMER GROWTH RATES ARE FACTORED INTO THAT MODELING.

A. The Company utilizes industry standard hydraulic modeling software, called Synergi Gas, to model system capacity. The system capacity modeling methods are standardized across all service areas on the NSP gas system. Capacity models are updated annually with data relating to physical changes to the gas system, load growth projections, and operational conditions from SCADA to estimate and design for peak hour demand. The modeling also incorporates the Design Day temperature, reflecting the industry standard of a 1-in-30 year low temperature occurrence. Design Day temperatures were updated after the extreme cold weather event experienced in January 2019.

Q. CAN YOU DESCRIBE IN MORE DETAIL THE COMPANY'S EVALUATION OF GAS CAPACITY AFTER THE 2019 WINTER?

A. Yes. In January 2019, the region experienced severe cold weather over a sustained period that stressed the Company's ability to maintain reliable service for our firm natural gas customers. After reviewing the weather data from this cold weather event, Xcel Energy incorporated new Design Day temperatures into its gas capacity modeling throughout the NSP service

territory. Specifically, we modified our distribution system modeling with more severe temperature constraints to account for greater gas loads under the extreme cold conditions experienced in late January 2019. For the Fargo area, the peak design hour temperature was revised from the previous -35°F to -37°F.

Q. HOW WAS THE FARGO CAPACITY PROJECT IDENTIFIED AS A RESULT OF THIS MODELING?

A. After the cold weather in 2019, the Company completed updating its gas engineering models during fourth quarter 2019 with modifications for new peak hour design temperatures, gas system performance, and forecasted load growth. As we have updated our models over the last several years, and experienced strong customer growth in North Dakota, the Company had been forecasting additional capacity would be needed in the Fargo area in the coming years. However, based on the modeling and evaluation completed in 2019, the Company concluded that the project to add additional gas capacity to the Fargo area would need to be accelerated to 2021. The project was sized to meet current needs and future growth based on projected demand requirements of our firm customers. The Company's standard approach for capacity planning on this scale considers ten years of forecasted growth, which is factored into the design requirements.

B. Project Details

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE FARGO CAPACITY PROJECT?

A. Yes. The project will install approximately 25,500 feet of new 12-inch steel pipe to reinforce the Fargo/West Fargo gas distribution systems. The

proposed alignment currently impacts the rights-of-way along 9th Street East in West Fargo, and 55th Street South, Seter Parkway, and 33rd Avenue South in Fargo. The Fargo Capacity Project was designed to support projected growth in the area through 2029 and will serve the industry standard 1-in-30 design peak hour temperature at -37ºF. The total project capital additions reflected in the 2022 test year are approximately $27.5 million. The project is scheduled to be in service in the fall of 2021, thus operational during the winter of 2021-2022.

Q HOW DID THE COMPANY DETERMINE THE LOCATION FOR THIS CAPACITY EXPANSION PROJECT?

A. The Company considered five different projects to provide the necessary system capacity. While all options were designed to provide service for the same projected growth, the location selected was determined to be optimal based on cost and because it would avoid secondary upgrades to the system and other potential barriers to construction. I address the alternatives considered in the following section.

Q. DID THE COMPANY RECEIVE LOCAL PERMITS APPROVING THE FINAL PROJECT?

A. Yes. Since the project is not classified as a "transmission line" under North Dakota law and federal statutory definitions, the associated certification and siting permit were not required. However, the Company acquired the necessary land and received several local permits for the final project selected. Working with all impacted jurisdictional municipalities, the Company identified and submitted all required documentation for project approval and was in receipt of the following permits prior to work in the impacted permit area:

- Burlington Northern Sante Fe (BSNF) Railroad Crossing Permit;
- North Dakota I-94 Crossing Permit;
- City of Fargo Right-of-Way Permit;
- City of West Fargo Right-of-Way Permits (five in total); and
- State of North Dakota and the City of West Fargo required stormwater permits.

Additionally, a new permanent easement was procured for sections of the pipeline where necessary, and the remaining pipe will be installed in the utility easement.

Q. CAN YOU PROVIDE A SUMMARY OF THE TYPES OF WORK THAT WERE UNDERTAKEN TO COMPLETE THE PROJECT?

A. Yes. The project work includes project management, engineering, design, right-of-way acquisition, permitting, material procurement, and construction. At a high level, the construction work consists of pipe installation, using both open trench and boring methods as necessary, three below-grade bridal valve set installations, two above-grade launcher and receiver connections, full-line hydrostatic test, in-line inspection, final tie-ins with existing infrastructure, and commissioning activities. One new regulator station will be fabricated, installed, tested, and commissioned as well. Additionally, there are crews performing ancillary activities such as third-party inspection, control measure install, dewatering, handling of contaminated soils, non-destructive testing, line staking, survey, traffic control, and hard and soft surface restoration.

Q. CAN YOU PROVIDE DETAILS RELATED TO THE CONSTRUCTION SCHEDULE AND WORK COMPLETED TO DATE?

A. Yes. As of mid-July 2021, the project has installed approximately 15,000 feet of 12-inch steel pipe. The as-built survey, as well as hard and soft surface restoration, has kept pace with pipe installation. Additionally, all horizontal directional drilling has been completed, and the new regulator station has been fabricated. The remaining project work includes installation of approximately 10,000 feet of pipe and the associated as-built survey and restoration work, a limited amount of boring work, installation of the regulator station, and completion of valve configurations at tie-ins to existing infrastructure and the regulator station. Upon completion of this work, the line will be tested and commissioned, and temporary control measures will be removed. Table 2 below provides the primary project milestones and the expected project completion date.

Table 2

Fargo Capacity Project Timeline

Design Completed	April 9, 2020
Construction Started	May 3, 2021
In-Service Target	October 22, 2021

The project is expected to be in service in the fall of 2021, but there may be a small amount of restoration work necessary in the spring of 2022.

C. Project Benefits

Q. CAN YOU SUMMARIZE HOW THIS PROJECT BENEFITS NORTH DAKOTA CUSTOMERS?

A. Yes. First and foremost, the Fargo Capacity Project is needed to serve our

firm customers beginning in 2021, and given the strong growth in the largest metropolitan area in the state of North Dakota, is designed to meet customer need into the future. The new pipe will help maintain system reliability during extreme winter temperatures and will result in the ability to serve firm customers growth in the area for years to come. The proposed project is the most cost-effective way to address the growth and capacity need compared to the other viable alternatives. We have worked, and will continue to work, with city engineers to minimize the impact that project construction will have on the impacted communities.

Q. WILL THE FARGO CAPACITY PROJECT PROVIDE OTHER BENEFITS?

A. Yes. When completed, the project will be able to act as a "secondary" pipeline in the southwest part of the Fargo metro area, providing valuable redundancy in the area. This will allow for maintenance or emergency repairs to be accomplished with less disruption to customers. Second, a new southwest regulator station is being installed as part of this project that will provide consistent line pressure, resulting in better service for our customers and more efficient system operation. Additionally, construction of this line will facilitate further expansion of the system to the south and west, which have been identified as the primary future growth areas following the completion of the Red River Diversion Project. I also note that in terms of jobs, we have upwards of a hundred workers contracted and engaged in the construction of the project as described in the preceding section.

D. Project Alternatives

Q. DID THE COMPANY ASSESS ALTERNATIVES TO THIS CAPACITY EXPANSION PROJECT?

A. Yes. While it was clear from the system modeling results that a capacity expansion would be needed to serve firm customer growth in the Fargo area, there were several options for how this capacity could be added to the system. The Company assessed five different projects in total, each designed to provide the additional needed capacity. The Company then assessed each project based on 1) cost, 2) whether upgrades to other infrastructure would be needed (such as a town border station where the Company receives gas from the transmission pipeline system), and 3) other potential construction conflicts.

Q. CAN YOU SUMMARIZE THE RESULTS OF THE COMPANY'S EVALUATION OF THE FARGO CAPACITY PROJECT ALTERNATIVES?

A. Yes. Table 3 below provides the results of the evaluation, comparing the alternatives based on the considerations identified above. As shown, the Fargo Capacity Project was the preferred approach, based mainly on its lower costs and because it did not require additional construction on the system or pose any potential barriers to completing construction in the necessary timeframe.

Table 3

Summary of Fargo Capacity Project Alternatives

Project	Cost	Pipeline Diameter (inches)	Pipeline Length (feet)	Provided Growth To 2029	Provides Some Form Of System Redundancy	Requires Rebuild Of WBI Town Border Station	Possible Construction Moratorium On 45th Street South	Possible Impact with Flood Diversion Project	Construction Timeline Greater Than One Year
Fargo HP System Extension	$28M	12	24,000	X	X				
Alternative #1	$32M	16	23,800	X		X			
Alternative #2	$29M	12	25,000	X		X			
Alternative #3	$28M	12	25,000	X	X		X		
Alternative #4	$56M	12	48,000	X	X			X	X

Q. PLEASE EXPLAIN MORE SPECIFICALLY WHY THE COMPANY DID NOT CHOOSE ALTERNATIVE NOS. 2 OR 3, GIVEN ROUGHLY THE SAME COST ESTIMATES.

A. Alternative 2 consisted of replacing the existing 6-inch and 8-inch Fargo TBS pipeline with 12-inch steel pipe. Drawbacks of proceeding with this project included that it may have required a rebuild of the Mapleton town border station (at an additional cost of approximately $1.5 million), and there was uncertainty around whether WBI could deliver the increased supply. Further, replacement of existing pipeline would not provide the system redundancy and associated benefits that the selected project provides, as described above. Alternative 3 consisted of reinforcing the 45th Street South 6-inch pipeline with parallel 12-inch steel pipe. Drawbacks of this project included consideration of a Fargo construction moratorium (due to recent roadway upgrades) that may have affected route viability.

Q. PLEASE SUMMARIZE WHY THE COMPANY'S INVESTMENT IN THE FARGO CAPACITY PROJECT WAS PRUDENT AND REASONABLE FOR NORTH DAKOTA CUSTOMERS.

A. The Fargo Capacity Project is needed to expand natural gas service in the Fargo/West Fargo area in response to firm customer growth and meeting the capacity need identified in 2021. The project will allow the Company to continue to serve existing and new firm customers into the future and will improve reliability and enhance system resiliency during cold weather events. Among the alternatives considered, the project was selected because it was the lowest-cost alternative, did not require secondary upgrades to the system, and there were no known barriers or potential construction conflicts that would impact the completion date. For these reasons, the Fargo Capacity Project is a prudent investment to serve our North Dakota customers.

IV. PEAKING PLANT INVESTMENTS

Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE OPERATION OF THE COMPANY'S PEAKING PLANTS?

A. Yes. As I mentioned, the Company has three gas peaking plants: the Wescott LNG peaking plant, the Sibley Propane Air facility, and the Maplewood Propane Air facility.

The largest of the Company's three gas utility peaking plants is the Wescott LNG Peaking Plant, located in Inver Grove Heights, MN. The Wescott peaking plant can store approximately 2,145,000 Dth of LNG in two storage tanks. Essentially, the Company purchases natural gas to store at Wescott during the non-heating season when gas is readily available and typically priced more favorably. Throughout the spring and fall "shoulder" months, the Company liquefies purchased natural gas in a process that reduces its temperature to approximately -260ºF. The natural gas is then stored in a liquefied state. Early in the winter, the Wescott plant "turns over" to prepare for and implement the vaporization process whereby the liquefied natural gas is vaporized and injected back into the system. The vaporization process heats the pressurized natural gas back up to a temperature where it returns to its gaseous state. Because Wescott cannot readily switch from liquefaction to vaporization, the amount of natural gas in storage at the beginning of the heating season is the maximum the Company will have in LNG storage for the heating season.

The Company's other two peaking facilities store propane: the Sibley Propane Air Peaking Plant in Mendota, MN and the Maplewood Propane

Air Peaking Plant in Maplewood, MN. The Sibley facility can store approximately 114,000 Dth equivalent of propane, with a technical maximum single-day withdrawal capacity is 46,000 Dth. The Maplewood plant can store approximately 124,000 Dth equivalent of propane, with a technical maximum single-day withdrawal capacity of 44,000 Dth. Once propane is mixed with air, it can be injected into the natural gas system.

Because these plants generally are available to provide gas to firm customers during peak conditions, the Company is able to avoid acquiring incremental pipeline capacity to meet the same need, and use of these facilities provides for additional gas supply options as we serve our North Dakota customers during extreme weather conditions.

Q. WHAT TYPES OF INVESTMENTS IN THE PEAKING PLANTS ARE NEEDED FROM TIME TO TIME?

A. Capital projects that support our peaking plants include investments to enhance reliability and maintain compliance with state and federal codes. Investments may be related to routine plant maintenance or discrete projects necessary to maintain operational reliability and compliance with state and federal codes.

Q. HAS THE COMPANY MADE CAPITAL INVESTMENTS IN THESE PLANTS SINCE THE 2007 RATE CASE?

A. Yes. In 2013, we replaced the liquefaction compressor at the Wescott LNG plant, as the engine had reached the end of its useful life. The compressor is the main component of the liquefaction process. This project increased the reliability of the plant and reduced operating costs by increasing energy

efficiency. In 2016, a new air compressor system was installed at the Sibley peaking plant. The project replaced compressors and corresponding equipment that impact the process of mixing the propane with air before it is injected into the system, and also improved the reliability of the plant. These two projects resulted in capital additions totaling $2.9 million for the North Dakota jurisdiction.

Q. WHAT ARE THE GAS OPS PLANT INVESTMENTS AFFECTING THIS RATE CASE?

A. As described by Company witness Mr. Greg P. Chamberlain, the Company's peaking plant investments are a driver of the case. These investments include significant refurbishment and replacement of the existing infrastructure in all three facilities to prepare them for continued operation for many years to come. The largest investments in the Wescott, Maplewood, and Sibley plants are occurring in the 2021-2022 timeframe.

Q. HOW DID THE COMPANY DETERMINE THE NEED FOR THE PLANT INVESTMENTS IN 2021 AND 2022?

A. The Company first identified the investments needed during plant evaluations in November and December of 2020, while testing certain components of the equipment in preparation for winter operations. Evaluations continued into early 2021. During these reviews, the Company identified the necessary refurbishment and upgrades, due primarily to the condition of some of the systems. Some of these upgrades will need to be completed before plant operations can recommence. The Company expects the necessary projects to be completed and the plants to return to service during the 2021-2022 heating season.

Q. WHAT INVESTMENTS ARE NEEDED AT THE WESCOTT PLANT?

A. The Company will (1) install variable two frequency drive units on the LNG pumps to limit their output; (2) route and manifold all thermal relief valves on the vaporization system to a knockout drum and vent stack with new root valves and test points, thereby enabling maintenance and testing; 3) install a new full-sized process relief to limit overpressure and replace control and manual isolation valves to allow for safe sectionalizing of the system; 4) install fire protection upgrades to increase reliability; and 5) replace obsolete software and hardware to provide real time data to the plant control center for flow path operations and system control.

Q. WHAT INVESTMENTS ARE NEEDED AT THE SIBLEY AND MAPLEWOOD PLANTS?

A. Projects planned and underway for Sibley include vaporizer system upgrades such as a new vaporizer, super heater, pre-heater, mixing system, and all associated piping and valving within the existing vaporizer building. Replacement of boiler feedwater pumps and installation of new wiring will also be part of the project. The Company will primarily replace aging equipment including valves, vaporizers, and the boiler systems, as well as associated piping.

At Maplewood, the systems to be upgraded are the vaporizer system, pad gas, plant air, boiler systems and SCADA control systems. The projects include a new vaporizer, super heater, pre-heater, mixing system, and replacement of piping and valving within the existing vaporizer building. In addition, the Company will implement new piping from the pumps to the vaporizer building and modifications to the plant air piping, and add a plant air dryer with new steam piping boiler feedwater pumps and instrumentation and wiring.

At both plants, the Company will also make modifications to the electronic controls systems for the equipment. Additionally, the Company will make improvements to safety systems, such as installation of additional gas detection equipment.

Q. WHAT ARE THE ALTERNATIVES TO MAKING THESE PEAKING PLANT INVESTMENTS?

A. The only reasonable alternative to investing in the gas plants is to acquire an additional 246,000 Dth of firm capacity on Northern Natural Gas (Northern) pipeline. However, Northern would need to construct substantial facilities over a three-year period to make the capacity available. The Company estimates that it would have to pay an additional $60 - $70 million per year in pipeline demand charges for the new capacity. Given the extended delay in service and the large costs involved, Northern construction is not a reasonable alternative.

Q. HOW DO THESE PLANT INVESTMENTS BENEFIT NORTH DAKOTA CUSTOMERS?

A. These plants help ensure safe and reliable service to North Dakota customers and the entire gas system, as discussed in Section II of my testimony, particularly during peak capacity periods. The Company's planned investments are likewise necessary to ensure the continuing safe and reliable operation of these facilities. As a result, it is reasonable for North Dakota customers to bear a portion of costs necessary to maintain operational reliability of the plants and compliance with state and federal codes. Mr. Halama discusses the allocation of gas system costs in his Direct Testimony.

V. GAS OPERATIONS O&M EXPENDITURES

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

A. I provide an overview of the types of operations and maintenance (O&M) expenses for Gas Ops. I also present 2007-2022 O&M expenditures for Gas Ops including key drivers and trends.

A. Types of Gas Ops O&M Expenses

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

A. Gas Ops incurs O&M expenses across various areas that are related to numerous activities to support the gas system. Federal and state codes also require robust inspection and maintenance programs for gas utilities, the majority of which result in O&M expenditures. Further, integrity management programs at times add O&M costs to mitigate system risks. Examples include ongoing health and condition assessments for gas pipelines, as well as accelerated leak surveys for known problematic distribution pipe types under renewal programs. We also must perform emergency response and requested underground locates. Other types of O&M expenses include both internal and contract labor, materials, transportation, and other expenses such as facilities costs and licensing fees. These O&M costs are related to the day-to-day operations of our gas distribution system as we continue to provide safe, reliable service to our customers.

Q. HOW ARE GAS OPS O&M EXPENDITURES ALLOCATED?

A. Similar to capital additions, Gas Ops O&M expenses are direct assigned to the North Dakota jurisdiction to the extent they are solely serving that jurisdiction. For example, damage prevention costs are direct assigned to the

area where the work is completed. Accordingly, damage prevention costs in Fargo are assigned fully to the North Dakota jurisdiction. That said, certain Gas Ops 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 the allocation methodology discussed by Mr. Halama.

B. Gas Ops O&M 2007-2022

Q. WHAT HAS BEEN THE GAS OPS' O&M SPENDING SINCE THE COMPANY'S LAST NORTH DAKOTA RATE CASE?

A. Table 4 below shows the North Dakota Distribution O&M expense level approved in the Company's last rate case for 2007, actual expenditures through 2020, and the forecasted O&M expenses for 2021 and the 2022 test year.

Table 4

Gas Operations Distribution O&M 2007-2022

State of ND Gas Jurisdiction

2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
$2.2	$3.0	$3.5	$3.5	$3.3	$3.2	$3.7	$4.1	$4.9	$5.1	$4.3	$4.4	$6.0	$5.3	$5.2	$5.1

Q. WHAT DOES TABLE 4 INDICATE REGARDING GAS OPS DISTRIBUTION O&M EXPENSES OVER TIME?

A. Table 4 illustrates since our last rate case that Gas Ops O&M expense has increased on an overall basis. Distribution costs in 2022 are approximately $2.9 million higher than the 2007 test year in our last rate case, an average

increase of approximately six percent per year. This is due in large part to customer growth over the same period, as well as inflation, with the increases partially offset by ongoing efficiency efforts.

However, I note that Company O&M has been generally flat since 2015, with some limited variability, due to the Company's ongoing efforts to increase efficiency, contain O&M expenditures, and deploy cost reductions for customers' benefit. These efforts offset cost increases due to inflation and in other areas such as Damage Prevention.

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

A. The Damage Prevention program helps excavators and customers locate underground gas infrastructure to avoid accidental damage and safety incidents. NSP relies on a combination of internal labor and contractors for the Company's Damage Prevention program. The primary purpose of this program is to reduce damage to Company-owned buried facilities caused by excavation. Excavation-related damage has the potential to impact public safety and service reliability. This requirement is further supplemented by state law in North Dakota. This program has been designed to ensure compliance with state and federal regulations, and NSP relies heavily on contractors to perform this work.

Q. WHY HAVE DAMAGE PREVENTION COSTS INCREASED?

A. North Dakota damage prevention costs increased by $400,000 between 2019 and 2020 actuals and are further forecasted to increase by $100,000 between 2020 and 2021. These increases are attributable to both an increase in the volume of underground locate requests and a higher contract cost per locate

due to contractor cost increases. The Company relies on a combination of internal labor and contractors for the Company's Damage Prevention program, with contractors helping to cover high demand for locate requests during the construction season. Further, damages caused by vendors mislocating our underground facilities are covered by the vendor, which reduces risk to the Company and our customers. We are forecasting a further cost increase for 2021 because our vendor contracts expired and needed to be renegotiated.

Q. WHY WAS THERE A COST INCREASE IN THE NEW CONTRACT THAT WENT INTO EFFECT FEBRUARY 1, 2020?

A. 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. Damages caused by vendors mislocating our underground facility are covered by the vendor, which is a major factor in our decision to utilize outside vendors for this type of work.

Q. YOU NOTED EARLIER THAT O&M COSTS HAVE REMAINED LARGELY FLAT SINCE 2015. CAN YOU EXPAND ON THE REASON FOR THIS TREND?

A. Yes. In addition to the ongoing efforts to increase efficiency and contain O&M expenditures despite rising costs, O&M costs declined in 2020 due to a shift from O&M to capital work, resulting in a reduction in O&M. 2020 O&M also declined due to impacts of the COVID-19 pandemic, such as reductions in employee travel and participation in elective training opportunities. The additional O&M reduction in 2022 can be attributed to the Company's Fargo Capacity Project, which results in increased capacity and reduced O&M

expenses because onsite CNG storage trailer rentals are no longer needed to support local capacity needs. Overall, while O&M is currently higher than it was at the time of our last rate case with a 2007 test year, O&M for the 2022 test year is projected to be flat compared to 2015 and 2016 despite inflation, and lower than in more recent years.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the 2022 test year revenue requirement increases attributable to the Gas Ops system investments and O&M expenditures, as supported by the information provided in my testimony. The Company has made significant capital additions to its gas distribution system since its last natural gas rate case. These investments have been driven by strong customer growth in our North Dakota service territory, as well as our ongoing work to enhance the safety and reliability of the service we provide to our North Dakota customers. In particular, our investments in the Fargo Capacity Project and in our gas peaking plants will help meet the natural gas demand needs and provide benefits for our North Dakota customers into the future.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications
Joni H. Zich

I received a Bachelor of Business Administration degree in Management Information Systems from the University of Wisconsin – Eau Claire in 1987. I received a Master of Business Administration from the University of Wisconsin – Eau Claire in 2000. I was hired by Northern States Power Company – Wisconsin (NSPW) as an Information Specialist in the Marketing Department in 1988, progressing to an Analyst during my tenure in the Department. My experience in Marketing included the development of demand side management programs.

In 1994, I transferred to the Gas Supply and Planning department, where I was responsible for scheduling gas on several interstate pipelines to ensure system load requirements were balanced. After 15 months, I was promoted to a trading position where I was responsible for the purchase and sale of natural gas supply for NSPW including the acquisition of physical supply agreements and the use of financial derivatives. I later managed the gas purchasing and sales activities, transportation scheduling, accounting operations, and NSPW's non-traditional wholesale gas sales programs.

In 1999, I transferred to Gas Resource Planning. In this role I was responsible for the development and implementation of dynamic strategic system planning for NSPW, Northern States Power – Minnesota (NSPM), and Northern States Power

Company's gas fired generation for their respective upstream gas transportation and storage assets, ensuring reliable and cost effective delivery. As the Manager of Gas Resource Planning, I managed several regulatory proceedings regarding the cost recovery of upstream gas assets where I testified before several state regulatory commissions and at the Federal Energy Regulatory Commission (FERC).

In April 2012, I was promoted to Director of System Strategy and Business Operations for Xcel Energy Services Inc. (XES) the "service company" subsidiary of Xcel Energy, Inc. (Xcel Energy), a registered holding company. In this capacity, I am responsible for the long-term gas capacity planning for the Company's high-pressure and intermediate-pressure gas system, the overall financial governance of the gas operations including capital investments, management and administration of integrity management riders (including the PSIA), and the development of gas emission reduction strategies. In addition, I direct the Natural Gas Services team, which manages all aspects of Public Service's gas transportation services. In addition to these responsibilities, in January 2021, I also began directing the Company's gas governance organization, which includes gas standards, compliance, contractor inspections, quality assurance, and the Pipeline Safety Management System (PSMS) when I was promoted to Senior Director, Strategy, Governance and Strategy.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company for Authority To Increase Rates for Natural Gas Service In North Dakota	))))	Case No. PU-21-___

AFFIDAVIT OF
Joni H. Zich

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.

Joni H. Zich

Subscribed and sworn to before me, this 19 day of August, 2021.

Notary Public Wisconsin
My Commission Expires: 4/15/2024
County of Sawyer
State of Wisconsin.

PETER ANDERSON NOTARY PUBLIC STATE OF WISCONSIN