



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

Statement of Qualifications

Schedule 1

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

3
4 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

5 A. The purpose of my Direct Testimony is to support the revenue requirement
6 increases attributable to the Gas Operations (Gas Ops) system investments
7 and O&M expenditures that are driving the need for this rate case.¹ The
8 Company has made significant capital additions to its gas distribution system
9 since its last natural gas rate case, which was filed 15 years ago (Case No. PU-
10 06-525 using a 2007 test year) (2007 Rate Case). I discuss how these
11 investments have been driven by strong customer growth in our North
12 Dakota service territory, as well as our ongoing work to enhance the safety and
13 reliability of the service we provide to our North Dakota customers.

14
15 In particular, I provide support for the Company's Fargo/West Fargo capacity
16 expansion project (Fargo Capacity Project) to meet the natural gas demand
17 needs of North Dakota customers into the future. I also support our current
18 investments in the Company's gas peaking plants, as well as our ongoing
19 investments to support new business, safety, system reliability, and mandated
20 relocations. Finally, I also address changes in Gas Ops O&M costs since the
21 2007 Rate Case.

22
23 Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

24 A. My testimony is organized into the following sections:

- 25 • *Section I* – Introduction
26 • *Section II* – Gas Utility Overview

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

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

5
6

II. GAS UTILITY OVERVIEW

7
8

A. North Dakota Gas Operations

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

11 A. NSP provides natural gas sales and transportation service to approximately
12 60,000 residential, commercial, and industrial customers in North Dakota in
13 the cities of Fargo, West Fargo, Grand Forks, and several surrounding
14 communities. We operate distribution facilities to serve our North Dakota
15 customers in three counties within the state. This includes approximately
16 1,100 miles of distribution mains and over 60,000 meters, as well as regulator
17 stations and other supporting infrastructure. The Company provides natural
18 gas utility services in North Dakota as part of the NSP gas system, operated
19 as an integrated retail natural gas procurement and delivery system that serves
20 the Company's gas customers in portions of both North Dakota and
21 Minnesota.

22

23 Q. WHAT ARE THE PRIMARY GAS OPS FUNCTIONS?

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

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

5
6 Q. WHAT ARE SOME OF THE SIGNIFICANT CHANGES TO THE COMPANY'S GAS
7 SYSTEM AND BUSINESS SINCE THE 2007 RATE CASE?

8 A. First, while the Company has continued to serve the same North Dakota
9 communities as in the past, the size of our business and natural gas system in
10 North Dakota has grown over this time. The number of retail customers we
11 serve in North Dakota has increased by approximately 40 percent, from
12 43,000 as of our 2007 Rate Case to 60,000 currently. As a result, between
13 2007 and 2020, the Company added 16,075 new gas services and
14 approximately 267 miles of new distribution main in North Dakota. Further,
15 the local growth in the Fargo/West Fargo area was the primary driver of the
16 need for the Fargo Capacity Project detailed in Section III below. Customer
17 growth has also resulted in additional work as we have responded to increasing
18 customer underground locate requests and gas emergency calls.

19
20 At the same time, we have enhanced the safety and reliability of the service we
21 provide to our North Dakota customers. While we continue to invest in routine
22 system maintenance and respond to customer growth needs, we have also
23 enhanced system integrity with capital investments to help ensure public safety,
24 consistent with evolution of the industry and federal and state regulations that
25 have emerged during the past 15 years.

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

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

11
12 Subsequently, the Pipeline Safety, Regulatory Certainty, and Job Creation Act
13 of 2011² (2011 Pipeline Safety Act) was signed into law on January 3, 2012,
14 leading to additional requirements and development of further industry
15 practices to protect the safety and integrity of natural gas infrastructure. These
16 requirements call upon gas utilities to make investments to replace aging
17 materials and historical construction practices through main and service
18 renewals, as well as data gathering and management that did not previously
19 exist for aging infrastructure. During this same timeframe, in 2012, the
20 Company established a separate gas business unit, resulting in an increased
21 focus on public safety and enhanced expectations for its gas distribution and
22 transmission systems.

23

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

² <https://www.govinfo.gov/content/pkg/PLAW-112publ90/pdf/PLAW-112publ90.pdf>

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

8
9 **B. The NSP Gas System**

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

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

20
21 Q. HOW DOES NSP PROCURE NATURAL GAS TO SERVE ITS CUSTOMERS IN NORTH
22 DAKOTA?

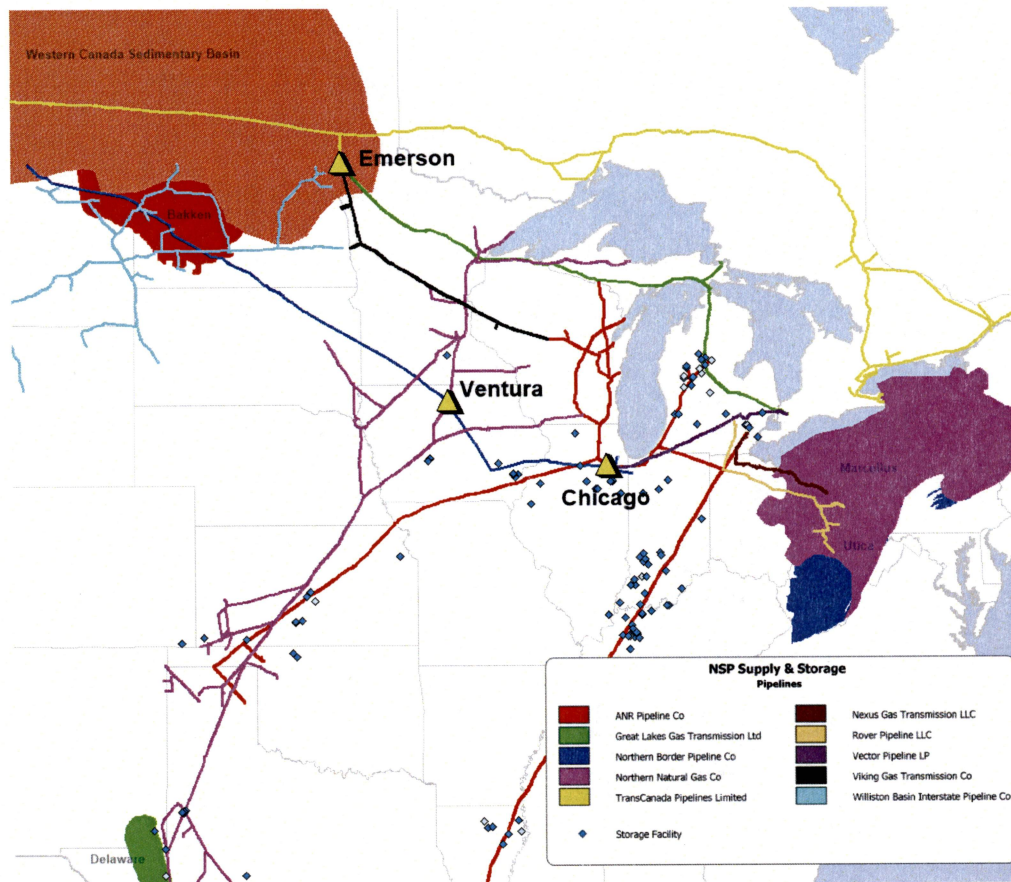
23 A. As noted above, the overall gas system allows for unified purchasing and
24 transportation of natural gas for NSP gas customers, including those in North
25 Dakota. This enables efficient natural gas acquisition and delivery functions,
26 which lowers costs for all of our natural gas retail customers.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

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

3

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

1
2
3 **Figure 1**
4 **NSP Supply and Storage**



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

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

1 is not of sufficient size to serve North Dakota customers in its own right.
2 Therefore, the integrated system also utilizes transportation services on several
3 other interstate pipelines, as shown in Figure 1. For example, the Company
4 uses upstream transportation and underground storage services on several
5 interstate gas pipelines that connect to Viking to serve its North Dakota
6 customers, including those owned by Northern Natural Gas Company, ANR
7 Pipeline Company, Great Lakes Gas Transportation Limited, and Northern
8 Border (as discussed above).
9

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

12 A. Yes, the Company also incorporates use of underground storage services
13 available on several interstate pipelines, as well as the Company's peaking
14 plants, which provide additional capacity for the gas system.
15

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

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

1 Q. PLEASE DESCRIBE THE COMPANY'S PEAKING PLANTS.

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

14
15 Q. HOW DOES OPERATION OF THE BROADER NSP GAS SYSTEM BENEFIT THE
16 COMPANY'S NORTH DAKOTA CUSTOMERS?

17 A. The diversity of market centers, access to multiple supply points and storage
18 facilities, and the peaking plants provided by the overall NSP gas system
19 deliver value for our North Dakota customers that would be unavailable if
20 served by a separate, stand-alone gas system. Both the size of the NSP gas
21 system, serving approximately 530,000 customers (of which 60,000 are located
22 in North Dakota), and the geographic area covered contribute to these
23 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.

1 Q. PLEASE EXPLAIN FURTHER.

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

14

15 **C. Overview of Capital Investments**

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

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

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

3
4 Q. CAN YOU PROVIDE ADDITIONAL INFORMATION REGARDING THE TYPES OF
5 GAS OPS CAPITAL INVESTMENTS?

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

8
9 **Safety:** Maintaining safety requires a multi-faceted work and capital
10 investment approach that takes into account the complex nature of the
11 system, the multiple risks that face any natural gas system, and the
12 requirements of the United States Department of Transportation's Pipeline
13 and Hazardous Materials Safety Administration. Much of the Company's
14 safety work is focused on maintaining the integrity of its gas system assets.
15 This also includes work on our infrastructure to reduce leaks, improve public
16 safety (such as our program to move meters that are inside customer premises
17 to an outside location), and renew service mains and pipes.

18
19 **Reliability:** Maintaining a reliable system requires identification of capacity
20 needs to serve firm customers on a peak design hour. The peak design hour
21 reflects temperature extremes of -37°F for Fargo and -40°F for Grand Forks.
22 Reliability initiatives include larger pipeline capacity-building investments like
23 the Fargo Capacity Project or smaller routine asset health and capacity
24 investments.

25
26 **New Customer Business:** The Company has the obligation to serve new
27 customers that request gas service within its service territory under its tariff

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

5
6 **Mandatory Relocations:** The Company is required to move existing
7 infrastructure to meet federal, state, and/or local requirements. This includes
8 relocating facilities required by a governing authority or that are in direct
9 conflict with street expansions within public rights-of-way. The Company
10 must invest capital to achieve these relocations and re-establish service via
11 infrastructure at a different location.

12
13 **Peaking Plants:** The Company has three gas peaking plants – one LNG
14 plant, (Wescott), and two propane plants (Sibley and Maplewood). These
15 plants help ensure that the Company has adequate capacity to serve firm
16 customers during periods of cold weather or during other operational or
17 market issues. These plants are discussed in Section II above and in further
18 detail in Section IV below.

19
20 Q. PLEASE PROVIDE AN OVERVIEW OF THE GAS OPS CAPITAL ADDITIONS FROM
21 2007 TO 2022.

22 A. Table 1 below reflects the Gas Ops capital additions (i.e., infrastructure placed
23 in service) from 2007 through 2020, and the forecasted capital additions for
24 2021 and the 2022 test year. This information is shown in categories for which
25 we can provide comparative data over this extended period.

1 **Table 1**

2 **2007-2022 Gas Capital Additions (Millions)**

3 **State of North Dakota (includes AFUDC)**

4

	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

5

6

7

8

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

10 TIME?

11 A. Overall, capital investments have increased over the past 15 years due

12 primarily to customer growth, with some variance on a year-to-year basis

13 depending on the specific work that is necessary to meet the gas requirements

14 of our customers and ensure the safety of our customers and employees.

15 Much of the work is routine distribution system work, consisting primarily of

16 many smaller investments in new or renewed gas services and mains, with

17 other work consisting of larger discrete projects. For example, looking

18 backward, in 2013 and 2016 we made some larger investments in our peaking

19 plants, as I describe in Section IV of my Direct Testimony, in addition to

20 investments related to customer growth. Customer growth has continued

21 and, beginning in 2018 and 2019 through the present, we specifically increased

22 investment in North Dakota to help ensure continuing system reliability.

23

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

25 TIME?

26 A. Yes. While the Company's gas system in North Dakota has performed very

27 well over time, beginning in 2018, we began increasing distribution system

1 investments in North Dakota to help ensure continuing service, safety, and
2 reliability. A key driver of these investments was new customer growth. In
3 2018, for example, routine new business activity relating to installation of new
4 mains, services, and meters accounted for \$4.8 million of the \$8.2 million total
5 distribution investment. More recently, we have also been working on larger
6 projects and programmatic work to meet more recent system and customer
7 needs, particularly by way of the non-recurring Fargo Capacity Project (which
8 accounts for \$27.5 million of the \$36.7 million in capital additions in 2021 and
9 is described in Section III of my Direct Testimony), and refurbishing the
10 Company's peaking facilities (described in Section IV of my Direct
11 Testimony). In 2022 and beyond, after completion of the Fargo Capacity and
12 peaking facility projects, we are initiating or ramping up programmatic system
13 safety and reliability work to serve North Dakota customers, including our
14 multi-year Inside Meter Move Out, DIMP, and meter Module Replacement
15 programs.

16
17 Q. WHAT ADDITIONAL SAFETY WORK IS THE COMPANY PLANNING FOR 2022?

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

22
23 Q. WHAT ARE THE COMPANY'S PLANNED DISTRIBUTION INTEGRITY
24 MANAGEMENT PROGRAM INVESTMENTS?

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

1 is targeted towards removing identified higher-risk gas infrastructure materials
2 (e.g., bare steel or vintage plastic) and replacing them with modern materials.
3 As we complete other discrete projects in 2021, we are increasing this work in
4 2022 and beyond, and plan to replace approximately six miles of poor
5 performing main and 600 services annually.
6

7 Q. WHAT IS THE INSIDE METER MOVE OUT PROGRAM?

8 A. The Inside Meter Move Out program will move most of our gas meters still
9 located inside of customer premises to outside locations, and replace the
10 existing facilities with new meters, connections, and regulators. The relocation
11 of meters outside of a customer's premise ensures accessibility to meters as
12 required by federal code and allows the Company to more efficiently perform
13 routine required inspection and maintenance of these meters without having
14 to coordinate access or inconvenience the customer. Additionally, moving the
15 meters to outside locations where possible reduces the risk of gas
16 accumulating in a confined space, where there are more sources of ignition.
17 We have determined that there are over 550 meters located inside customers'
18 premises in the state of North Dakota that can be moved outside. This
19 program will move these meters to outside locations over a period of five
20 years, beginning with approximately 100 meters in 2022.
21

22 Q. WHAT ADDITIONAL RELIABILITY WORK IS THE COMPANY UNDERTAKING?

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

1 Q. WHAT IS THE MODULE REPLACEMENT PROGRAM?

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

12

13 Q. PLEASE SUMMARIZE NEW BUSINESS PROJECT INVESTMENTS.

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

24

25 Q. PLEASE SUMMARIZE MANDATORY RELOCATION INVESTMENTS.

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

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

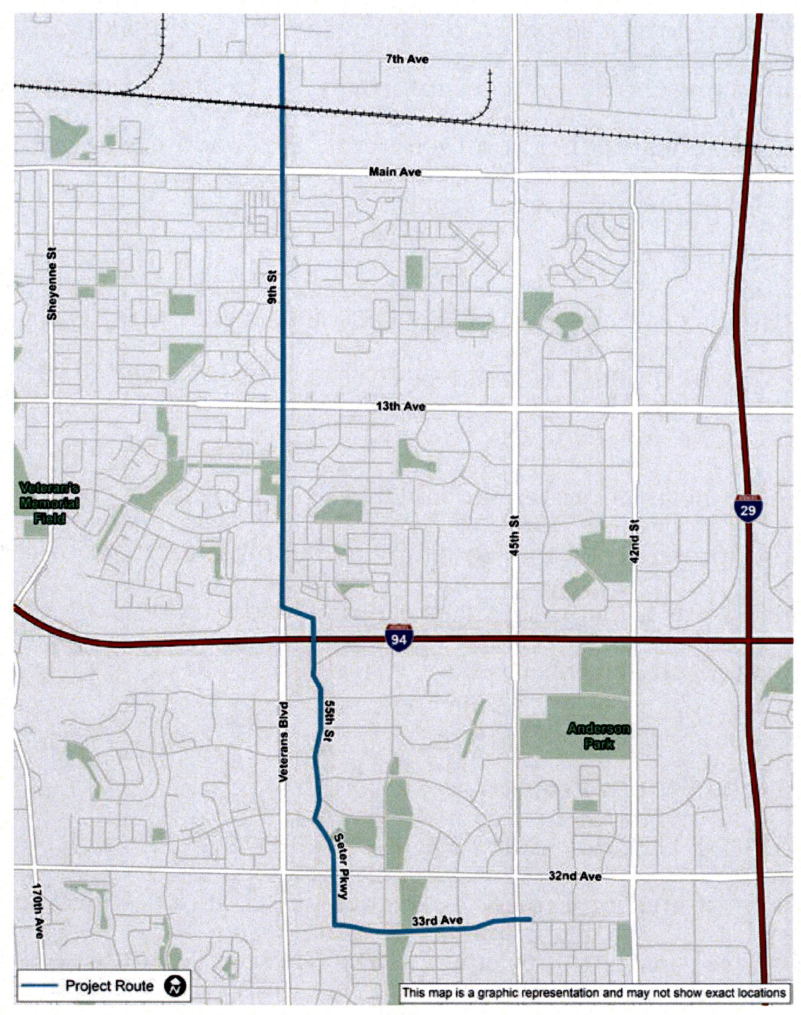
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9 **III. FARGO CAPACITY PROJECT**

10
11 Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENT IN THE FARGO CAPACITY
12 PROJECT.

13 A. The Fargo Capacity Project will increase natural gas distribution capacity
14 within the Fargo, West Fargo, and Horace service areas to continue to meet
15 customer growth in the area. The Fargo Capacity Project will allow the
16 Company to continue to serve existing and forecasted new customers and will
17 improve reliability and system resiliency during extreme cold weather. The
18 project consists of constructing a 12-inch pipeline approximately 4.5 miles
19 long running along 9th Street in West Fargo, under Interstate 94, and along
20 55th Street South, Seter Parkway, and 33rd Avenue in Fargo. A map showing
21 the location of the Fargo Capacity Project is provided in Figure 2 below.
22 Construction began in May of 2021, and the project is expected to be in-
23 service in November 2021.

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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

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

7
8 Q. HAS THE PROJECT SCOPE OR COST ESTIMATE CHANGED SINCE THE
9 COMPANY’S OCTOBER 2020 PRESENTATION OR JANUARY 2021 FILING WITH
10 THE COMMISSION?

11 A. There have been no material changes to the project or construction timing
12 previously provided by the Company. The initial estimate of approximately
13 \$28 million was a planning phase estimate and is consistent with the capital
14 additions reflected in this case.

15
16 **A. Need for the Project**

17 Q. WHY IS THE FARGO CAPACITY PROJECT NEEDED?

18 A. The Fargo Capacity Project is needed to continue to reliably serve the
19 Fargo/West Fargo area now and into the foreseeable future. In light of strong
20 customer growth in the area, the existing system is nearing its full capacity and
21 further expansion is necessary. The inadequacy of the current local
22 distribution system has already been evidenced by our need to employ
23 compressed natural gas (CNG) trailers in the Fargo area during the winter of
24 2020/2021 to maintain adequate system pressures for existing firm customers
25 on the coldest of days. The Fargo Capacity Project will help ensure reliable
26 service to existing firm customers during cold winter weather, reduce O&M
27 costs associated with the CNG trailers, and provide the capacity for service to

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

3

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

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

14

15

Figure 3

16

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

17

Retail Natural Gas Customers and % Growth

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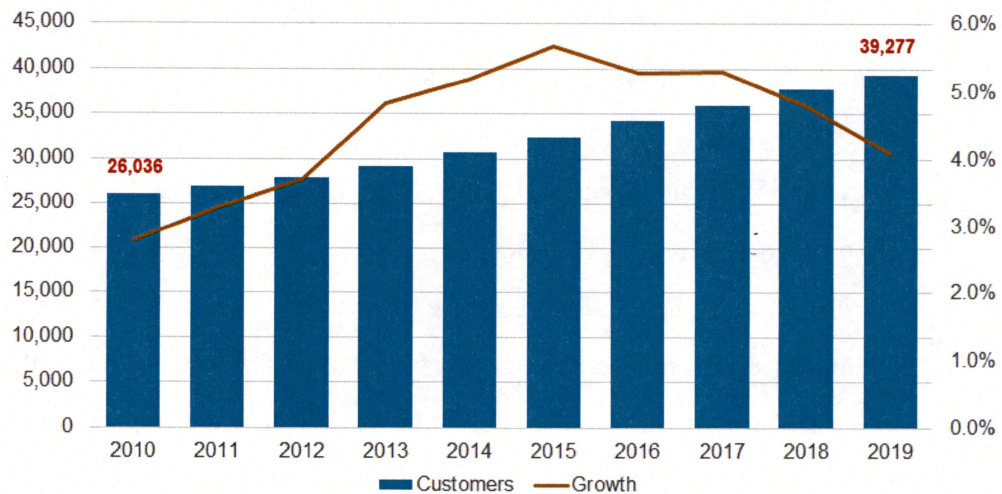
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1 As shown, customer counts increased by more than 45 percent over this
2 period. Further, from 2013 to 2019, there was continuing robust and
3 sustained annual growth in the Fargo/West Fargo area. The historical growth
4 rates for the Fargo area are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

8
9 Q. PLEASE DESCRIBE THE COMPANY'S GAS SYSTEM MODELING AND EXPLAIN
10 HOW THE CUSTOMER GROWTH RATES ARE FACTORED INTO THAT MODELING.

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

20
21 Q. CAN YOU DESCRIBE IN MORE DETAIL THE COMPANY'S EVALUATION OF GAS
22 CAPACITY AFTER THE 2019 WINTER?

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

1 territory. Specifically, we modified our distribution system modeling with
2 more severe temperature constraints to account for greater gas loads under the
3 extreme cold conditions experienced in late January 2019. For the Fargo area,
4 the peak design hour temperature was revised from the previous -35°F to
5 -37°F.

6

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

9 A. After the cold weather in 2019, the Company completed updating its gas
10 engineering models during fourth quarter 2019 with modifications for new
11 peak hour design temperatures, gas system performance, and forecasted load
12 growth. As we have updated our models over the last several years, and
13 experienced strong customer growth in North Dakota, the Company had been
14 forecasting additional capacity would be needed in the Fargo area in the
15 coming years. However, based on the modeling and evaluation completed in
16 2019, the Company concluded that the project to add additional gas capacity
17 to the Fargo area would need to be accelerated to 2021. The project was sized
18 to meet current needs and future growth based on projected demand
19 requirements of our firm customers. The Company's standard approach for
20 capacity planning on this scale considers ten years of forecasted growth, which
21 is factored into the design requirements.

22

23 **B. Project Details**

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

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

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

9
10 Q HOW DID THE COMPANY DETERMINE THE LOCATION FOR THIS CAPACITY
11 EXPANSION PROJECT?

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

18
19 Q. DID THE COMPANY RECEIVE LOCAL PERMITS APPROVING THE FINAL PROJECT?

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

- 1 • Burlington Northern Sante Fe (BSNF) Railroad Crossing Permit;
2 • North Dakota I-94 Crossing Permit;
3 • City of Fargo Right-of-Way Permit;
4 • City of West Fargo Right-of-Way Permits (five in total); and
5 • State of North Dakota and the City of West Fargo required stormwater
6 permits.
7

8 Additionally, a new permanent easement was procured for sections of the
9 pipeline where necessary, and the remaining pipe will be installed in the utility
10 easement.
11

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

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

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

3 A. Yes. As of mid-July 2021, the project has installed approximately 15,000 feet
4 of 12-inch steel pipe. The as-built survey, as well as hard and soft surface
5 restoration, has kept pace with pipe installation. Additionally, all horizontal
6 directional drilling has been completed, and the new regulator station has been
7 fabricated. The remaining project work includes installation of approximately
8 10,000 feet of pipe and the associated as-built survey and restoration work, a
9 limited amount of boring work, installation of the regulator station, and
10 completion of valve configurations at tie-ins to existing infrastructure and the
11 regulator station. Upon completion of this work, the line will be tested and
12 commissioned, and temporary control measures will be removed. Table 2
13 below provides the primary project milestones and the expected project
14 completion date.

15
16 **Table 2**
17 **Fargo Capacity Project Timeline**

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

18
19
20
21 The project is expected to be in service in the fall of 2021, but there may be
22 a small amount of restoration work necessary in the spring of 2022.

23
24 **C. Project Benefits**

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

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

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

10

11 Q. WILL THE FARGO CAPACITY PROJECT PROVIDE OTHER BENEFITS?

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

24

25 **D. Project Alternatives**

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

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

10
 11 Q. CAN YOU SUMMARIZE THE RESULTS OF THE COMPANY’S EVALUATION OF THE
 12 FARGO CAPACITY PROJECT ALTERNATIVES?

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

19
 20 **Table 3**
 21 **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

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

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

14
15 Q. PLEASE SUMMARIZE WHY THE COMPANY'S INVESTMENT IN THE FARGO
16 CAPACITY PROJECT WAS PRUDENT AND REASONABLE FOR NORTH DAKOTA
17 CUSTOMERS.

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

1 **IV. PEAKING PLANT INVESTMENTS**

2
3 Q. CAN YOU PROVIDE ADDITIONAL DETAILS ABOUT THE OPERATION OF THE
4 COMPANY'S PEAKING PLANTS?

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

8
9 The largest of the Company's three gas utility peaking plants is the Wescott
10 LNG Peaking Plant, located in Inver Grove Heights, MN. The Wescott
11 peaking plant can store approximately 2,145,000 Dth of LNG in two storage
12 tanks. Essentially, the Company purchases natural gas to store at Wescott
13 during the non-heating season when gas is readily available and typically
14 priced more favorably. Throughout the spring and fall "shoulder" months,
15 the Company liquefies purchased natural gas in a process that reduces its
16 temperature to approximately -260°F. The natural gas is then stored in a
17 liquefied state. Early in the winter, the Wescott plant "turns over" to
18 prepare for and implement the vaporization process whereby the liquefied
19 natural gas is vaporized and injected back into the system. The vaporization
20 process heats the pressurized natural gas back up to a temperature where it
21 returns to its gaseous state. Because Wescott cannot readily switch from
22 liquefaction to vaporization, the amount of natural gas in storage at the
23 beginning of the heating season is the maximum the Company will have in
24 LNG storage for the heating season.

25
26 The Company's other two peaking facilities store propane: the Sibley
27 Propane Air Peaking Plant in Mendota, MN and the Maplewood Propane

1 Air Peaking Plant in Maplewood, MN. The Sibley facility can store
2 approximately 114,000 Dth equivalent of propane, with a technical
3 maximum single-day withdrawal capacity is 46,000 Dth. The Maplewood
4 plant can store approximately 124,000 Dth equivalent of propane, with a
5 technical maximum single-day withdrawal capacity of 44,000 Dth. Once
6 propane is mixed with air, it can be injected into the natural gas system.
7

8 Because these plants generally are available to provide gas to firm customers
9 during peak conditions, the Company is able to avoid acquiring incremental
10 pipeline capacity to meet the same need, and use of these facilities provides
11 for additional gas supply options as we serve our North Dakota customers
12 during extreme weather conditions.
13

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

16 A. Capital projects that support our peaking plants include investments to
17 enhance reliability and maintain compliance with state and federal codes.
18 Investments may be related to routine plant maintenance or discrete projects
19 necessary to maintain operational reliability and compliance with state and
20 federal codes.
21

22 Q. HAS THE COMPANY MADE CAPITAL INVESTMENTS IN THESE PLANTS SINCE THE
23 2007 RATE CASE?

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

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

7
8 Q. WHAT ARE THE GAS OPS PLANT INVESTMENTS AFFECTING THIS RATE CASE?

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

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

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

1 Q. WHAT INVESTMENTS ARE NEEDED AT THE WESCOTT PLANT?

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

11

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

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

20

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

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

5
6 Q. WHAT ARE THE ALTERNATIVES TO MAKING THESE PEAKING PLANT
7 INVESTMENTS?

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

16
17 Q. HOW DO THESE PLANT INVESTMENTS BENEFIT NORTH DAKOTA CUSTOMERS?

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

1 **V. GAS OPERATIONS O&M EXPENDITURES**

2

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

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

7

8 **A. Types of Gas Ops O&M Expenses**

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

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

23

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

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

1 area where the work is completed. Accordingly, damage prevention costs in
2 Fargo are assigned fully to the North Dakota jurisdiction. That said, certain
3 Gas Ops O&M expenses are incurred on a Company-wide basis – for
4 example, management costs, environmental services, planning, and certain
5 engineering functions. These O&M expenses are allocated to the North
6 Dakota jurisdiction using the allocation methodology discussed by Mr.
7 Halama.

8
9 **B. Gas Ops O&M 2007-2022**

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

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

16
17 **Table 4**
18 **Gas Operations Distribution O&M 2007-2022**
19 **State of ND Gas Jurisdiction**

20

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

21

22
23 Q. WHAT DOES TABLE 4 INDICATE REGARDING GAS OPS DISTRIBUTION O&M
24 EXPENSES OVER TIME?

25 A. Table 4 illustrates since our last rate case that Gas Ops O&M expense has
26 increased on an overall basis. Distribution costs in 2022 are approximately
27 \$2.9 million higher than the 2007 test year in our last rate case, an average

1 increase of approximately six percent per year. This is due in large part to
2 customer growth over the same period, as well as inflation, with the increases
3 partially offset by ongoing efficiency efforts.
4

5 However, I note that Company O&M has been generally flat since 2015, with
6 some limited variability, due to the Company's ongoing efforts to increase
7 efficiency, contain O&M expenditures, and deploy cost reductions for
8 customers' benefit. These efforts offset cost increases due to inflation and in
9 other areas such as Damage Prevention.
10

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

12 A. The Damage Prevention program helps excavators and customers locate
13 underground gas infrastructure to avoid accidental damage and safety
14 incidents. NSP relies on a combination of internal labor and contractors for
15 the Company's Damage Prevention program. The primary purpose of this
16 program is to reduce damage to Company-owned buried facilities caused by
17 excavation. Excavation-related damage has the potential to impact public
18 safety and service reliability. This requirement is further supplemented by
19 state law in North Dakota. This program has been designed to ensure
20 compliance with state and federal regulations, and NSP relies heavily on
21 contractors to perform this work.
22

23 Q. WHY HAVE DAMAGE PREVENTION COSTS INCREASED?

24 A. North Dakota damage prevention costs increased by \$400,000 between 2019
25 and 2020 actuals and are further forecasted to increase by \$100,000 between
26 2020 and 2021. These increases are attributable to both an increase in the
27 volume of underground locate requests and a higher contract cost per locate

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

9
10 Q. WHY WAS THERE A COST INCREASE IN THE NEW CONTRACT THAT WENT INTO
11 EFFECT FEBRUARY 1, 2020?

12 A. At the time the contract was negotiated, before the COVID-19 pandemic, the
13 labor market for these jobs was tight. Additionally, the insurance premiums
14 to protect the vendor from damages caused by inaccurate locates performed
15 by their employees increased. Damages caused by vendors mislocating our
16 underground facility are covered by the vendor, which is a major factor in our
17 decision to utilize outside vendors for this type of work.

18
19 Q. YOU NOTED EARLIER THAT O&M COSTS HAVE REMAINED LARGELY FLAT
20 SINCE 2015. CAN YOU EXPAND ON THE REASON FOR THIS TREND?

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

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

6
7
8

VI. CONCLUSION

9 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

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

21

22 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

23 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).

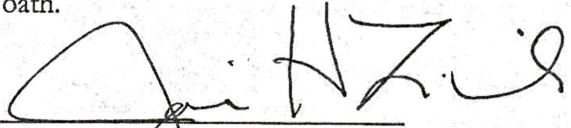
In April 2012, I was promoted to Director of System Strategy and Business Operations for Xcel Energy Services Inc. (XES) the "service company" subsidiary of Xcel Energy, Inc. (Xcel Energy), a registered holding company. In this capacity, I am responsible for the long-term gas capacity planning for the 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.

1 STATE OF NORTH DAKOTA
2 BEFORE THE
3 PUBLIC SERVICE COMMISSION
4
5

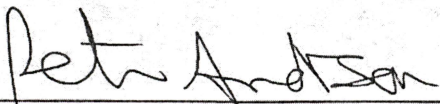
6 In the Matter of the Application of)
7 Northern States Power Company for Authority)
8 To Increase Rates for Natural Gas Service) Case No. PU-21-____
9 In North Dakota)
10
11

12 AFFIDAVIT OF
13 Joni H. Zich
14
15

16
17 I, the undersigned, being duly sworn, depose and say that the foregoing is the
18 Direct Testimony of the undersigned, and that such Direct Testimony and the
19 exhibits or schedules sponsored by me to the best of my knowledge, information
20 and belief, are true, correct, accurate and complete, and I hereby adopt said testimony
21 as if given by me in formal hearing, under oath.
22

23
24 
25 _____
26 Joni H. Zich
27

28
29
30 Subscribed and sworn to before me, this 19 day of August, 2021.
31

32 
33 _____
34 Notary Public Wisconsin
35 My Commission Expires: 4/15/2024
36 County of Sawyer
State of Wisconsin.

