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Direct Testimony and Schedules
Alicia E. Berger

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in Minnesota

Docket No. G002/GR-25-356
Exhibit___(AEB-1)

Gas Operations

October 31, 2025

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have a Bachelor of Science degree in Business Management from Saint Catherine University, Saint Paul, Minnesota. I have been employed by Xcel Energy Services Inc. since 2007. Throughout my career, I held positions of increasing responsibility in the areas of damage prevention, operations planning and operational performance management, and have led key projects and served as a liaison to represent the organization with key business partners. I was promoted to the position of Director of Gas Operations within the Gas department in January 2020 and subsequently Regional Vice President, Gas Operations in August 2023. In my current role, I direct the development and implementation of short- and long-term business plans that support achievement of objectives and lead the development and implementation of labor strategies that help ensure flexible and effective utilization of resources. I am responsible for the operation and maintenance of regional gas distribution, which includes gas emergency response, as well as for the development, execution, and oversight of the gas safety plan and the safety performance of the organization. A description of my qualifications, duties, and responsibilities is provided as Exhibit___(AEB-1), Schedule 1.

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

A. The purpose of my Direct Testimony is to present an operational perspective of NSPM's natural gas business and detail the major drivers of change in the Company's Gas Operations business and costs to support the Company's rate requests in this proceeding. I provide my testimony in the sections described below.

In Section II, I provide an overview of the Company's Gas Operations and the work NSPM has undertaken over the last several years, as well as progress made with respect to a number of key safety and reliability metrics. I provide an overview of the NSPM gas system landscape and business. I also introduce the core areas of capital and O&M investment undertaken by the Gas Operations area, which include **Safety**, **Reliability**, connecting **New Customers**, and undertaking **Mandated Relocations** of Gas infrastructure. I note that in the Company's last gas rate case filed in Docket No. G002/GR-23-413 (the 2024 Gas Rate Case), capital investments and O&M budgets related to gas peaking plants were included in the Distribution business area's budgets and addressed in my Direct Testimony. However, as of January 1, 2025, the responsibility for the budgets and operations of the gas peaking plants were moved to the Company's Energy Supply business area. As such, Company witness Randy A. Capra supports gas plants capital and O&M budgets in his Direct Testimony in this case.

In Section III, I discuss the Company's Gas Operations capital investments, including budget development, capital investment trends, and recent major planned investments. I also discuss the Company's key capital additions that will be placed in service in 2026, including both routine work to manage the gas system and larger discrete projects.

In Section IV, I support the Company's Gas Operations O&M expenses. I provide an overview of the Gas Operations O&M levels over the last three years as compared to the current year and our 2026 test year. I walk through the O&M budget in detail, describing how Gas Operations incurs O&M expense and manages these costs over time.

In Section V, I address compliance items specific to Gas Operations from prior Commission orders implementing requirements for this rate case.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In my Direct Testimony, I provide support for the Company's capital and O&M investments included in the Company's test year in this case. Overall, I discuss how the NSPM natural gas system provides safe and reliable service to our Minnesota customers. I also discuss how we continue to address the evolution of the system, changes in natural gas regulation, and cost management efforts the Company is undertaking. Many of our capital investments in the gas system are "routine" in nature, in the sense that they involve small investments to connect new customers, ensure system safety and integrity, relocate facilities where necessary, and ensure sufficient pipeline capacity to serve our customers. I illustrate that the Gas Operations drivers of the need for this rate increase are largely related to certain discrete capital projects, programmatic reliability and safety investments, and advanced mobile leak detection. I also explain certain cost increases, such as those related to increased labor and underground Gopher State One Call "locates" associated with our Damage Prevention program, which are driven by increasing volume, complexity, and outside service costs. Overall, I demonstrate that the Gas Operations capital and O&M requests in this rate case are reasonable and support the public's interest in a safe, reliable, sound gas system.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into the following sections:

- *Section II* – Gas Operations Overview
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – Compliance Issues
- *Section VI* – Conclusion

II. GAS OPERATIONS OVERVIEW

A. Gas Operations System and Gas Business

Q. PLEASE PROVIDE AN OVERVIEW OF NSPM'S GAS OPERATIONS.

A. NSPM provides gas sales and transportation service to customers in several communities across the state of Minnesota. We operate facilities in 29 of the 87 counties within the state. A map of our gas service area is provided as Exhibit___(AEB-1), Schedule 2. The Company provides natural gas service to approximately 492,000 residential, commercial, and industrial customers in Minnesota, as well as to gas-fired electric generation facilities.

Q. WHAT TYPES OF INFRASTRUCTURE ARE INCLUDED WITHIN NSPM'S GAS SYSTEM?

A. Our gas system in Minnesota includes approximately 9,800 miles of distribution mains and 64.1 miles of transmission pipeline, and over 494,000 meters, as well as regulator stations and other supporting infrastructure. We also maintain one liquefied natural gas (LNG) plant and two propane air plants to provide gas to our firm customers on a peaking basis. Company witness Capra discusses the peaking plants in his Direct Testimony. Unlike our electric system, our gas system serves primarily as a local distribution company.

Q. WHAT ARE THE MAIN FUNCTIONS PERFORMED BY THE GAS OPERATIONS BUSINESS UNIT?

A. The Gas Operations business unit provides all the major functions to deliver natural gas from upstream interstate pipelines (Northern Natural Gas (NNG) and Viking Gas Transmission (VGT) to the customer's meter and ensures public safety through compliance with state and federal pipeline safety regulations. These functions include planning, engineering, design, metering, compliance, responding to gas emergencies, locating underground gas facilities, construction and maintenance on the system, coordinating with communities to relocate our facilities when necessary for municipal projects like water and sewer projects, and complying with all state and federal regulations, just to name a few.

Q. WHAT IS THE BASIC MISSION OF NSPM'S GAS BUSINESS?

A. Our mission is to provide safe, reliable, affordable, and environmentally responsible service to our Minnesota customers. We understand that natural gas service is critical to the State of Minnesota and its residents. When firm customers need natural gas for home heating, critical industrial processes, and other end uses, we must be ready to provide that service on demand. Moreover, we must design and operate our system to ensure the safety of our customers, our employees and contractors, and the public. To do this, the Company follows federal and state codes and regulations and relies on best practices obtained from peer benchmarking. The individual characteristics of infrastructure within NSPM's natural gas system further drive the Company's planning and operation.

In addition, as leaders in clean energy and carbon emissions reduction, NSPM is committed to work to reduce natural gas emissions from (1) our upstream producers and interstate pipelines, (2) the operation of our local distribution system, and (3) our customers at their homes and businesses. Company witness Jeff R. Lyng discusses these efforts in more detail.

Q. WHAT ARE THE MAJOR PRINCIPLES, RULES, AND REGULATIONS THAT GUIDE NSPM'S INVESTMENTS IN ITS GAS SYSTEM ON BEHALF OF CUSTOMERS?

A. At a high level, the basic principle is to ensure that the natural gas (a combustible substance) we deliver to customers remains safely in our transmission and distribution pipelines until the point of use. This principle is put into practice through a complex set of rules and regulations that govern our work at the federal, state, and local levels.

At the federal level, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is the primary federal administration responsible for ensuring that pipelines are designed, constructed, operated, and maintained in a safe, reliable, and environmentally sound manner. PHMSA oversees the development and implementation of regulations concerning pipeline design, construction, maintenance, operations, and emergency response. As discussed below, these responsibilities are shared with the State of Minnesota.

Although I am not an attorney, I am aware that there are several federal regulations that pertain to NSPM's Gas Operations, including:

- 49 Code of Federal Regulations (CFR) Part 191 – requirements of natural gas pipeline operators to report incidents, safety-related conditions, and to submit annual summary data;
- 49 CFR Part 192 – minimum safety requirements for gas pipeline materials, design, construction, corrosion control, testing, personnel qualification, maintenance, and operations. The Distribution Integrity Management Program (DIMP) and Transmission Integrity Management Program (TIMP) rules are contained in this part, as well as rules governing the minimum safety standards for underground natural gas storage facilities (UNGSFs);
- 49 CFR Part 193 – prescribes safety standards for liquefied natural gas (LNG) facilities;
- 49 CFR Part 196 – regulations for the protection of underground pipelines from excavation activity; and
- 49 CFR Part 199 – programs for preventing alcohol misuse and to test gas employees for the presence of alcohol and prohibited drugs.

The State of Minnesota, Department of Public Safety, Office of Pipeline Safety (MNOPS), through the state certification process outlined in 49 U.S. Code 601, is authorized to act on behalf of PHMSA for the oversight, enforcement, and regulation of intrastate pipelines in the state of Minnesota. MNOPS has adopted the federal regulations outlined above and further regulates natural gas pipeline safety and one-call excavation rules to ensure consumers receive safe service.

Federal, state, and local (*e.g.*, city and county) governments are responsible for overseeing the construction of new distribution pipeline infrastructure. In addition, some of these local governments provide the Company with franchise agreements that enable us to install our natural gas infrastructure within road rights-of-way through the communities that we serve.

Q. HOW DO THESE RULES AND REGULATIONS ALIGN WITH THE WORK OF THE COMPANY'S GAS OPERATIONS?

A. These rules and regulations play a large role in how we do business, particularly with respect to the safety of NSPM's Gas Operations. Additionally, PHMSA, MNOPS, and other state and local requirements rules and regulations, as well as industry organizations, such as the American Petroleum Institute (API), often drive specific investment needs for our system, for both capital and O&M. Throughout my Direct Testimony, I will be describing how these rules drive specific investments the Company is undertaking.

1. NSPM Gas System Landscape

Q. PLEASE IDENTIFY ANY MAJOR CHANGES TO NSPM'S GAS SYSTEM SINCE THE COMPANY'S LAST MINNESOTA GAS RATE CASE.

A. NSPM's last Minnesota gas rate case was filed on November 1, 2023 with a 2024 test year, in Docket No. G002/GR-23-413 (the 2024 Gas Rate Case). The Commission's Order accepting the Settlement agreement and setting rates in that docket was issued on March 5, 2025. Although the Company's gas system has not changed significantly since we filed our last rate case, the Company added 3,103 gas services and approximately 64 miles of distribution main in 2024, which includes both new equipment and the necessary replacement and refurbishment work on our existing system. We also continue to invest in ways to improve our existing natural gas system to support safer, more reliable, and cleaner energy services to our customers. These investments include updates to our system management and maintenance, while responding to customer locate requests and gas emergency calls.

There have also been continuing changes in the regulatory landscape as well as continued improvements to our system reliability and safety. Both of these will be discussed in further detail below. The industry also has been working toward continually improving public and environmental safety, through reduction of methane emissions and incorporation of other renewable gas sources, such as Renewable Natural Gas and hydrogen blending. I discuss some of these changes below, and Company witness Lyng discusses the Company's Net-Zero Vision for Natural Gas and associated emission reduction efforts related to the natural gas business.

Q. CAN YOU GENERALLY DESCRIBE SOME OF THE INDUSTRY RULES AND REQUIREMENTS THAT IMPACT THE NSPM GAS SYSTEM?

A. Yes. As we discussed in our 2024 Gas Rate Case, there have been significant changes in industry legislation, regulations, and best practices in the last decade-plus. For example, in 2009, PHMSA published the final DIMP rule establishing integrity management requirements for gas distribution pipeline systems. Under DIMP, all gas distribution operations were required to develop robust programs to identify, prioritize, remediate, monitor, and report on risks to the distribution system, progress to address issues, and plans for improvements. The Company complied with DIMP requirements by implementing a program and plan in 2011 and continues to operate within the plan in compliance with PHMSA requirements through the present day.

It is important to remember that during the same period PHMSA began implementing new pipeline safety rules, there were several natural gas incidents around the country that caused significant loss of life and property. One occurred in San Bruno, California in 2010, and another occurred in Allentown, Pennsylvania in 2011. Incidents such as these heightened system operators' attention to pipeline safety and caused Congress, PHMSA, and system operators around the country to take new steps to help ensure the safety and integrity of natural gas systems, particularly with respect to older construction materials and practices that were or are no longer considered best practice.

For example, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act) led to significant additional requirements and industry best practices to protect the safety and integrity of natural gas infrastructure. Although more than a decade has passed, the 2011 Pipeline Safety Act continues to generate regulations governing the natural gas industry. For example, the three parts of the Gas Transmission Mega Rule were finalized by PHMSA in 2019, 2021, and 2022. This rule introduced a host of additional pipeline safety and integrity standards and requirements. Also stemming from the 2011 Pipeline Safety Act, PHMSA published further pipeline valve rupture detection safety standards in 2022.

More recently, there has been additional legislation and regulation affecting the gas distribution system. The most recent pipeline safety reauthorization, the

Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020, has initiated several proposed rulemakings and other requirements that will have a large effect on distribution assets. Under the PIPES Act of 2020, Congress passed legislation for a "self-executing" mandate requiring operators to update their inspection and maintenance plans to address eliminating hazardous leaks and minimizing releases of natural gas. This mandate to operators has been codified under 49 U.S. Code 60108 and requires operators to revise or create procedures to minimize releases of gas. Also stemming from the PIPES Act of 2020, PHMSA released a Notice of Proposed Rulemaking (NPRM) for Gas Pipeline Leak Detection and Repair in 2023 and provided an unpublished final rule on January 16, 2025. PHMSA has submitted another NPRM related to distribution pipeline safety initiatives to address legislative requirements based on the 2018 Merrimack Valley low-pressure distribution incident.

Finally, PHMSA has issued a series of updates to the standards incorporated by reference (IBR) in 49 CFR 192. On April 29, 2024, PHMSA released a final rule titled "Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments" to update 18 technical references to Part 192. These updates generally revised the material design specifications and technical standards used for gas distribution systems incorporated, found respectively in API, ASTM, ASME, ANSI, and NFPA. These standards were effective on June 28, 2024 but were under a stay of enforcement until January 1, 2025. On July 1, 2025, PHMSA published 28 Direct Final Rules of which 14 regulations were focused on updating technical references and industry standards for Part 192. The most IBR updates are scheduled to go in effect on January 1, 2026.

Q. HOW DO THE INDUSTRY RULES AND REQUIREMENTS DISCUSSED ABOVE AFFECT THIS RATE CASE?

A. The Company recovers a significant portion of the costs associated with the rules and requirements discussed above through the Gas Utility Infrastructure Cost (GUIC) Rider. With Commission support and new legislation, we have extended the (GUIC) Rider to support the safety and integrity needs of our system, including for TIMP, DIMP, and mandated relocation work,[1] consistent with PHMSA requirements and specific obligations as natural gas system operators.

That said, these rules and requirements, as well as pipeline safety incidents in other parts of the country, highlight our obligations and the importance of investing in the safety of our customers and the public as a whole. Moreover, like other riders, the GUIC Rider does not allow for recovery of all necessary utility costs and investments to operate the system; as a result, rate cases are still required from time to time. The Company was able to forego filing a gas rate case between 2009 and 2021, for example, due to rising sales during that period and cost recovery allowed under the GUIC Rider. However, changes in sales growth and the need to continue to invest in the safety and reliability of the system for our customers, particularly as the system continues to age, contribute to the need for this current rate case.

Q. PLEASE ELABORATE ON WHAT YOU MEAN BY THE NEED TO CONTINUE TO INVEST IN THE SAFETY AND RELIABILITY OF THE SYSTEM.

[1] The Minnesota Legislature amended Minnesota Statutes § 216B.1635 (GUIC Statute) to extend the expiration date to June 30, 2028, which will further support this important safety work. 2023 Minn. Laws Ch. 60, art. 12, § 66.

A. There are continually emerging risks that need to be mitigated as any gas system ages, and we must make ongoing assessments of and investments in our assets, our performance, and our customer service. Like the rest of the gas industry in the United States, NSPM continues to focus on removing operational and safety risks from its system by operating in a proactive manner while containing costs. This work includes replacement of aging assets, responding to emergencies faster, and regularly performing leak surveys of the Company's system – as well as investments in our system related to safety and reliability that are not recoverable under the GUIC Rider.

Q. AT A HIGH LEVEL, CAN YOU PROVIDE INFORMATION REGARDING HOW THE GUIC RIDER FUNCTIONS?

A. Yes. Costs that qualify for recovery under the GUIC Statute are those that are not already reflected in the utility's rates and that are incurred in projects involving (1) natural gas facilities that must be replaced due to road construction or other public works projects (mandated relocation), and (2) the replacement or modification of existing facilities required by a federal or state agency (TIMP and DIMP). The Commission has consistently recognized that the Company's TIMP and DIMP projects are reasonable and in the public interest by allowing for efficient rider recovery of costs since the Company's inaugural GUIC petition filed in Docket No. G002/M-14-336. Since the 2015 inception of NSPM's GUIC Rider, the Company has completed the replacement of over 510 miles of high- and medium-risk, aging, corroded, and otherwise damaged gas distribution pipeline, as well as the replacement of approximately 22,300 aging distribution service lines.

In addition, in the Company's 2023 GUIC Rider proceeding (Docket No. E002/M-22-578), the Company proposed, and the Commission approved, recovery of all mandated relocation projects under the GUIC Rider going forward, as allowed by the GUIC Statute.[2] Mandated relocations are capital projects that require NSPM to move existing infrastructure in order to meet federal, state, or local requirements. This includes relocating facilities that are in direct conflict with street expansions within public rights-of-way and safety-related work required by a governing authority. The Company will also reflect any reimbursements as offsets to total revenue requirements in the GUIC Rider annual true-up filings.

Q. HOW DOES THE GUIC RIDER COST RECOVERY FIT WITH THE COMPANY'S TOTAL GAS OPERATIONS INVESTMENTS?

A. To the extent costs are recovered through the GUIC Rider, they are excluded from base rates until they are transferred to base rates. As part of updating base rates, the Company is proposing to roll rate base and cost components associated with GUIC projects placed in service on or before December 31, 2025 into final rates at the completion of this rate case. In his Direct Testimony, Company witness Benjamin C. Halama describes the mechanics of rolling capital GUIC projects into base rates.

2. Gas Operations Areas of Service

Q. PLEASE DESCRIBE THE GAS OPERATIONS BUSINESS UNIT'S KEY AREAS OF SERVICE IN MORE DETAIL.

[2] Internal labor costs associated with mandated relocation projects are not recoverable from the GUIC, but are instead recovered through base rates.

A. Now that our Plants work has moved to the Energy Supply business area, there are four primary areas of operation for the Gas Operations business area. First and foremost, **Safety** and **Reliability** are the key areas of focus for Gas Operations. In addition, we address **New Business** resulting from new customers and customer growth, and undertake infrastructure **Relocations** mandated by city, state, or federal authorities. These efforts are not only designed to meet our service obligations from a PHMSA and state law perspective, but also to serve our customers effectively and efficiently.

Q. CAN YOU PROVIDE ADDITIONAL DISCUSSION OF THESE FOUR CORE AREAS?

A. Yes. I will discuss each in turn below.

1. **<u>Safety</u>:** Safety rules and regulations require the Company to establish TIMP and DIMP plans. At a high level, TIMP and DIMP rules require operators to (1) know their assets, (2) identify risks and threats to those assets, and (3) proactively mitigate those risks/threats. For NSPM, as I noted above, the costs to comply with TIMP and DIMP are recovered through either the GUIC rider or base rates.

   For public safety, the Company is also required to locate its underground gas infrastructure free-of-charge, in compliance with Minnesota Statutes § 216D.04, subdivision 3, for anyone who calls Minnesota 811 and requests a locate. We accomplish this work through our Damage Prevention program. Over 90 percent of NSPM's locate costs are incurred on behalf of others, and only about 10 percent are related to NSPM's own construction projects. Additionally, every gas operator within the United States is obligated to respond to customer calls when they think they smell natural gas or have any gas emergency.

2. **Reliability:** Our customers need reliable service. Customers depend upon natural gas to heat their homes and water, cook their meals, dry their clothes, and support commercial and industrial activities within the state. Consistent with our tariff, NSPM must stand ready to provide our customers with safe and reliable natural gas service. In order to do so, NSPM must adequately maintain, renew, and operate its regulator stations, meters, and every other aspect of the system. When our assets are no longer adequate to meet customers' safety and reliability needs, the Company must replace, reinforce, or rebuild those parts of our system. Additionally, when safety and service reliability demand exceeds the capacity of the Company's human resources available to operate the system, we must adjust our staffing models accordingly.
3. **New Business:** As a general matter, the Company will extend service to any new customer who requests gas service within its service territory under the rules of its tariff, subject to the availability of gas. This includes not only laying the service line and setting the meter to a customer's facility, but also installing the gas main to which the service line connects. NSPM also operates an integrated system of distribution and transmission assets. Customer growth on the distribution system can cause a capacity shortage on upstream distribution and transmission pipelines and regulating facilities. To ensure gas service to each firm customer during a cold peak hour or design day, the Company must have adequate capacity across its entire integrated system.
4. **Relocations:** NSPM is also required by state, county, and local government bodies to relocate our gas infrastructure that resides in road right-of-way when a relevant entity's work conflicts with our facilities. NSPM's franchise agreements with the communities it serves require the

Company to move or relocate our infrastructure when requested by a government body. This includes, but is not limited to, infrastructure work on water, sewer, transportation, and other major infrastructure. The costs associated with relocating our natural gas infrastructure are borne by NSPM and ultimately impact our customers through cost-of-service ratemaking. As noted above, mandated relocation costs are primarily recovered through the GUIC Rider beginning in 2023, with a small portion of the costs recovered through base rates.

B. Operational Enhancements

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

A. In this section of my testimony, I build on the discussion earlier in my testimony regarding our investments in serving our customers, highlighting enhancements to our system and customer service. In particular, I illustrate how the Company has enhanced its performance over time in several areas that underscore the value of our investments in the NSPM gas system.

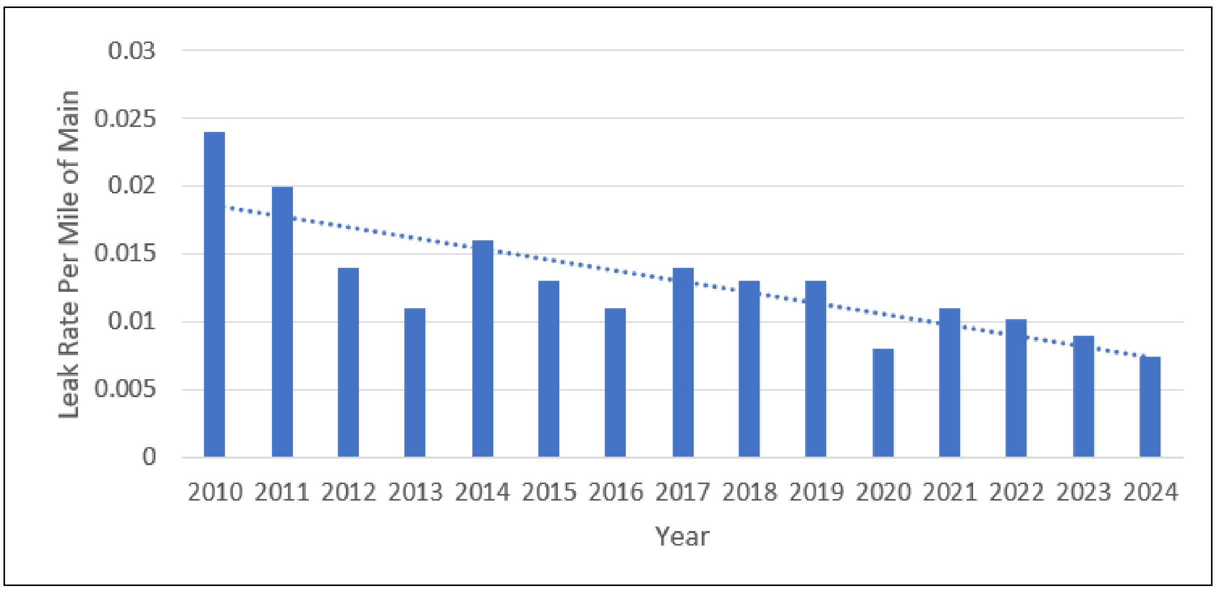
Q. CAN YOU PROVIDE AN OVERVIEW OF HOW THE COMPANY HAS ENHANCED THE SYSTEM AND CUSTOMER SERVICE?

A. Yes. NSPM's investments in the gas system, which are recovered in base rates and through the GUIC Rider, enable us to continue providing safe and reliable customer service, while also continually improving in various metrics that are indicators of the health and safety of our system. Such key metrics include leak ratios, quantity of pipeline renewals, number of transmission pipeline assessments, the quality of our transmission pipeline records, and damages per 1,000 locates. Overall, improvements in these metrics in recent years help demonstrate the Company's proactive and prudent investment in its gas system.

Q. WHAT PROGRESS HAS NSPM MADE ON LEAK RATIOS?

A. NSPM has reduced its distribution leak ratio (that is, the ratio of distribution main leaks per mile of main excluding excavation damages) by approximately 69 percent since 2010. This progress is a result of the Company's successful efforts and investments to target renewal of the highest-risk main pipelines through its capital pipeline replacement programs. Figure 1 below provides annual NSPM distribution main leak ratios from 2010 through 2024, on a Minnesota-only basis, showing an overall decline in the past decade-plus.

Figure 1
Historical NSPM (Minnesota) Distribution Leak Ratios



Q. WHY IS THERE VARIABILITY IN DISTRIBUTION LEAK RATIOS?

A. The Code of Federal Regulations, Part 192, Subpart M requires operators to conduct periodic leak surveys of their pipeline systems. Generally, the Company conducts leak surveys over the same stretches of pipe every three years. However, depending on scheduled work activities, the Company does shift leak surveys of stretches of pipe to different years to improve work efficiency. In addition to the periodic leak survey process, leaks are also identified by other means (customer calls, etc.) that are not related to the three-year survey cycle. As such, some variation of leak rates from year to year is expected. With periodic leak surveys conducted on a system that is aging over time, it is expected that new leaks will be identified through this process on an ongoing basis. The important point, however, is that the overall trend has been a substantial decline over time.

Q. HOW DOES A DECLINING LEAK RATE BENEFIT CUSTOMERS?

A. Overall, a declining leak ratio indicates that more gas is staying in the pipeline where it belongs. This provides a safety benefit to customers and the communities we serve, as it reduces the risk of catastrophic incidents. Improved pipe integrity and reduced leaks also provides environmental benefits, as these efforts also reduce and avoid methane emissions from the natural gas system.

Q. WHAT PROGRESS HAS BEEN MADE ON PIPELINE RENEWALS?

A. Between 2015 and 2024, NSPM renewed over 580 miles of main and approximately 21,000 services through its pipeline replacement program (with recovery through the GUIC). This progress reflects investments in both larger and smaller projects (in terms of scope, pipe diameter, etc.). Overall, these investments drive down leak rates, providing a higher level of safety to our customers, as well as lower methane emissions.

Q. PLEASE DISCUSS THE COMPANY'S PROGRESS ON TRANSMISSION PIPELINE ASSESSMENTS.

A. Transmission pipeline assessments are necessary to detect safety and reliability issues, and are accomplished through a variety of methods, including in-line inspections, external corrosion direct assessment, internal corrosion direct assessment, and pressure testing. NSPM has assessed 97 percent of its transmission pipelines through 2024, and 100 percent completion is forecasted for 2026 via all assessment methods. Capital and O&M costs associated with performing transmission assessments are recovered through the GUIC until they are rolled into base rates.

Q. WHAT IS THE SIGNIFICANCE TO CUSTOMERS OF THE PROGRESS ACHIEVED AND ANTICIPATED ON TRANSMISSION PIPELINE ASSESSMENTS?

A. Transmission pipeline assessments provide valuable information about the health and condition of our high-pressure (HP) transmission lines. Knowing this information allows us to remediate any anomalies discovered, providing a safer environment for our communities and customers that live, work, and recreate around our transmission pipelines.

Q. WHAT IMPROVEMENTS HAVE BEEN MADE TO THE COMPANY'S TRANSMISSION PIPELINE RECORDS?

A. The Company has completed the review of all pressure test records on its transmission lines for traceability, verifiability, and completeness, and we are in the process of reviewing documentation for the stations along the main lines. Efforts are ongoing to evaluate material records. Having complete, traceable, and verifiable pressure test records ensures that our transmission pipelines not only meet PHMSA requirements but also ensure that they are operating at or beneath their maximum allowable operating pressure (MAOP), providing a safer environment for our customers and communities.

Q. WHAT OVERALL CONCLUSIONS CAN BE DRAWN FROM THESE IMPROVEMENT EFFORTS?

A. The prior discussion illustrates that the Company's investments in safety, reliability, and system integrity are enhancing our overall system health and customer service capabilities. It also supports our plan to continue these investments into the future, as our safety and reliability work is not yet done and we must always remain vigilant to protect the health of our system, our customers, and the public. We anticipate additional system needs going forward, as described in the remainder of my Direct Testimony.

III. CAPITAL INVESTMENTS

A. Overview of Capital Investments

Q. WHAT KEY STRATEGIC NEEDS AND FOCUS DRIVE GAS OPERATIONS' CAPITAL INVESTMENTS?

A. The focus of our capital investments has been and remains our mission to provide safe and reliable service to our customers – by both connecting and serving new customers and ensuring continued safety and reliability to our existing customers. This requires compliance with federal and state pipeline safety standards and industry best practices, as well as investments to move existing gas infrastructure to relocate facilities that are in direct conflict with street expansions within public rights-of-way and safety-related work required by the governing authority.

Q. HOW DO GAS OPERATIONS' CAPITAL INVESTMENTS BREAK INTO CAPITAL BUDGET GROUPINGS THAT REFLECT THOSE GOALS?

A. Our capital projects recovered through base rates fall into three capital budget groupings, depending on the primary purpose of the project. These groupings are based on our core work, described above: Safety, Reliability, and New Customer Business. As I previously discussed, Mandated Relocation capital investments are largely recovered through the GUIC, except for internal labor, and therefore are not included in base rates nor discussed in detail in the remainder of my Direct Testimony.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION REGARDING THE TYPES OF CAPITAL INVESTMENT NEEDED IN EACH OF THE THREE CATEGORIES YOU ADDRESS IN YOUR DIRECT TESTIMONY?

A. Yes. The categories of capital investment largely track the areas of service for Gas Operations I discussed earlier in my testimony. These include the following:

<u>Safety</u>: Maintaining safety requires a multi-faceted work and capital investment approach that considers the complex nature of the system and the multiple risks that any natural gas system faces. Much of the safety capital work is focused on maintaining the integrity of the Company's gas system assets so they can function as intended and provide safe and reliable service to customers. This includes infrastructure enhancements aimed at reducing leaks – such as our investment in advanced mobile leak detection technology, which I address later in my testimony – strengthening safety through initiatives like the Inside Meter Move Out program, also discussed later, and renewing service mains and pipelines, among other efforts.

<u>Reliability</u>: Maintaining a reliable system, in a proactive manner, requires identifying the capacity needs of the system and responding when a capacity need is identified. In addition, the Company has projects and programs for routine asset health and capacity investments to maintain day-to-day system reliability.

<u>New Customer Business</u>: As I previously noted, the Company will extend service to any new customer that requests gas service within its service territory under the rules of its tariff, subject to the availability of gas. When there is no existing connection to the customer's property, the Company must make capital investments to install new service lines, meters, and other infrastructure to extend service to the residential, commercial, or industrial property.

Q. ARE THERE OTHER AREAS OF THE COMPANY THAT SUPPORT THE WORK OF GAS OPERATIONS IN SERVING CUSTOMERS?

A. Yes. While I support the capital investments for Gas Operations, there are many other areas of the Company that support the operation of our gas system and the distribution of natural gas to our customers. Some examples include the Shared Corporate Services Business Areas, which conducts a variety of activities on behalf of Xcel Energy and its operating companies – such as Property Services, Fleet Operations, and Technology Services – as discussed in the Direct Testimonies of Company witnesses Gregory J. Robinson, Michele A. Kietzman, and Megan N. Scheller.

Q. CAN YOU PROVIDE ADDITIONAL PERSPECTIVE ON WHY ADEQUATE SERVICE CENTER FACILITIES ARE IMPORTANT TO GAS OPERATIONS EMPLOYEES AND CUSTOMERS?

A. Yes. As Company witness Kietzman describes, Property Services is responsible for operating and maintaining the safe, reliable, and efficient service centers where our field employees are based and conduct front line operations on behalf of customers. The Company's service centers are located throughout our service territory to enable our employees to meet our service obligations, respond to emergencies, and serve our customers effectively and efficiently. The service centers are utilized by our field employees to attend training, gather for meetings, review plans and designs with other business partners, as well as store material, fleet, and other critical items necessary to perform their work in a secure location. Service centers also provide space for front line employees to perform work such as welding, meter testing, and prefabricating meter sets. Service centers must be maintained to provide adequate space in optimal locations to serve current or expected growth in an area, considering how response times may be impacted by increased distance to customers or that the current site is too small to accommodate the volume of work necessary to serve customers. Property services works with Gas Operations to provide safe, secure service center facilities with adequate space to help ensure service centers meet the need identified by the operations team.

Q. FROM A GAS OPERATIONS PERSPECTIVE, WHY ARE FLEET VEHICLE AND INFRASTRUCTURE INVESTMENTS IMPORTANT TO COMPANY EMPLOYEES AND CUSTOMERS?

A. As Company witness Robinson discusses, the Fleet organization (part of Supply Chain) supports Gas Operations by providing the appropriate number of safe and reliable Company vehicles and equipment that our field employees need to do their jobs on a day-to-day basis. As shown in the Direct Testimony of Company witness Robinson, the vast majority of Fleet capital additions in 2025 and 2026 support Gas Operations. Providing gas distribution service to our customers includes construction, maintenance, and repair work – such as adding or repairing gas mains and service lines and related infrastructure; installing, maintaining, repairing, or replacing meters; addressing service connections; vegetation management; and leak inspection – requiring constant travel throughout our service territories. This requires the use of not only trucks and cars, but also a variety of different types of construction equipment. Items such as trailers, excavation, tapping, and vacuum equipment position workers to complete their work efficiently and effectively. Fleet must be capable of supporting Gas Operations under all weather conditions to provide safe and reliable service to our customers and our front line must be prepared and equipped to handle seasonal challenges such as ground frost.

Fleet plays an essential role in preventing delays in responding to the needs of our system and the communities we serve. Investments in Fleet is fundamental to our ability to operate and maintain our system safely, reliably, and efficiently. Our front-line workers must be able to transport our construction equipment in a timely and efficient manner to various jobsites. Additionally, field personnel must have access to reliable vehicles and equipment to ensure we can respond swiftly and safely to emergencies. In short, these aspects of the business all work hand-in-hand to serve our customers.

Q. HOW DO INVESTMENTS IN INFORMATION TECHNOLOGY SUPPORT THE WORK OF GAS OPERATIONS ON BEHALF OF CUSTOMERS?

A. As Company witness Scheller discusses, Technology Services provides the technologies and supporting services necessary for system reliability and security as well as operational decision-making. This includes supporting Gas

Operations employees' hardware, software, and network connectivity needs, and protecting the security of the Company's data from cyber-attacks. Information technology is critical to all aspects of the gas operations business, from crew and infrastructure management to employee communications to core business functions.

B. Capital Budget Development and Management

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

A. In this section, I will provide an overview of Gas Operations' capital budgeting process and management, which is utilized to develop the capital budget for each of the capital budget groupings that form the basis for our test year. I offer this information as additional support for the forecasted capital included in the Company's rate request.

Q. HOW DOES NSPM BUDGET FOR CAPITAL SPENDING FOR ITS GAS OPERATIONS BUSINESS?

A. We have a well-defined process for identifying, ranking, and budgeting gas capital projects. This process involves the identification of potential system risks and mitigations (associated solutions), review of mitigations for accuracy, completeness, and reasonableness, and prioritization of projects. The specific projects to be completed are based on these prioritizations in combination with assessment of overall budget dollars available. Projects that are funded may then be classified as either "discrete" or "routine" and assigned in-service dates or closing patterns based on the attributes of the work and receive oversight throughout work deployment.

Q. YOU REFER TO "RISKS," "SOLUTIONS," "MITIGATIONS," AND "PROJECTS." CAN YOU EXPLAIN WHAT YOU MEAN BY THESE TERMS IN THE CONTEXT OF DEVELOPING A CAPITAL BUDGET?

A. "Risks" are potential detrimental impacts or threats to safety, the quality/reliability of our service, environmental quality, our ability to meet our legal obligations, or our financial standing. These identified risks result in initiatives that address the risks. These initiatives, in turn, often require capital expenditure. In the capital budgeting process, potential "solutions" or "mitigations" are essentially "projects" (*i.e.*, work to be performed that will mitigate a certain risk or set of risks). These projects are the focus of the capital budget process. Projects are evaluated against each other based on their costs, how effectively they address certain risks, and how critical the risks are.

Q. PLEASE EXPLAIN THE PROCESS OF MANAGING CAPITAL COSTS AFTER THE CAPITAL BUDGET IS DEVELOPED.

A. Gas Strategy, Operations, and Engineering within Gas Operations, along with the corporate Finance organization, monitors all distribution and capital dollars to ensure that authorized projects align with the established budget. Detailed monthly reports are produced that compare actual capital expenditures and plant in-service to budgeted levels for routine and specific projects. Key stakeholders within the organization meet to review program and specific project capital expenditures and variances. Adjustments and corrective measures are implemented as needed.

Q. WHAT INCENTIVES ARE IN PLACE TO PROMOTE THE ACCURACY OF THE CAPITAL BUDGET?

A. Management employees that have job responsibilities with a direct impact to capital budget expenditures and plant in-service (*e.g.*, project management, engineering, investment delivery, etc.) have specific budgetary goals that are incorporated into their performance evaluations. Performance is measured monthly to ensure adherence to these goals and to address variances. This metric is aimed at developing accurate budgets and managing to the budgeted levels.

Q. WHAT ARE THE "ROUTINE" PROJECT TYPES YOU MENTIONED EARLIER?

A. Routines or blankets are budgets used to fund routine small projects that are typically less than $300,000. The Company has three Routine budgets in base rates: Asset Health (Reliability), New Business, and Capacity (Reliability).

Q. CAN YOU DESCRIBE HOW THE COMPANY BUDGETS FOR ROUTINES?

A. Yes. Because the routine projects are generally not defined until the current year, the budget is determined based largely on historical actuals in each budget grouping, such as for new business growth, reinforcements, or relocations. More specifically, routine budgets are primarily based on a two-year historical average (2023 and 2024 actuals) by budget category, plus corporate escalation (inflation) factors. This routine grouping of projects serves to allocate funding for performing core business functions, such as connecting new customers, reconstructing facilities, and purchasing new meters, regulators, and material.

Q. WHAT ARE DISCRETE PROJECTS?

A. Discrete projects are typically large multi-month projects, greater than $300,000, in which the Company sets up a discrete work order to track the specific cost of the project. Discrete projects in base rates are identified through the

Company's Builders Call Line (for new business) or through the Company's planning process (reliability and safety). Discrete projects in reliability and safety are identified based on the system risks from sources such as operations, gas engineering, and integrated system planning. These projects could include tools needed to maintain the system, replacement of assets due to obsolescence, or reinforcement of pipelines due to system load growth, among others.

Q. HOW DOES THE COMPANY BUDGET FOR DISCRETE PROJECTS?

A. As mentioned earlier, discrete projects are typically multi-year projects greater than $300,000. During the Company's annual budget cycle, we follow a rigorous budgeting process that identifies the optimal mix of projects and expenditures for a given year. If a discrete multi-year project is known and of high enough priority to be included in the annual budget, it is added to the budget during the regular budget cycle.

Q. IN GENERAL, HOW DOES THE COMPANY DETERMINE COST ESTIMATES FOR INDIVIDUAL DISCRETE PROJECTS?

A. Given the nature of our business, the Company must estimate the costs of large multi-year projects that contain unknown variables that may impact the final cost of the project. The project development process is a tiered approach with prescribed planning requirements at each gate within a project's lifecycle. This requires project managers to develop a registry of project risks including material availability, contractor resourcing strategy, operational schedules, and public impact. To the extent a budget contains a level of contingency to account for unanticipated variables to minimize the impacts of the overall budget, such contingencies are refined as a project goes through the process.

Finally, once a project is under way, the project manager meets regularly with key staff (*i.e.*, siting and land rights, sourcing, construction/operations, etc.) where issues and concerns are identified, and solutions are developed. The overall goal is to achieve safe and timely completion of the project at no more than the budgeted cost.

C. Gas Operations Budgeting Trends

1. Gas Operations' Recent Capital Investment Trends

Q. PLEASE SUMMARIZE THE CAPITAL ADDITIONS IN SAFETY, RELIABILITY, NEW BUSINESS THAT ARE INCLUDED IN THIS RATE CASE.

A. Table 1 below summarizes the Company's capital additions in these three areas included in the 2026 test year, 2025 forecasted additions, and a three-year trend of capital additions from 2022 to 2024 (the most recent three years of actual data).

Table 1
Gas Operations Capital Additions 2022-2026
State of Minnesota Gas Jurisdiction ($ millions)

MN Gas Additions	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 Test Year
Safety	$1.8	$2.4	$3.9	$4.0	$8.2
Reliability	$27.7	$33.7	$50.7	$41.2	$29.8
New Business	$37.3	$37.8	$26.6	$33.3	$32.3
Total	**$66.8**	**$73.9**	**$81.2**	**$78.5**	**$70.3**

Q. WHAT WERE THE PRIMARY DRIVERS OF GAS OPERATIONS' CAPITAL ADDITIONS FROM 2022 THROUGH 2024?

A. Most of the Gas Operations capital additions from 2022 through 2024 are for routine investments in reliability asset renewals and new customer connections, as well as continued progress in the Meter Module program, as previously discussed in the Company's 2024 Gas Rate Case. In addition, several large discrete reliability projects were completed during this timeframe. Projects completed in 2022 include a project in support of additional capacity in the Delano area for $11.7 million and a reinforcement in the Sartell area for $4.5 million. Projects completed in 2023 include a reinforcement project in the Woodbury area for $1.7 million and replacement of a line heater at Mendota Station for $1.0 million. Projects completed in 2024 include a New Business project in the Cottage Grove area for $2.5 million and Reliability projects including a regulator station rebuild for $1.1 million, and an East Saint Cloud area station and odorizer project for $1.0 million. In addition, a discrete new business project in support of new service to the Sherco Generating Station to provide gas supply to the plant's auxiliary boiler was completed in 2022 for $5.1 million. Reliability routines also had $21.6 million in total for various reinforcement projects during the period 2022-2024. New business capital additions were $10.7 million lower in 2024 compared to 2022 primarily due to lower meter purchase activity in 2024.

Q. WHAT ARE THE PRIMARY DRIVERS OF GAS OPERATIONS' CAPITAL ADDITIONS FORECASTED FOR 2025?

A. The 2025 forecasted capital additions are estimated at $78.5 million, an increase compared to 2022 and 2023, but a reduction compared to 2024, which illustrates the variability of investments to meet system needs from year to year. As in 2022-2024, most of the investments in 2025 are for routine projects in reliability asset renewals and new customer connections, as well as completion of the Meter Module program, which concludes in 2025. Although investments are not as high in 2025 as 2024, the primary driver for the increase in capital additions in 2025 compared to 2022 and 2023 are discrete reliability investments. Larger discrete reliability projects in 2025 included the Forest Street Bridge Crossing renewal in Saint Paul for $3.3 million and the 3rd Street N. main renewal in Saint Cloud for $2.7 million. Also contributing to this increase was an overall increase in the number of discrete reliability projects of approximately 10 percent in 2025 compared to 2023.

Q. WHAT DOES TABLE 1 INDICATE REGARDING GAS OPERATIONS' CAPITAL INVESTMENT TRENDS?

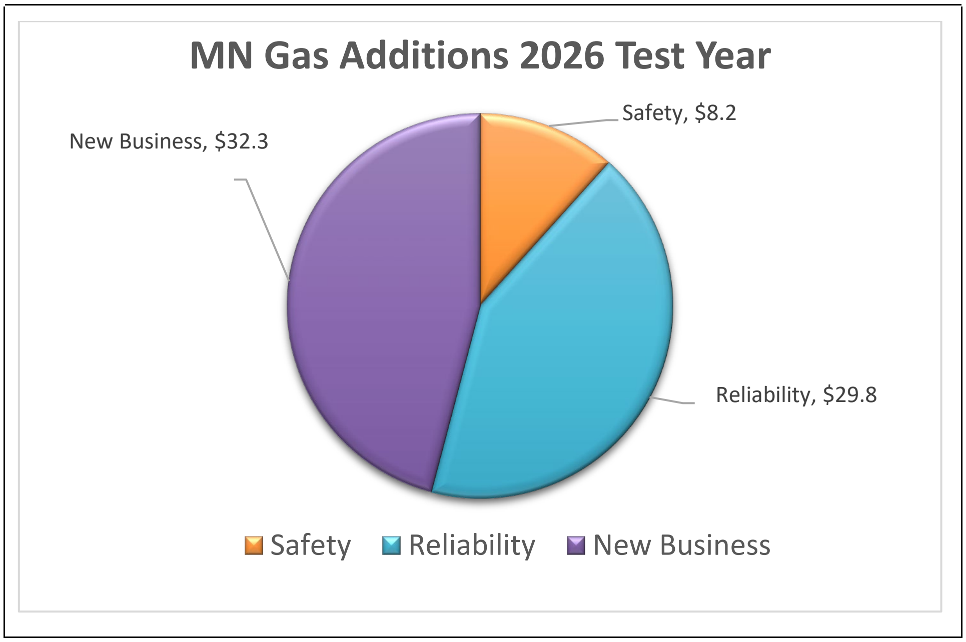
A. Table 1 illustrates that capital investments can vary significantly on a year-to-year basis depending on the specific work that is necessary to meet the needs of both our customers and our business. In certain years, Gas Operations' capital additions may be lower for a variety of reasons, including the level of customer new business requests or fewer large infrastructure projects. At the same time, Gas Operations' capital investment levels may increase in years when we are working on major initiatives, and capital additions necessarily increase when those initiatives are placed in service. For example, larger investments in 2024, primarily related to discrete reliability projects as described above, reflect capital additions for specific initiatives being placed in service in that year.

2. *Overview of Gas Operations' 2026 Capital Investments*

Q. WHAT ARE GAS OPERATIONS' CAPITAL FORECASTS FOR 2026 BY CAPITAL BUDGET GROUPING?

A. In addition to Table 1 above, Figure 2 below illustrates the Company's forecasted Gas Operations capital additions in the 2026 test year.

Figure 2
Gas Operations 2026 Capital Additions ($ millions)



Q. HOW DO GAS OPERATIONS' CAPITAL ADDITIONS FOR THE 2026 TEST YEAR COMPARE TO HISTORICAL TRENDS?

A. Capital additions for 2026 are estimated at $70.3 million, which is 10 percent lower than the 2025 forecast. While investments in the Safety category in 2026 are higher than prior years, this increase is more than offset by lower overall investment in the Reliability category compared to each year 2023-2025, primarily related to a decrease in discrete reliability investments in 2026, as described above. The drivers of the increase in the Safety category in 2026 are investment in discrete safety projects that I will discuss further below.

Q. WHAT ARE THE MAJOR CAPITAL INVESTMENTS IN THE COMPANY'S 2026 TEST YEAR?

A. The major capital investments in 2026 include a reinforcement project to address inlet pressure for the R400 regulator station, advanced mobile leak detection (AMLD) unit purchases, End-of-Life Remote Terminal Unit (RTU) program replacements, and the continuation of our Inside Meter Move Out program. These individual projects and the associated capital additions for each are summarized in Table 2 below.

Table 2
Gas Operations Major Capital Projects 2026
State of Minnesota Gas Jurisdiction ($ millions)

Capital Category	Project Name	2026 Test Year
Reliability	R400 Inlet Reinforcement Phase 1	$18.7
Safety	Inside Meter Move Out	$4.3
Safety	AMLD Unit Purchases	$2.1
Reliability	End-of-Life RTU Replacement	$1.7

I will discuss these additions, as well as our overall test year budgets, in more detail in the next section of my Direct Testimony.

D. Capital Additions for 2026

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

A. The purpose of this section is to provide more detail regarding the capital additions for discrete and routine projects for Gas Operations during the 2026 test year. For purposes of testimony, we provide detail for well over 80 percent of the capital additions being placed in service in 2026. Unless otherwise stated, all capital dollar figures are at the State of Minnesota Gas jurisdictional level. The capital amounts are also included in Exhibit___(AEB-1), Schedule 3.

1. *Reliability of the Gas System*

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE RELIABILITY CATEGORY?

A. Table 3 below identifies the 2026 reliability capital costs, split between routine and discrete projects, to be incurred by the Company and proposed for inclusion in base rates. These investments are necessary because the Company has an obligation to provide reliable service to our customers. Table 3 also includes the split between routine and discrete reliability projects for 2022-2024, and for the 2025 forecast.

Table 3
Gas Operations Reliability Capital Additions 2022-2026
Routines vs. Discrete Projects
State of Minnesota Gas Jurisdiction ($ millions)

Project Name	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 Test Year
Routine	$6.7	$7.0	$7.9	$7.3	$9.3
Discrete	$20.9	$26.7	$42.8	$32.2	$20.5
Total	**$27.7**	**$33.7**	**$50.7**	**$39.5**	**$29.8**

Q. PLEASE DESCRIBE THE DISCRETE RELIABILITY PROJECTS THAT WILL BE IMPLEMENTED IN 2026.

A. Table 4 below lists the key discrete reliability projects that will be in-serviced in 2026. In addition, Table 4 contains a brief description of each reliability project over $1 million, and these projects will be described in further detail in separate sections below. As shown, the majority of investment in the discrete reliability category in 2026 is in the R400 Inlet Reinforcement Phase 1 project, which will be discussed in detail below.

Table 4
Discrete Reliability Plant Additions 2026
State of Minnesota Gas Jurisdiction ($ millions)

Project Name	Description	2026 Test Year
R400 Inlet Reinforcement Phase 1	Replace approximately 2.26 miles of 8-inch HP steel pipeline along Highway 96 and Old U.S. Highway 8 in Ramsey County, Minnesota with 20-in HP steel pipeline. This project is needed to increase capacity on the Highway 96 pipeline to address inlet pressure at the R400 regulator station.	$18.7
End-of-Life RTU Replacements	Programmatic replacement of RTUs at the end of useful lives. The new RTUs also provide enhanced cyber security protocols.	$1.7
Reliability – Other	Various projects in support of system reliability.	$0.2
Total		**$20.5**

Q. HOW DOES THE COMPANY IDENTIFY RELIABILITY PROJECTS THAT ARE NEEDED ON THE SYSTEM?

A. Maintaining a reliable system requires that the Company proactively assess the capacity needs of the system and respond when a capacity need is identified. Reliability projects, such as the projects listed in Table 4 above, are identified as a result of the Company's annual long-term planning process. The Company's long-term planning process is described further below.

Q. HOW IS THE COMPANY'S SYSTEM LONG TERM PLANNING PERFORMED?

A. Through the use of GIS data, Supervisory Control and Data Acquisition (SCADA) data, Customer Billing data, and user input information, the Company creates representative system models with the Synergi® Gas hydraulic modeling software. These models are capable of simulating gas system performance under specific weather conditions. For the purposes of long-term planning, these models are run under design day peak hour conditions, discussed further below. The Company uses the results of these models to identify locations within a system where the pressure is below the minimum required system pressure, indicating a capacity shortfall at that area. Additionally, the models are also paired with forecasted firm customer growth rates and known capacity checks to determine the impact on system pressures over the next five years, allowing the Company to identify future capacity shortfalls. Once a capacity shortfall is identified, a project is scoped to solve the capacity shortfall. This project is scoped so that it completely alleviates the capacity shortfall through ten years beyond the first year of the long-term planning cycle.

Q. IS THE COMPANY'S SYSTEM PEAK DAY TEMPERATURE METHODOLOGY IN ALIGNMENT WITH OTHER GAS UTILITIES ACROSS THE U.S.?

A. Yes. The Company uses the industry standard probabilistic modeling approach based on historical weather data to determine the coincidence of a 1-in-30-year cold weather event (*i.e.*, peak day) occurring in each operational areas on the Company's system. A "1-in-30" event is based on the likelihood of the extreme weather event that will occur within 30 years of weather occurrence. The peak hour analysis, which is a subset of the peak day, is used for the NSPM system modeling. The peak hour load forecast is the goal for system design planning that must be met by the capacity of the Company's piping network.

Q. WHAT ARE THE 1-IN-30 PEAK HOUR TEMPERATURES FOR EACH REGION IN THE COMPANY'S SYSTEM?

A. Table 5 below provides the peak hour temperatures by operational area that are likely to occur once every 30 years on the Company's gas system. The Company designs its natural gas system to serve firm customers at these peak hour temperatures. The operational areas listed below include Company service territories within Minnesota.

Table 5
Peak Hour Temperatures by Operational Area

Operational Area	Peak Hour
Brainerd	-48°F
Delano	-35°F
East Grand Forks	-40°F
Faribault	-37°F
Moorhead	-37°F
Saint Cloud	-41°F
Saint Paul	-33°F
Winona	-36°F

Q. HAVE RECENT COLD WEATHER EVENTS IMPACTED THE COMPANY'S SYSTEM MODELING AND PLANNED CAPACITY PROJECTS?

A. Yes. As described above, in the normal course of business, the Company reviews the operations of its gas system after each winter and based on system pressures and flow data combined with customer demand during cold weather, capacity projects are scoped to ensure reliable gas service to firm customers during peak hour temperatures.

Although the design day temperatures are recalculated annually, the peak hour temperatures were last modified after a severe cold weather event in the region in January 2019. These updated temperatures are reflected in Table 5 above and are factored into our current design day analyses. There have been no other significant cold weather events like January 2019, thus the revised peak hour temperatures, determined by the 1-in-30 methodology updated with latest years' temperatures, provided above continue to be used in the Company's modeling.

The peak hour temperatures, along with load growth projections and prior winter system performance are included in the engineering modeling to determine capacity needs, which drive the need for the discrete reliability projects discussed below.

a. R400 Inlet Reinforcement Phase 1 Project

Q. PLEASE DESCRIBE THE COMPANY'S GAS SYSTEM INVOLVED IN THE R400 INLET REINFORCEMENT PHASE 1 PROJECT.

A. A section of our high-pressure (HP)[3] distribution pipeline, consisting of 8-inch, 12-inch, and 16-inch steel segments, runs parallel to Highway 96 in Ramsey County, Minnesota, and was built in 1979-1980. It supports the North Metro intermediate pressure (IP) system by supplying two of its three regulator stations, including the R400 regulator station. This pipeline is critical for maintaining minimum regulator station inlet pressures essential for the North Metro IP system's operation and its ability to supply various distribution systems[4] serving our customers in the area. A map depicting the project area is provided in Exhibit___(AEB-1), Schedule 4 to my Direct Testimony.

Q. PLEASE DESCRIBE THE R400 INLET REINFORCEMENT PHASE 1 PROJECT.

A. As noted above, the R400 Inlet Reinforcement Phase 1 project is needed to address capacity on the Highway 96 HP pipeline, which serves the North Metro IP system. The Highway 96 HP pipeline is currently beyond capacity for design day peak hour conditions due to demand growth on the North Metro IP system that has occurred over time. Under design day conditions, the Highway 96 HP pipeline serves approximately 37 percent of the supply into the North Metro IP

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[3] Generally, high- and intermediate-pressure systems are greater than 60 pounds per square inch gauge (PSIG) MAOP.

[4] Generally, distribution systems are 60 PSIG or less.

system, serving existing customers in the communities of Shoreview, Arden Hills, New Brighton, and Roseville, Minnesota. This project will replace approximately 2.26 miles of 8-inch HP steel pipeline along Highway 96 and Old U.S. Highway 8 in Ramsey County, Minnesota with 20-inch HP steel pipeline. The new pipeline will tie into the inlet of regulator station R400 at the intersection of Old U.S. Highway 8 and 1st Avenue NW, and the existing 12-inch pipeline at Lexington Avenue and Highway 96. A map of the location and additional project information is provided in Schedule 4 to my Direct Testimony. This project is expected to have capital additions of approximately $18.7 million and is planned to be in-service in 2026.

Q. HOW DID THE COMPANY IDENTIFY THE NEED FOR THIS PROJECT?

A. The Company confirmed the need for this project during its long-term planning process for 2024. In prior years, low inlet pressures at regulator stations, driven by cold weather demand, were managed through field operating procedures. The Highway 96 HP pipeline cannot maintain minimum inlet pressures at the R400 regulator station during design day conditions, indicating a capacity shortfall. Forecasted demand growth in Minnesota suggests this shortfall will continue to increase over time. This project, designated as "Phase 1," is one of three projects planned to be completed over the next ten years to reinforce the capacity requirements of the North Metro IP system, including forecasted future growth in the area. Based on system modeling results, the Company has planned a phased approach to address the capacity requirements of the North Metro IP system. The R400 Inlet Reinforcement Phase 1 project will be implemented in 2026 to address a current capacity shortfall and maintain minimum inlet pressure requirements at the R400 regulator station during design day peak hours. The other two projects will be implemented over the next ten years both to serve current customers and to address future demand growth in the area.

Q. WHAT IS THE RISK OF NOT MEETING THE IDENTIFIED CAPACITY NEED?

A. The hydraulic model shows insufficient inlet pressures to the R400 regulator station supplying the North Metro IP system that would impact service reliability to firm customers at the design day temperature. Such issues can also affect customers at temperatures above design day, depending on other factors affecting system pressure. For example, failure to maintain inlet pressures at critical facilities, such as regulator stations, can impact a station's ability to hold its setpoint, which would impact the normal operation of the facility and reduce delivery pressures to customer meters downstream of the regulator station that can result in loss of service to customers during the coldest times of the year. The size of the capacity shortfall at the inlet of the R400 regulator station is equivalent to approximately 3,750 residential customers and will grow over time as additional growth in the area occurs.

Q. WHAT ALTERNATIVES TO THIS PROJECT DID THE COMPANY CONSIDER?

A. The Company evaluated various options for pipeline installation to provide the necessary system capacity for this area. For example, the Company evaluated installation of approximately eight miles of new pipeline from Ash Street and Centerville Road (in an existing ROW) to tie in at the inlet of regulator station R502 near Long Lake Road and Greenwood Drive, including a new regulator station. The Company also evaluated deployment of compressed natural gas (CNG) facilities at the R400 regulator station.

Q. WHY DID THE COMPANY NOT SELECT THE ALTERNATIVE TO INSTALL EIGHT MILES OF NEW PIPELINE ALONG THE ROUTE IDENTIFIED ABOVE?

A. Installing eight miles of new pipeline to tie in at the inlet of regulator station R502 near Long Lake Road and Greenwood Drive, which would also include installation of a new regulator station, is expected to be significantly more expensive than the proposed R400 project due to the longer length and additional equipment necessary for the project. The Company also evaluated other alternatives to meet the capacity requirements for the North Metro IP system. These alternatives were not selected based on cost considerations and system requirements, including having higher capital costs, having higher annual O&M costs, requiring a change in asset type classification, and/or not meeting the growth model scenarios, which are factored into the Company's long-term system planning as described in Section III.D.1 above.

Q. WHY DID THE COMPANY NOT SELECT THE ALTERNATIVE TO DEPLOY CNG FACILITIES AT THE R400 REGULATOR STATION?

A. While the Company considered supplementing the system with CNG, this alternative would require a CNG skid and multiple CNG semi-tankers along with siting and permitting. Additionally, supplemental CNG would be injected at an increasingly frequent number of times throughout the year. As the injection frequency increases, so does the number of times the CNG semi-tankers would require refueling by transporting large CNG trailers into and out of this metro area location. This alternative also presents challenges related to siting CNG at this location, based on limited land available, the time it would take to identify and obtain the necessary permits for a CNG site, and on-going security requirements. For this project, CNG is not an effective solution due to the significant and ongoing challenges with implementation and operations.

Q. PLEASE DESCRIBE THE PLANNING AND EXPECTED SCHEDULE FOR THIS PROJECT.

A. Once the project was identified, the Company prepared cost estimates based on vendor unit pricing, historical costs of similar projects, available material costs, and expected costs per foot, given the specific location and installation method, including contingencies and subject to degrees of accuracy tied to the Company's budgeting processes. Conceptual design began in March 2025, and detailed engineering will begin in October 2025. Project construction is expected to begin in the second quarter of 2026, and the project is expected to be placed in-service in the fourth quarter of 2026.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE PROJECT?

A. This project will retire approximately 2.26 miles of 8-inch steel pipe and install approximately 2.26 miles of 20-inch steel pipe. Although detailed design has not begun, a preliminary review estimates approximately 5000 feet of the length will be installed using horizontal directional drilling (HDD), and approximately 7000 feet will be installed using an open trench method. The retired 8-inch steel pipe will be retired in accordance with permitting agency requirements, including sealing and retiring the existing pipeline in place and physical removal of the existing pipeline where required. This project will be installed in the existing right of way. Additional work for this project will involve replacing two regulator station inlet fire valves and four mainline isolation valves along the route. Significant traffic control and restoration is anticipated and will be executed in accordance with permitting agency requirements.

Q. HOW WILL THE WORK ON THE R400 INLET REINFORCEMENT PHASE 1 PROJECT PROCEED?

A. The Company has completed conceptual design to the extent necessary to develop a preliminary project cost estimate and to review the project with permitting parties. The project will begin detailed engineering in October 2025. As detailed engineering advances, the construction vendor will be secured and material procurement and permitting will commence with completion estimated in the first quarter of 2026. Construction is anticipated to begin in the second quarter of 2026, with construction, commissioning, and restoration anticipated to be completed in the fourth quarter of 2026.

Q. HOW WILL THE PROJECT BE MANAGED TO ENSURE COMPLETION AT A REASONABLE COST?

A. Consistent with Gas Operations project management processes, this project will be subject to multiple scope, schedule, and estimate reviews to ensure successful project completion. Once the project is underway, the project manager will meet regularly with key staff (*i.e.*, sourcing, construction/operations, engineering, etc.) to identify issues and concerns and develop solutions. The overall goal is to achieve safe and timely completion of the project scope at no more than the budgeted cost.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR THE R400 INLET REINFORCEMENT PHASE 1 PROJECT?

A. The budget was developed based on estimating previously described, with planning and design beginning in 2025. In 2026, planning and design will continue along with the permitting and construction to in-service the project in

2026. The total cost estimate for the project is approximately $18.7 million. A breakdown the project costs by cost category is provided in Table 6 able below.

Table 6
R400 Inlet Reinforcement Phase 1 Project
Project Costs by Category ($ in millions)

Cost Category	Cost
Engineering & Administration	$2.5
ROW Acquisition & Permitting	$0.3
Materials	$2.4
Mechanical Construction	$9.7
Ancillary Construction	$3.8
Current Total Project Estimate	$18.7

Q. PLEASE SUMMARIZE HOW THIS PROJECT WILL BENEFIT CUSTOMERS.

A. The R400 Inlet Reinforcement Phase 1 project will increase capacity on the Highway 96 HP pipeline, which supplies approximately 37 percent of the North Metro IP system. That system is currently over capacity during design day peak hours due to sustained demand growth that has occurred over time. This project will help ensure reliable service for existing customers in Shoreview, Arden Hills, New Brighton, and Roseville, while also supporting future forecasted growth in the area, with greater feasibility and at a lower anticipated cost than available alternatives.

b. End-of-Life RTU Replacements

Q. WHAT IS THE END-OF-LIFE RTU PROJECT?

A. The End-of-Life ("EOL") RTU project is a programmatic replacement of RTUs across the Company's Minnesota service territory. The RTUs function as a critical piece of the communication system between assets in the field and the Gas SCADA system used for system monitoring and control.

Q. WHY IS THIS PROJECT NEEDED?

A. The project is needed in order to systematically replace RTUs that are nearing end of life. The new units will also have more enhanced cyber security protocols which can provide less risk for the Gas SCADA system.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE PROJECT?

A. In 2026, the program is expected to replace approximately 12 units at an average cost of approximately $140,000 per unit. There will be ongoing work to replace all of the RTUs beyond 2026 as well.

c. Reliability – Other

Q. PLEASE DESCRIBE THE RELIABILITY – OTHER PROJECTS.

A. In addition to the discrete reliability projects discussed above, the Company will also perform other projects to help ensure system infrastructure reliability to serve Minnesota customers. These planned projects in 2026, totaling approximately $0.2 million, include replacements of ERX devices, and Geospatial Information Systems (GIS) conflation data projects. The ERX devices are critical components used to monitor and record pressure within the gas distribution system. Many existing units are reaching end-of-life and require replacement to maintain system integrity and compliance. In 2026, the Company plans to replace obsolete ERX units with upgraded models, which offer enhanced performance and meet current cyber security standards. These replacements will also include upgrades to cell-based communication capabilities, improving data transmission reliability and reducing latency. The Geospatial Information Systems (GIS) Conflation Project will improve the spatial accuracy of mapping data by aligning asset data with updated parcel boundaries. This process ensures that infrastructure such mains and services are correctly represented in our mapping system.

Q. DOES THE COMPANY REVIEW ITS PLANNED RELIABILITY PROJECTS ON A REGULAR BASIS?

A. Yes. As discussed above, the Company reviews the operations of its gas system each year using modeling that reflects updated system configurations, customer demand, and the system performance during the prior winter heating season. Capacity projects are scoped to ensure reliable gas service to firm customers during design hour temperatures. This assessment also allows the Company to review reliability projects that have already been planned to verify the need for as well as the scope and timing of projects already identified or can result in identification of new projects that may be needed in the near term.

d. Routine Reliability Projects

Q. PLEASE DESCRIBE THE INVESTMENTS IN ROUTINE RELIABILITY OF APPROXIMATELY $9.3 MILLION THAT THE COMPANY ANTICIPATES IN 2026.

A. There are several items that are included in the reliability routines for 2026, and the costs in 2026 are primarily related to two types of work. First, the reliability routine budget will fund emerging main and/or service replacements, leak repairs, removal of service due to structure removal, replacement/removal of services in support of main reinforcements or main relocations, and customer-requested relocation of service due to building modifications. Second, the reliability routine budget will fund infrastructure work related to increasing gas main capacity to mitigate low-pressure, customer-outage related risks based on design day modeling driven by increased load from either existing or new firm customers.

Q. HOW IS THE TEST YEAR BUDGET DEVELOPED FOR ROUTINE RELIABILITY ADDITIONS?

A. The budget is determined primarily based on a two-year historical average (2023 and 2024 actuals) plus corporate escalation (inflation) factors.

Q. WHY IS THE 2026 FORECAST HIGHER THAN PRIOR YEAR ACTUALS?

A. The 2026 routine reliability budget reflects undefined emergent work to support reliability projects typically under $300,000. While the type of work is known going into the year, the specific scope and timing of this repeatable activity is often undefined. As we move through the year, and specific projects are identified, some spending will shift to a discrete structure if the estimate exceeds the $300,000 guideline, thereby reducing routine actuals as compared to the forecast. This is reflected in Table 3 above. In short, the total work to support reliability is the same, but some of the work will shift categories, from being categorized as routine in the budget to being categorized as discrete in actuals.

Q. WHY IS THE BUDGET FOR RELIABILITY ROUTINES FOR THE TEST YEAR REASONABLE?

A. First, the work to maintain asset health and capacity is necessary to the reliability of NSPM gas system. Second, the budget levels for the test year are prudent. As referenced previously, reliability capacity routines are impacted by new business demand due to service and infrastructure work that support new business activities, as well as by increased capacity needs.

2. Safety of the Gas System

Q. PLEASE PROVIDE AN OVERVIEW OF THE SAFETY CAPITAL ADDITIONS INCLUDED IN THIS RATE CASE, BETWEEN ROUTINE AND DISCRETE PROJECTS.

A. While many of our capital investments in safety remain in the GUIC Rider, the Company must also make investments in its system that are not recoverable under the GUIC Rider. These investments are necessary because the Company has an obligation and works to ensure the safe delivery of natural gas to our customers. This is important considering incidents that have occurred in other areas of the country and the need to comply with PHMSA requirement that I discussed earlier in my testimony. Table 7 below identifies the Safety additions that the Company will invest in by category, outside of the GUIC Rider. All capital safety projects are discrete projects – there are no routine safety projects.

Table 7
Discrete Safety Capital Additions 2022-2026
State of Minnesota Gas Jurisdiction ($ millions)

Project Name	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 Test Year
Inside Meter Move Out	$0.1	$0.4	$0.7	$1.7	$4.3
AMLD Unit Purchases	$0.0	$0.0	$0.0	$0.0	$2.1
Tools and Equipment	$1.3	$1.5	$2.1	$3.9	$1.1
Capitalized Locating Costs - Gas	$0.5	$0.5	$1.0	$0.1	$0.6
Total	**$1.8**	**$2.4**	**$3.9**	**$5.7**	**$8.2**

a. Inside Meter Move Out

Q. WHAT IS THE INSIDE METER MOVE OUT PROGRAM?

A. Through the Inside Meter Move Out (IMMO) program, NSPM is moving a portion of our gas meters still located inside of customer premises to outside locations and replacing the existing facilities with new meters, connections, and regulators. The relocation of meters outside of a customer's premises 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 potential ignition.

Q. WAS THIS PROGRAM IDENTIFIED IN PRIOR GAS RATE CASES?

A. Yes. The IMMO program was introduced in our 2022 Gas Rate Case (Docket No. E002/GR-21-678), and initial work on the project began in 2022. The program was also discussed in the 2024 Gas Rate Case as project implementation continued. This program is expected to be completed in 2028. I discuss the program and provide details about the project schedule and costs below.

Q. HOW OFTEN IS NSPM REQUIRED TO INSPECT METERS?

A. The requirements regarding the inspection of meters are set forth in the Code of Federal Regulations (CFR). Pursuant to 49 CFR Part 192.723(b)(2), NSPM is required to conduct leak surveys once every five years at intervals not exceeding 63 months for facilities outside of business districts. Pursuant to 49 CFR Part 192.723(b)(1), facilities within business districts must be surveyed at intervals not to exceed every 15 months, but at least once each calendar year.

Further, pursuant to 49 CFR Part 192.481(a), NSPM is required to conduct atmospheric corrosion inspections once every three years at intervals not exceeding 39 months.

Q. WHAT ARE LEAK SURVEYS AND ATMOSPHERIC CORROSION INSPECTIONS?

A. A leak survey is a systematic method to locate leaks in a gas piping system. Atmospheric corrosion inspections inspect all above-ground piping and assets that are exposed to the atmosphere. Facilities are inspected for coating damage and are evaluated to determine the areas and extent of atmospheric corrosion.

Q. WHY ARE THE LEAK SURVEYS AND ATMOSPHERIC CORROSION INSPECTIONS IMPORTANT?

A. Regular leak surveys and atmospheric corrosion inspections on meters and services are required to prevent and/or detect gas leaks, which if not addressed, could result in personal injury and/or property damage. Thus, it is important to have access to customer meters to conduct these surveys and inspections to ensure not only the safety and integrity of our gas system, but the safety of our customers.

Q. GENERALLY, DO INDUSTRY REGULATIONS SPECIFY THE LOCATION OF METERS ON CUSTOMER PREMISES?

A. Yes. The current Code of Federal Regulations (specifically, 49 CFR Part 192.353) permits inside meters on customer premises; however, each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location. In addition, the Uniform Plumbing Code (UPC) and the National Fuel Gas Code (NFPA 54) both require that gas meters be located in ventilated spaces that are readily accessible for examination, reading, replacement, or necessary maintenance. The preferred industry practice is to have meters located on the outside of buildings.

Q. CAN YOU ELABORATE FURTHER ON WHY NSPM PREFERS TO LOCATE METERS OUTSIDE THE CUSTOMER'S PREMISES?

A. Yes. NSPM prefers to locate meters outside the customer's premises for three reasons: cost, customer convenience, and customer safety. Inside meters, especially for locations outside of business districts, often present a challenge in completing the required leak surveys, atmospheric corrosion inspections, and maintenance because they cannot be easily accessed. Meters inside the business districts are generally more accessible than residential meters due to the nature of business hours and the availability of people to grant on-site access. In the case of the meters located inside residential homes, NSPM has to make arrangements with customers in order to access the equipment to perform the required inspections or maintenance. This is inconvenient for our customers and inefficient for NSPM's operations, as it may result in multiple trips to customer locations. Additionally, it is harder for Xcel Energy personnel to access the homes of customers who temporarily relocate during the winter months, leaving the house vacant. It also requires our personnel to enter the customer home, which may not be comfortable for them.

Additionally, if a leak occurs on a meter set located inside a customer's basement, there is a higher likelihood of gas accumulating inside the structure where there are more sources of ignition, such as a customer's furnace, water heater, dryer, or electrical switches. By moving inside meters outside, it reduces the inherent risks of an inside gas leak and improves customer safety. It also provides Xcel Energy crews a safer method to isolate the gas (turn off) at the meter in emergency situations if it is located outside.

Q. HOW MANY METERS IN THE COMPANY'S MINNESOTA SERVICE TERRITORY ARE LOCATED INSIDE CUSTOMER PREMISES?

A. Currently, there are approximately 20,000 meters located inside customers' premises both within and outside of business districts.

Q. ARE THERE REASONS WHY SOME METERS SHOULD REMAIN LOCATED INSIDE A CUSTOMER'S PREMISES?

A. Yes. There are situations where the preferred meter location for NSPM and the customer is inside. An apartment complex, for example, may have dozens of meters in a special section of the building that is protected from vehicle traffic and is specifically built to house meters. Some meters may remain inside of customer locations due to space constraints and design – primarily in commercial settings.

Q. WHAT IS THE STATUS OF NSPM'S PLAN FOR INSIDE METERS UNDER THIS PROGRAM?

A. The Company began the Inside Meter Move Out project Minnesota in 2022. The project will move approximately 6,400 meters and connections that are currently located inside of customer premises and that can be moved to outside locations. Using a combination of internal and contract resources, NSPM will replace the old meters and connections with new meters, connections, and regulators with over-pressure protection and relief. Further, in many instances, the service line from the main to the meter will also be replaced, as the service lines are of older materials that carry a risk of failure under DIMP. In a manner consistent with our DIMP, NSPM will base the determination as to whether a service line will be replaced on its age, condition, and material type.

Q. HOW LONG WILL IT TAKE TO COMPLETE THE INSIDE METER MOVE OUT PROJECT?

A. The project is expected to be completed in 2028. As noted above, NSPM began relocating meters to the outside in 2022. In 2023, the Company renewed and replaced 76 meters, and in 2024 completed 143 meters that were moved out. The Company anticipates completion of approximately 300 meters moved out in 2025, and approximately 600 meters in 2026. Particularly during 2022, the first year of implementation, global supply chain issues impacted delivery of various materials, which in turn has impacted the Company's ability to relocate meters according to initial project plans. Due to these ongoing supply chain issues, the Company revised its forecasts for the number of meters to be moved in 2025 and 2026 to reflect current expectations for implementation. The project team continues to work with the manufacturers to align demand.

Q. WHAT ARE THE FORECASTED CAPITAL ADDITIONS FOR THIS PROJECT?

A. The program is forecasted to have $1.7 million in capital additions in 2025 and $4.3 million in 2026. The estimated capital cost associated with relocating a meter outside is approximately $7,150 comprised of an estimated $6,600 when a service renewal is required and $550 estimated for the meter, regulator, and customer piping work. This includes the cost for materials and labor (*e.g.*, meters, service lines, regulators, labor, and restoration). This cost per meter replacement, multiplied by approximately 600 meters, equates to our 2026 capital expenditure budget of $4.3 million (excluding Allowance for Funds Used During Construction (AFUDC).

Q. WHAT DO YOU CONCLUDE REGARDING THE INSIDE METER MOVE OUT PROJECT?

A. The costs of this program should be approved, as the program reduces the risk of a catastrophic event from occurring due to a gas leak on an inside meter within a customer's premises, and the codes discussed above related to ventilation and accessibility of meters further support the need for this project. In addition, the development of a systematic, deliberate program to remove inside meters is a more cost-effective approach to maintain the meters. Inside meters cause accessibility issues when conducting leak surveys, inspections, outage relights, and normal maintenance. The program will streamline access to our assets and eliminate the need, time, and resources to coordinate access to inside meters. The project will also enhance customer service and the reliability of NSPM's gas system and bring the meter locations into conformance with industry standards. Finally, the related investment is prudent, reasonable in cost, and the assets will be used and useful in providing safe and reliable customer service.

b. AMLD Unit Purchases

Q. PLEASE GENERALLY DESCRIBE AMLD.

A. AMLD (Advanced Mobile Leak Detection) utilizes highly sensitive detection equipment which is mounted on a vehicle and detects methane and ethane passing through its path. AMLD technologies are used to detect methane leakage to help gas utilities identify and prioritize necessary repairs to help achieve emissions reductions related to the gas system. Compared to traditional methods, which require taking the detection device to the leak, primarily on foot, AMLD leak detection will allow the Company to cover a larger area with the same number of crews. This can allow the Company to prioritize repairs based on real-time data, reduce the time that a leak is active without detection, and ultimately increase the frequency of survey.

Q. WHAT AMLD COSTS ARE INCLUDED IN THE 2026 TEST YEAR?

A. The Company's proposed budget includes the costs of purchasing two AMLD units in 2026. The Company is expanding the program and ramping up its plans for use of AMLD in 2026. AMLD activities will include purchasing the two units, installing them in the appropriate vehicles, training the appropriate resources who will be driving the vehicles and collecting data, testing the equipment, and beginning "Super-Emitter Survey." Purchase of these two AMLD units will further support the Company's methane emissions reduction strategy, which is discussed in the Direct Testimony of Company witness Lyng.

Q. HAS THE COMPANY PREVIOUSLY PROVIDED INFORMATION TO THE COMMISSION ON AMLD?

A. Yes. On December 15, 2023, the Company filed its first Natural Gas Innovation Act (NGIA) Plan with the Commission. The NGIA Plan included a proposal for an AMLD pilot to assess AMLD technologies and demonstrate the emissions reductions that can be achieved through higher frequency leak surveys and through use of methane emissions data in prioritizing leak repairs. This was planned as the Company's first step to help the Company better understand the potential of AMLD combined with emissions quantification to achieve reductions in emissions and move the Company toward a net-zero gas distribution system. The costs associated with the AMLD pilot includes purchase of one AMLD unit and vehicle in 2026.

Q. IF THE COMPANY HAS AN AMLD PILOT PROGRAM APPROVED AND UNDERWAY, WITH COSTS TO BE RECOVERED UNDER THE NGIA RIDER, WHY IS THE COMPANY PLANNING TO PURCHASE TWO ADDITIONAL AMLD UNITS IN 2026 BEFORE THE CONCLUSION OF THE PILOT?

A. In the Company's pilot proposal filed on December 15, 2023, the Company indicated we would first survey the available technologies to determine the most suitable one for the Company. Since then, the Company has additional information available, partially resulting from an earlier pilot program in our Colorado service territory that began near the same time as the NGIA approval. Based on more recent information from our work in another jurisdiction, we have determined which technology is most suitable for use by the Company and expect similar results in Minnesota. The Company is expanding the program and ramping up its use of AMLD in 2026 because this will be an important component of the Company's strategy to reduce methane emissions from the system. The ramp up will allow the Company to work towards complying with Minnesota Statue 216H.02. Minnesota has established greenhouse gas (GHG) emissions reduction goals, including targets for natural gas emissions, through various legislative actions and frameworks like the Next Generation Energy Act and the Climate Action Framework. The state aims to reduce emissions by 50 percent by 2030 and achieve net-zero emissions by 2050. These goals are outlined in Minnesota Statute 216H.02, which sets specific reduction targets for all sectors, including those utilizing natural gas.

Q. ARE THERE OTHER BENEFITS OF AMLD, IN ADDITION TO REDUCING METHANE EMISSION?

A. Yes. While the primary objective of implementing AMLD is to reduce methane emissions from the Company's gas distribution system, AMLD is also anticipated to reduce operations and maintenance expenditures related to leak detection and abatement, especially as the Company further expands use of AMLD in the future and increases frequency of survey.

c. Tools and Equipment

Q. WHAT TYPES OF PROJECTS ARE PLANNED IN TOOLS AND EQUIPMENT?

A. The Company plans for tool and equipment replacements in future years in anticipation of replacing existing items due to damage, obsolescence, or other needs. In addition, the Company forecasts additions for programs of replacements. Tools and equipment purchases necessary for the safe and reliable operation of our system include items such as leak detection equipment, tapping tools, frost burning equipment, and various other items for emergency response, construction, maintenance, and repair. For 2026, the Company is forecasting $1.1 million in tools and equipment investments, which is consistent with amounts in recent years, and less than the 2023 forecast. This forecast is primarily based on historical spend plus escalation, in addition to specific tool initiatives that are relatively short in duration.

d. Locating Costs

Q. WHAT ARE CAPITALIZED LOCATE COSTS?

A. The Company has a Damage Prevention Program, through which we incur costs to identify and locate/mark where existing gas infrastructure exists underground in order to ensure that digging or construction work does not interfere with gas pipelines and create public safety risks. While most of our Damage Prevention costs are O&M, as I discuss later in my testimony, a portion of locate requests each year are performed for NSPM capital projects for new business, main renewals, and capacity projects. The costs for these locate requests are capitalized locate costs. In 2026, the Company forecasts incurring approximately $0.6 million of capitalized locate costs for the Minnesota gas jurisdiction, which is consistent with amounts the Company has incurred in recent years.

3. New Customer Business

Q. HOW DOES NSPM RECEIVE REQUESTS FOR NEW BUSINESS?

A. The Company receives requests from individuals and developers for new gas service through the Company's Builders Call Line. The Builders Call Line is the customer's first point of contact when requesting new gas and electric service from the Company and is intended to be a single-call department to simplify the customer's experience. The Company supports new business customers through five key phases of installing and connecting new service through the Builders Call line: (1) Application, (2) Design, (3) Payment, (4) Scheduling, and (5) Construction and meter set. The Builders Call Line delineates which tasks within the five phases are the customer's responsibility, the Company's responsibility, and joint responsibility between the customer and the Company.

Q. WHAT DOES NSPM DO UPON RECEIPT OF REQUESTS FOR SERVICE FROM NEW CUSTOMERS WITHIN THE COMPANY'S SERVICE TERRITORY?

A. The Company, as a general matter, will extend natural gas service to new customers under the rules of its tariff, subject to the availability of gas.

Q. HOW DOES NSPM DESIGN, ENGINEER, AND OBTAIN A COST ESTIMATE FOR A NEW BUSINESS PROJECT ONCE IT OBTAINS A REQUEST FROM THE CUSTOMER?

A. The design phase begins when a customer submits building plans and a request for service to the Company's Builders Call Line. Customers can submit applications online through Xcel Energy's Builders and Remodelers site, via a pdf application sent via email and phone. Information collected from customers includes address, customer contact information, building type and any available load information. That application is processed and is then assigned to a designer, who will contact the customer and arrange a meeting to cover any specifics related to the project.

After that initial meeting, the designer uses a program GE Design Manager to start outlining the project scale, route, and required materials to meet the customer's needs. GE Design Manager allows the designer to determine the pipeline route, select the required materials, and factor in installation and restoration costs. If the request for new gas service is large in nature, and served from our high-pressure system, the request for new business is transferred from the designer to a gas engineer. That list of materials and labor is then populated into the Company's Work and Asset Management (SAP) system and sent to local design and/or engineering management for review and approval before a quote is issued. From that point, the system-generated cost estimates are valid for 90 days before a refresh is required. If the customer accepts the quote by signing the service agreement, payment is collected, and the project is moved to construction.

Since GE Design Manager is built into the Company's GIS, all location and material information is captured and added to the Company's mapping system and serves as the Company's asset system of record. The design process is the same for both gas and electric, and a customer can start the process for both gas and electric services concurrently, with one application.

Q. HOW DOES THE COMPANY DETERMINE IF THE PARTY REQUESTING NEW SERVICE NEEDS TO BE CHARGED CONTRIBUTION IN AID OF CONSTRUCTION (CIAC)?

A. New business customers are subject to the Gas Extension Policy process as outlined in the Company's Service's Gas Tariff. That policy determines customer versus Company contributions to new gas line extensions.

Q. HOW ARE NEW BUSINESS PROJECTS ACCOUNTED FOR?

A. All costs associated with new business are capital, including labor and materials net of customer contributions. As with other parts of the Gas Operations projects, there are two types of capital project funding types: (1) discrete projects, and (2) routines. Discrete projects typically are more complex projects in excess of $300,000 that may include transmission mains, larger diameter distribution mains, regulator stations, and land or easement purchases. New business discrete projects are tracked individually under separate work orders and have a high likelihood of having expenditures in more than one budget year.

New business projects that are funded under routines are generally simpler in nature, like a new service or new meter, and not defined until the current year, because the Company will receive many requests for new service in any given year and therefore cannot necessarily predict the scope of requests received.

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE NEW BUSINESS CATEGORY FOR 2026?

A. As shown in Table 8 below, all new business plant additions in 2026 are classified as routines, totaling $32.3 million, as compared to total new business plant additions of $33.3 million in 2025, $26.6 million in 2024, $37.8 million in

2023, and $37.3 million in 2022. The reduction in 2024 routine plant additions was driven by $11.5 million in lower meter purchases compared to 2023.

Table 8
New Business Plant Additions 2022-2026
Routines vs. Discrete Projects
State of Minnesota Gas Jurisdiction ($ millions)

Project Name	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 Test Year
Routine	$30.9	$38.0	$23.8	$29.8	$32.3
Discrete	$6.4	($0.2)	$2.7	$3.5	$0.0
Total	**$37.3**	**$37.8**	**$26.6**	**$33.3**	**$32.3**

Q. HOW ARE CONSTRUCTION COSTS TYPICALLY DETERMINED FOR NEW BUSINESS WORK AT NSPM?

A. New business projects are primarily installed by qualified contractors where the Company has a negotiated Master Service Agreement (MSA) with each contractor. These MSAs have per-unit pricing. For example, within the negotiated MSA, the cost per service and the cost to install gas mains is set based on pipe diameter and the required installation technique (*e.g.*, trench, bore, etc.).

Q. WHAT METHODOLOGY DID NSPM USE TO FORECAST NEW BUSINESS ROUTINE ADDITIONS FOR THE TEST YEAR?

A. The 2026 test year new business routines forecast is based on the average of historical actuals from 2023 and 2024 escalated by the corporate inflation rates. These inflation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates.

Q. WHY IS THE NEW BUSINESS ROUTINE BUDGET FOR THE TEST YEAR REASONABLE?

A. As with the Company's other routine budgets, the work covered by these budgets is necessary to serve customers, and the budgeted amounts for the test year are reasonable. For the test year, the Company has budgeted $32.3 million in plant additions. From January 1, 2022 through December 31, 2024, the Company's actual plant additions for the new business routines averaged $33.9 million per year. The increase from 2024 to 2026 is reasonable because it is based on average of historical actuals from 2023 and 2024 (which incorporates the lower meter purchases in 2024), the 1.1 percent average annual total customer growth as referenced in the Direct Testimony Company witness Goodenough, as well as inflationary pressures impacting the costs to connect new customers.

IV. O&M BUDGET

A. O&M Overview and Trends

Q. WHAT IS INCLUDED IN THE COMPANY'S GAS OPERATIONS O&M BUDGET?

A. The Company incurs O&M expenses across various areas within Gas Operations, including the transmission and distribution business functions that are related to numerous activities that support the gas system. Federal and State codes require significant inspection and maintenance programs for gas utilities, the majority of which result in O&M expenditures. We must perform emergency response and Damage Prevention requests to locate our underground gas infrastructure to ensure public safety. Other types of O&M expense include internal labor, contract labor, materials, transportation, and other expenses. Portions of O&M are approved for recovery in the GUIC Rider and therefore are not part of our base rate request in this proceeding.

Q. WHAT ARE THE BASIC CATEGORIES OF GAS OPERATIONS' O&M BUDGET?

A. Gas Operations' O&M budget includes the following seven categories:

1. *Damage Prevention*: A program of O&M work that includes internal labor, contract labor, materials, etc. to perform locates of Company-owned underground gas infrastructure as required by state and federal agencies.
2. *Labor:* Internal labor (excluding damage prevention) to operate and maintain the Company's natural gas system.
3. *Outside Services:* Consulting and staff augmentation services to supplement internal labor to operate and maintain the company's natural gas system.
4. *Materials:* Costs related to consumables, hardware, and refurbished materials used in maintenance and repair operations, as well as tools and small equipment.
5. *Manufactured Gas Plant (MGP):* O&M costs associated with remediating former MGP sites.
6. *Transportation:* Costs of trucks, cars, and other fleet vehicles to transport our people and equipment as needed to provide gas service.
7. *Other:* Employee expenses, facility fees, and licenses.

Q. CAN YOU SUMMARIZE THE COMPANY'S BASE RATE O&M EXPENSE TRENDS IN RECENT YEARS?

A. Yes. Table 9 below summarizes the Company's base rate actual O&M expenses for 2022 through 2024, the 2025 forecast, and the budget for the 2026 test year. The O&M amounts by cost category are included in Exhibit___(AEB-1), Schedule 5, and the O&M amounts by FERC account are included in Exhibit___(AEB-1), Schedule 6.

Table 9
Gas Operations O&M Budget by Category 2022-2026
State of Minnesota Gas ($ millions)

O&M Categories	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 Test Year
Damage Prevention	$7.4	$8.0	$9.7	$10.2	$13.4
Labor	$19.3	$20.2	$22.1	$23.8	$26.5
Outside Services	$2.9	$3.1	$2.5	$2.2	$3.8
Materials	$4.5	$4.4	$5.8	$5.2	$4.4
MGP	($0.3)	$0.0	($0.2)	$0.3	$1.1
Transportation	$3.7	$3.2	$3.3	$3.5	$3.8
Other	($4.5)	($9.1)	($5.7)	($10.0)	($8.5)
Total	**$33.0**	**$29.9**	**$37.5**	**$35.3**	**$44.4**

Q. WHAT ANNUAL GUIC RIDER O&M EXPENSES WERE INCURRED FROM 2022 AND FORECASTED THROUGH 2026?

A. Table 10 below summarizes the Company's expenses that have been recovered through the GUIC Rider from 2022 to 2024 and forecasted in 2025 and 2026.

Table 10
GUIC Rider O&M 2022-2026
State of Minnesota Gas Jurisdiction ($ millions)

State of MN	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 Test Year
GUIC	$0.3	$0.7	$1.5	$2.3	$3.1

Q. PLEASE DESCRIBE THE OVERALL TRENDS FOR GAS OPERATIONS' O&M EXPENSES FOR 2022 THROUGH 2024.

A. Over the three years from 2022 to 2024, Gas Ops O&M costs increased, primarily related to damage prevention, labor cost increases, materials, and transportation. Damage prevention over the period increased primarily due to increases in outside services. Increases over this period related to materials and transportation costs were largely due to inflationary pressures. During this same timeframe, our GUIC O&M costs increased as certain projects were implemented.

Q. WHAT IS THE COMPANY'S GAS OPERATIONS O&M BUDGET FOR THE 2026 TEST YEAR?

A. The Gas Operations base rate O&M budget for the 2026 test year is $44.4 million as shown in Table 9 above. The basis for this budget is set forth in detail below.

Q. AT A HIGH LEVEL, WHAT ARE THE MAJOR COST DRIVERS OF THE 2026 GAS OPERATIONS O&M BUDGET?

A. Of the categories listed above there are three primary drivers of our 2026 Gas Operations O&M budget: (1) Damage Prevention; (2) Company Labor; and (3) Outside Services. I describe each of the budget categories and the reasons for anticipated cost increases later in my testimony.

Q. CAN YOU PROVIDE MORE DETAIL EXPLAINING WHY THESE ARE THE DRIVERS OF THE 2026 O&M INCREASES COMPARED TO PRIOR YEARS?

A. Yes. As shown in Table 9 above, the 2026 Gas Operations non-GUIC O&M budget has increased as compared to the 2024 actual O&M costs. These increases are driven by the three factors I noted above.

First, the Company's O&M costs for Damage Prevention (mandated locates for gas facilities through the Gopher State One Call program) are increasing significantly, due to efforts to improve the accuracy and other metrics associated with our Damage Prevention Program, as well as increasing outside services costs, which reflects both higher anticipated costs for vendor services, as well as an increase in the forecasted number and complexity of locate requests.

Second, the Company's labor costs are increasing for the test year due to bargaining unit contract increases, and a shift in work to O&M. Specifically, with our meter module replacement capital project coming to an end, we expect that our employees' work will shift more heavily to system operations and maintenance work. I describe the Company's test year labor costs in more detail later in my testimony.

Third, the budget for outside services is increasing due mainly to a shift in maintenance work for our meter modules. Previously this work had been budgeted for within our Distribution Operations; however, upon completion of the meter module project, the trailing maintenance for the modules will be managed by Gas Operations.

At the same time we are experiencing increasing costs associated with Gas Operations programs that drive our base rate O&M, our GUIC Rider costs are also increasing. Compared to 2024 actuals, GUIC Rider O&M costs are increasing primarily driven by an increase in work on our transmission pipeline assessment, programmatic replacement/MAOP remediation, and legacy sewer crossbore inspection remediation initiatives. Additional information regarding the GUIC Rider projects and costs can be found in our 2025 GUIC filing

(Docket No. G002/M-24-369) and our 2026 GUIC petition that will be filed in October 2025.

B. Gas Operation's O&M Budget Development and Management

Q. HOW DOES THE COMPANY SET THE O&M BUDGET FOR GAS OPERATIONS?

A. The approach in setting the O&M budget for Gas Operations is similar to the Company's capital budgeting process. Both processes are based on a partnership between the corporate management of overall finances and identified business needs. More specifically, our O&M budgeting process considers our most recent historical spend across the various areas of Gas and applies known changes to labor rates and non-inflationary factors that would be applicable to the upcoming budget years. We also "normalize" our historical spend for any activities embedded in our most recent history that we would not expect to be repeated in the upcoming budget years (*e.g.*, one-time O&M projects). We then couple that normalized historical spend with a review of the anticipated work volumes for the various O&M programs and activities we perform, factoring in any known and measurable changes expected to take effect in the upcoming budget year.

I note that we also factor in any expected efficiency gains we believe would be captured by operational improvement efforts we are continuously working on within our processes and procedures, along with productivity improvements we would expect to achieve via the implementation or wider application of new technologies. These improvements are already factored into our O&M budgets.

Company witness Robinson further details how the Company establishes business area O&M spending guidelines and budgets based on financing availability, the specific needs of business areas, and the overall needs of the Company. The goal is to establish a reasonable annual O&M level that allows Gas Operations to complete priorities that ensure a reasonable level of services to the Company and our customers.

Q. PLEASE EXPLAIN HOW GAS OPERATIONS MONITORS O&M EXPENDITURES AND THE STEPS TAKEN TO MINIMIZE THESE COSTS.

A. We monitor our O&M expenditures on a monthly basis. In partnership with our Finance area, we report out on our monthly and year-to-date actual expenditures versus budgets/forecasts, including deviation explanations for various categories of expenditures. Monthly review meetings are then conducted at various levels to determine any pressure points and remediation plans needed to manage our overall O&M expenditures and ensure proper prioritization of those expenditures.

Further, NSPM takes numerous steps to help minimize the growth in annual O&M expenditures related to Gas Operations. The Company is continuously looking for ways to leverage productivity gains and new technology to improve efficiency. NSPM is in the process of reviewing many of the current work processes in Gas Operations in a concerted effort to streamline these processes while simultaneously enhancing the customer experience.

C. O&M Budget Detail

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

A. In this section of my Direct Testimony, I walk through each of the categories of O&M costs included in our 2026 test year, explaining the costs that are incurred and the drivers of cost changes from prior years in order to demonstrate that our 2026 Gas Operations O&M budget is reasonable.

1. Damage Prevention Program

Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY RELATED TO DAMAGE PREVENTION?

A. In this section of my testimony, I discuss NSPM's damage prevention efforts, the costs associated with the location of underground facilities and performing other damage prevention activities, and the Company's proposal for recovery of damage prevention costs.

Q. WHAT IS THE DAMAGE PREVENTION PROGRAM?

A. The Damage Prevention program helps excavators and customers locate underground infrastructure, consistent with and as required by Minnesota's Gopher State One Call laws, to avoid accidental damage and safety incidents. A reduction in damages also protects the environment by reducing gas emissions. NSPM 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 Minnesota. This program has been designed to ensure compliance with these state and federal regulations, and NSPM relies heavily on contractors to perform this work.

Q. ARE UNDERGROUND DAMAGES A SIGNIFICANT RISK TO NSPM'S GAS DISTRIBUTION SYSTEM?

A. Yes. Whenever excavation and related construction occurs, damage to NSPM's underground facilities continues to be a significant risk to our gas distribution system. As a result, NSPM continues to institute a variety of outreach efforts to excavators regarding the importance of using Gopher State One Call (811) and best excavation practices.

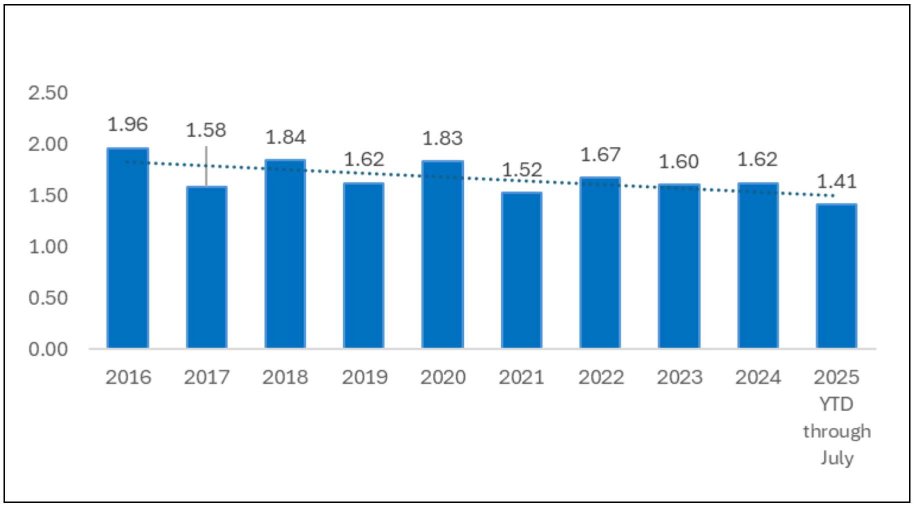
Specifically, it is critical that the Company's mains and services are located accurately before excavating to ensure safety for the workers, as well as the public, around the work site. To that end, NSPM continually re-evaluates its damage prevention programs to increase their effectiveness. The Company also provides leadership in several industry organizations where it obtains and shares information about best practices for reducing public damage. We also include best practices and performance requirements in our vendor contracts, in an effort to continually improve and enhance our performance.

Q. HOW IS NSPM PERFORMING WITH RESPECT TO DAMAGE PREVENTION?

A. As a result of continuing efforts described in more detail below, the damage prevention program has improved year over year performance based on the industry standard measurement metric. Figure 3 below illustrates the number of gas damages per 1,000 locates the Company has experienced since 2016. As indicated by Figure 3, the Company has seen a reduction of more than 28 percent in damages per 1,000 locates on our system since 2016.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Figure 3
Minnesota Gas Damages per 1,000 Locates



Q. HOW ARE LOCATES PERFORMED BY NSPM?

A. The Company is required by law to locate underground facilities when requested. To meet this requirement, the Company is in good standing with Gopher State One Call and utilizes both contracted outside vendors and internal labor to perform locate requests.

Gopher State One Call, formed in response to the legislature's adoption of Minnesota Statutes Chapter 216D, provides a centralized one call center for those planning to excavate to call to request locates. The cost for this service is free to those requesting a locate; however, the Company pays Gopher State One Call a cost per ticket.

To respond to tickets resulting from requests to the centralized one call center, the Company utilizes both internal employees and contracts with external contractors to perform locates and provide field support and audit services. This work is bid out as part of a competitive bid process, and the Company selects the best contractor in terms of quality and cost.

Q. ARE THE NUMBER OF LOCATES PERFORMED GENERALLY CONSISTENT FROM MONTH TO MONTH?

A. No. The number of locates performed are not consistent month to month, with the majority of locates performed during the peak construction period from April through October. Additionally, the actual number of locate requests in a month is also dependent on the weather. For example, colder than average weather in the spring or fall, or rainier weather at any time during the construction season, can impact construction activities in those months, resulting in fewer locates than forecasted. For these reasons, the Company budgets for a full year of damage prevention expenditures.

Q. HOW DOES THE COMPANY BUDGET FOR DAMAGE PREVENTION?

A. The budget for Damage Prevention is based on several factors, including our most recent historical annual locate request volume trends, regional economic growth factors, anticipated investment in infrastructure, and the contract pricing of our Damage Prevention service providers (vendor contracts) estimated to be in effect for the given budget year. However, the quantity and complexity of locates is largely outside the Company's control, as they are heavily driven by requests to Gopher State One Call (811). Further, the Company is required by law to respond to such calls in a timely manner.

Q. WHAT IS THE CURRENT STATUS OF NSPM'S VENDOR CONTRACTS FOR DAMAGE PREVENTION WORK?

A. NSPM currently maintains active contracts with four vendors, expiring in 2026. These agreements were originally established in 2021 following a rigorous competitive bidding process and multiple rounds of negotiation. The initial contract term spanned from 2021 to 2024. In 2023, NSPM successfully negotiated an extension of these contracts, securing continued vendor partnerships.

In August 2025, NSPM issued a request for proposals (RFP) to obtain damage prevention services after expiration of the current contracts. This process involves multiple-qualified contractors to bid on work to ensure competitive pricing. While this RFP process began after budgeting for this current rate case, and was not completed prior to development of this testimony, as I will discuss further below, the Company's 2026 test year budget incorporated anticipated increases in vendor costs that will result from the new contracts to be effective in February 2026. We are anticipating a larger increase in costs in this RFP due to the negotiated extension of contracts in 2023 and an overall market re-evaluation.

Q. WHY DOES THE COMPANY UTILIZE CONTRACTORS TO PERFORM UNDERGROUND LOCATES?

A. Locate requests the Company receives fluctuate in the volume, geographical location including a seasonal surge during construction season when the ground is free of frost. The Company leverages internal employees to sustain year-round requests and utilizes contractors to supplement locate requests during peak construction periods as well as to drive efficiency and flexibility into off-season workloads to ensure demands are met. During 2024, the Company performed more than 205,000 gas locates, and approximately 159,000, or 77 percent, of those locates were performed by contractors.

It is important to strike the right balance between using contractors and our internal bargaining unit employees; this calculus changes over time depending on levels of seasonal work, collective bargaining agreement provisions, risk assessments, contractor costs, workforce availability, and the like. Therefore, it is an ongoing effort to achieve a reasonable balance of internal employees versus contractors attending to damage prevention work.

Q. WHAT WERE THE ACTUAL COSTS ASSOCIATED WITH DAMAGE PREVENTION FROM 2022-2024, AND WHAT ARE THE FORECASTED COSTS FOR 2025 AND 2026?

A. Table 11 below shows the actual O&M costs associated with Damage Prevention in 2022, 2023, and 2024. Table 11 also contains forecasted Damage Prevention costs for 2025 and the 2026 test year.

Table 11
Gas Damage Prevention O&M Expenses 2022-2026
State of Minnesota ($ millions)

Damage Prevention O&M Cost Elements	2022 Actuals	2023 Actuals	2024 Actuals	2025 Forecast	2026 Test Year
Outside Services	$6.5	$6.9	$8.7	$9.1	$12.4
Labor	$0.7	$0.8	$0.7	$0.9	$0.9
Materials	$0.0	$0.0	$0.0	$0.1	$0.0
Other	$0.2	$0.2	$0.2	$0.2	$0.1
Total	**$7.4**	**$8.0**	**$9.7**	**$10.2**	**$13.4**

Q. HOW DID THE ACTUAL DAMAGE PREVENTION IN 2023 AND 2024 COMPARE TO THE FORECASTS IN THE COMPANY'S 2024 GAS RATE CASE?

A. In the Company's 2024 Gas Rate Case, the Company forecasted Damage Prevention costs of $8.4 million in the 2023 bridge year and $9.6 million in the 2024 test year, compared to actuals shown in Table 11 of $8.0 million in 2023 and $9.7 million in 2024. This illustrates that the Company's Damage

Prevention forecasts are typically very close to actuals, even though Damage Prevention costs are dependent on factors outside of the Company's control.

Q. PLEASE EXPLAIN THE INCREASE FROM 2024 ACTUALS TO THE 2026 TEST YEAR BUDGET FOR DAMAGE PREVENTION.

A. The $13.4 million Damage Prevention 2026 test year budget reflects a $3.7 million increase in Damage Prevention costs compared to 2024. This forecast increase is attributable primarily to higher Outside Services cost, which reflects both higher anticipated costs for vendor services due to our ongoing RFP as I describe above, as well as an increase in the forecasted number of locate requests. We anticipate vendor costs will increase due to inflationary pressures, and a tight labor market. Additionally, our workforce bargaining agreement includes an increase in wages for 2025. Company witness Tamra Newman's Direct Testimony discusses the bargaining employee base wages.

Q. CAN YOU EXPLAIN THE FORECASTED INCREASE IN THE VOLUME OF LOCATE TICKETS FROM 2025 TO 2026?

A. In 2026, we are forecasting a two percent increase in the number of locates compared to 2025. The increase in the volume of underground locate requests is consistent with the trend of increasing number of locates and is due to expected increases in public and private industry construction activities such as new building construction, roads and bridges, broadband expansion, and utility replacement. Incremental state and federal infrastructure funding will also drive excavation needs and consequently, one call locate requests.

Q. WHAT OTHER FACTORS IMPACT DAMAGE PREVENTION COSTS IN A PARTICULAR YEAR?

A. While the Company's Damage Prevention test year budget reflects the expected number of locates based on prior year's actuals and forecasted future activity, as well as contractor costs to complete the work, the increasing complexity of locates to be performed can also impact damage prevention costs in a given year. Aging infrastructure and utility congestion present unique challenges. These assets are often difficult to locate using traditional methods and require incremental labor to ensure the accuracy of our locate marks. In cases where traditional locating fails, extra precautions such as document research and vacuum excavation are used to visually identify and confirm the location of our gas mains and services for excavators. Additionally, the Company employs Watch and Protect protocols when excavators are working near our critical assets, which ensures a qualified Company representative is present during excavation to verify asset location and protect our facilities.

Q. HOW PREDICTABLE ARE DAMAGE PREVENTION COSTS?

A. As noted above, while the Company's recent forecasts have been very close to actuals, there are factors outside of the Company's control that can impact actual costs incurred in a given year. For example, the number of locate requests the Company receives and the complexity of locates required in any given year are not within the Company's control, and can vary depending on the economy, the housing and commercial building or renovation markets, and amount of work performed by municipalities. Additionally, the periodic request for pricing and renegotiation of our vendor contracts and internal bargaining agreements at times results in step changes in cost. Further, the Company does not have many opportunities to moderate these costs given our statutory obligations and the limited means of providing these services.

Q. WHAT IS THE COMPANY'S REQUEST WITH RESPECT TO DAMAGE PREVENTION O&M COSTS?

A. Because the costs associated with Damage Prevention over time are outside of the Company's control, and we have few opportunities to moderate these costs given our statutory obligations, and due to the largely seasonal nature of locate work (meaning we largely depend on contractors for efficient deployment of resources) and the limited means of providing these services, the Company requests approval to defer these costs in a tracker account for later recovery.

Q. WHY IS A TRACKER REASONABLE, FROM AN OPERATIONAL STANDPOINT?

A. This approach would support this important safety work that is designed to ensure compliance with state and federal regulations, and it would ensure that customers pay only the actual costs incurred associated with Damage Prevention activities. This would be consistent with how the Commission has supported more current cost recovery for similar work associated with safety regulations and mandated work. For example, like mandated relocations that the Company is required to do when requested, the Company is obligated by statute to perform locates when requested and does not have the ability to defer this work. Factors that are outside of the Company's control, including the number and complexity of locates required, and the costs associated with contracted outside vendors, who, as described above, perform the majority of the locates in Minnesota, can result in Damage Prevention costs in a given year that are either higher or lower than forecasted amounts in the test year.

It is also important to highlight the Company's success in reducing the damages per 1,000 locates over time. While the actual damages vary somewhat by year, we have worked to ensure our contractors are following good practices to avoid gas infrastructure strikes, thereby enhancing public safety. So even as the number of locates is increasing, we are also increasing the benefits of this work and reducing the risks for our customers.

A tracker would provide for recovery of costs associated with this critical safety work that is mandated by law that would otherwise not be captured between rate case test years. The Company therefore proposes to set the base Damage Prevention at the 2026 forecast of $13.4 million for the 2026 test year and track actual costs above or below that amount to be recovered from or returned to customers. Allowing deferral of these costs would support the required Damage Prevention work and ensure customers only pay actual costs incurred. If the tracker is approved, the Company proposes to provide an annual report to update the Commission on costs and would request recovery of the costs in a future proceeding.

Company witness Halama discusses the treatment of the costs associated with Damage Prevention further in his Direct Testimony.

2. Labor

Q. WHAT ARE LABOR O&M COSTS?

A. Labor costs for O&M include a portion of salaries, straight time labor, overtime, and premium time for internal employees who provide natural gas services to our customers.

Q. WHAT AREAS OF THE COMPANY'S GAS BUSINESS INCUR LABOR COSTS?

A. Labor costs incurred by the Gas business are spread across several functional areas:

- **Distribution Operations** provides support for our customers through our Builders Call Line as well as design services;
- **Gas Engineering** provides engineering technical support to ensure safe and compliant operations and maintenance of distribution, transmission, and storage assets;
- **Gas Governance** provides risk management advocacy, interaction with state and federal agencies, and compliance with codes and standards;
- **Gas Operations** is comprised of the gas emergency response organization, statewide operation and maintenance of the high-pressure gas systems, gas control, corrosion services, technical services, and the management of contractors working on certain gas assets;
- **Gas System Strategy and Business Operations** is responsible for strategic direction of the overall gas organization, planning, and budgeting of short-term and long-term projects, provides risk management advocacy as well as streamlines functions from various areas of the Gas organization to ensure continued success and improvement in key business processes, systems, and support; and

- **Geospatial Asset Data** is accountable for advancing the integrity, quality, and function of business unit-related processes, asset data, and applications to meet/surpass industry standards.

These functional areas are focused on the reliability, safety, customer service, operational efficiency, and fiscal oversight necessary to construct, operate, and maintain the gas transmission and gas distribution systems in Minnesota.

Q. WHAT TYPES OF JOBS DOES THE GAS OPERATIONS BUSINESS AREA PROVIDE?

A. Our budget covers quality jobs for a variety of employees across the functional areas described above. A large portion of our workforce that supports gas operations consists of bargaining employees whose compensation and benefits are collectively bargained with International Brotherhood of Electrical Workers (IBEW) locals. The largest portion of the overall business area jobs reside in the Gas Operations functional area. This workforce offers our customers safe and reliable service by performing duties such as locating, gas emergency response, construction, operations, and maintenance. Often, they are required to perform their duties under challenging weather conditions, and they require appropriate fleet, tools, and equipment to maintain a safe and reliable system for our customers.

Q. PLEASE DISCUSS THE TRENDS ASSOCIATED WITH LABOR O&M COSTS FOR GAS OPERATIONS.

A. Overall, our Labor O&M cost has increased since 2024, primarily driven by wage increases, a shift in work on our assets, and an increase in internal labor headcount. As previously mentioned in my testimony, the current labor agreement includes a general wage increase of 3 percent in 2025, and the budget also includes anticipated increases in 2026 that will result from a new labor agreement.

Q. WHY IS THE O&M LEVEL FOR LABOR REASONABLE FOR THE 2026 TEST YEAR?

A. The Company works diligently each year to minimize increases in our O&M costs related to labor, but in certain years we may experience cost fluctuations for labor due to a number of factors. These fluctuations are due to moving new work responsibilities to the Gas Operations area, and the associated additional headcount. Our Labor O&M cost levels demonstrate a balance between reasonable and prudent management while also responding to internal and external changes.

3. Outside Services

Q. WHAT ARE OUTSIDE SERVICES?

A. Outside Services are costs related to the use of contract labor and consultants.

Q. WHAT IS THE BENEFIT TO USING OUTSIDE SERVICES AS OPPOSED TO RELYING SOLELY ON INTERNAL LABOR?

A. Outside Services allows NSPM to increase and decrease staffing levels as workloads require rather than bringing on more full-time staff, and to retain the services of experts as needed for specific tasks or project efforts.

The Company has a negotiated Master Service Agreement with each contractor. These MSAs have per-unit pricing. For example, within the negotiated MSA, the cost per service and the cost to install gas mains is set based on pipe diameter and the required installation technique (*e.g.*, trench, bore, etc.).

Q. WHAT COST CHANGES ARE YOU ANTICIPATING IN THIS AREA FOR THE 2026 TEST YEAR?

A. The 2026 test year reflects an increase in Outside Services O&M due to a shift in work responsibility to Gas Operations. Gas Operations is now responsible for meter maintenance costs associated with the new meter modules that were installed through 2025. This work was previously managed by the Customer Care area, and the cots were included in the Customer Care budget. Overall, the Company generally manages these costs to maintain a reasonable balance between internal labor and outside services to meet the needs of our system. As such, our 2026 budget is a reasonable estimate of likely Gas Operations Outside Services work in 2026.

4. Materials

Q. PLEASE DESCRIBE THE MATERIALS AND COMMODITIES CATEGORY OF O&M COSTS.

A. Gas Operations materials are costs related to consumables, hardware, and refurbished materials used in maintenance and repair operations, as well as tools and small equipment.

Q. WHY DID THE MATERIALS FORECAST DECREASE FOR 2026?

A. The decrease in the forecast for materials in 2026 reflects the change in the need for materials from year to year, but also reflects a reduction in costs due to process improvements.

5. Manufactured Gas Plant (MGP)

Q. CAN YOU PLEASE EXPLAIN BRIEFLY WHAT A MANUFACTURED GAS PLANT SITE IS?

A. Manufactured Gas Plants (MGPs) used large brick ovens to heat coal and other ingredients. As the fuels were heated, they produced gases that were distributed and used by customers for heating, lighting, and cooking, much like natural gas is used today. MGPs generally had both a manufacturing process plant and one or more gas holders. From the plant, the gas was piped to other holders for storage and distribution or directly to communities and customers for their use. Before it was distributed, the gas was purified, and byproducts were removed. The recovery and sale of MGP byproducts were important to plant economics, and byproducts were sometimes stored at the plant site. These plants typically began operations in the late 1800s or early 1900s. By the 1950s, the production of manufactured gas declined as natural gas became available. MGPs were closed and usually dismantled, sometimes leaving behind remnants, including piping and other infrastructure, as well as the byproducts on site. The MGP sites provided valuable benefits to prior customers of our gas services. MGP sites were sometimes owned, operated, or acquired by NSPM. The Company owned and operated MGPs in accordance with industry standards for the times.

Q. CAN YOU EXPLAIN WHY NSPM HAS COSTS RELATED TO THESE SITES?

A. Most MGPs were decommissioned by the 1950s. The environmental conditions related to these historic MGP sites are often discovered today during redevelopment activities. New environmental laws (that typically were first enacted in the 1970s and 1980s) were passed, and they created retroactive liability for investigating and remediating the MGP sites, if formerly owned, operated, or acquired by NSPM. Current environmental laws and regulations today often require utilities to investigate and clean up contaminated MGP sites (and areas downgradient of the MGP sites that may now be impacted by pollution) on a strict liability basis (*i.e.*, where there was no wrongdoing or negligence in how the MGP was originally operated). The costs of resolving these environmental claims are necessary costs of doing business today and are necessary to utilities providing current service to customers today. It is also in the public interest to investigate and remediate MGP sites to ensure protection of human health and the environment.

Q. IS INSURANCE AVAILABLE TO OFFSET COSTS TO INVESTIGATE AND REMEDIATE MGP SITES?

A. Sometimes partial recovery of costs from historic insurers is possible. Environmental insurance for these types of liabilities was generally only available from approximately the 1940s-1980s. Before the 1940s, there was no Comprehensive General Liability coverage for environmental property damage. Beginning in the 1980s, pollution exclusions were added to insurance policies to exclude coverage for these types of liabilities. Many insurers from that era have also now been dissolved. NSPM has litigated with its historic insurers over what coverage may still exist for these types of liabilities. As a result of that litigation and its settlement efforts, NSPM is sometimes able to obtain partial insurance recoveries for MGP sites. In those instances, any insurance recoveries are used to offset the costs of the investigation and cleanup.

Q. PLEASE DISCUSS THE MGP COSTS FOR WHICH NSPM IS RESPONSIBLE.

A. NSPM is responsible for investigation, remediation, monitoring, and restoration costs primarily at the following active MGP sites:

- **Saint Cloud MGP:** During decommissioning of a substation in 2015 in Saint Cloud, Minnesota, stained soil and odors were observed. In early 2016, soil sampling was performed, which identified elevated concentrations of contaminants related to a historic MGP that was present at the site, prior to the construction and operation of the substation. The clean-up and remediation work at the Saint Cloud MGP site began in 2018 and included the excavation of impacted soils, followed by groundwater monitoring. Additional monitoring was performed at the request of the Minnesota Pollution Control Agency (MPCA) in 2021. A request was submitted to the MPCA in 2021 to issue a determination that the investigation, remediation, and monitoring of the plant site is complete. In 2025, MPCA has requested that the

Company perform additional groundwater studies before it will issue a determination that all work at the site is complete. Insurance recovery efforts are complete for this site. Insurance recoveries have offset the costs of the project.

- **Faribault MGP:** This site was previously remediated in the 1990s. However, in 2019 erosion was observed along the shoreline of the Straight River, where historic underground MGP infrastructure continues to be present. This observation triggered additional evaluation of the site and the need to perform shoreline restoration work at the site. That restoration work was completed in 2021. In addition, because clean-up practices and science have evolved in recent times, further assessment was needed of potential vapor conditions at and adjacent to the site. In the 1990s, vapor intrusion was not yet understood. From 2019-2021, vapor assessments were performed and reported at commercial and residential properties at and near the site. At this time, we believe that the investigation, remediation, restoration, and monitoring at the plant site are complete. In 2022, we informed MPCA that we believe our activities are complete, but the agency has not yet verified whether they agree. We continue to maintain the well network at the site and will be working with MPCA to determine if the wells can be properly sealed and closed or whether any additional work is needed.
- **Oxford/Saint Paul MGP:** The MPCA inspected the former Oxford manufactured gas holder site located in Saint Paul in the 1990s. The State confirmed at the time that no further investigation or action was needed, but the science around these sites has recently evolved. In recent years, the MPCA changed its soil gas screening levels for benzene. Because of this change, and because of the presence of known benzene in the area,

the Company assessed and mitigated the site for potential soil gas/vapors. At this time, we believe that the investigation, remediation, restoration, and monitoring at the site are complete. In 2022, we informed MPCA that we believe our activities are complete, but the agency has not yet verified whether they agree.

- **Red Wing.** We are working with the City of Red Wing to evaluate what additional work may be needed at a former MGP site located in Red Wing, prior to anticipated redevelopment of the site by the City. We anticipate additional site investigation activities will commence in late 2025 and depending on the findings from that investigation, additional work may be required at the site in 2026.
- **Stillwater.** We are working with the City of Stillwater to evaluate what additional work may be needed at a former MGP site located in Stillwater, prior to anticipated redevelopment of the site by the City. We anticipate additional site investigation activities will commence in late 2025 and depending on the findings from that investigation, additional work may be required at the site in 2026.

Q. PLEASE IDENTIFY THE MGP O&M COST LEVEL THAT IS INCLUDED IN THE 2026 TEST YEAR.

A. We have included approximately $1.1 million for MGP cost in our 2026 test year. The requirements of these sites vary substantially. For example, we have seen costs as high as over $1.6 million in some years, and in some years, insurance recoveries may largely offset expenditures. Note that insurance recovery is not guaranteed, and when obtained it is typically years after the costs were incurred and money spent. Any recoveries are used to offset costs incurred in a given year, even though these recoveries may be related to amounts expended in prior years.

For future projects, the Company anticipates more work will be needed at not only the sites mentioned above but potentially other MGP sites as they are identified. As such, given historical spending levels and the additional work anticipated, we believe the test year budget of approximately $1.1 million appropriate to represents average costs going forward, but there will be years where higher spend is incurred (for example, when remedial work is performed in the field), and years where lower spend is incurred (for example, when desktop reviews or engineering design work is performed). Any insurance recoveries are uncertain at this time.

Q. HOW DOES THE 2026 MGP O&M COST LEVEL COMPARE WITH PREVIOUS YEARS?

A. As shown in Table 9 above, MGP costs over the last few years vary significantly, with credits in 2022 and 2024 actuals. We anticipate more work will be needed at existing sites – as further site investigation activities are completed – and at new sites, including closure activities and emerging work as the science evolves or new facts arise at any given site. Thus, we anticipate costs will average approximately $1.1 million per year going forward.

Q. WHAT IS THE COMPANY'S REQUEST WITH RESPECT TO MGP O&M COSTS?

A. Because of this variation in spend over time and because of the importance of cleaning up these sites as they are discovered, the Company requests approval to defer these costs in a tracker account for later recovery. This would be consistent with how the Commission has supported cost recovery through trackers for other gas utilities in Minnesota, and how the Company recovers costs for MGP sites in all other jurisdictions outside Minnesota. Any amounts recovered from insurers for MGP liabilities would also be credited back to the tracker. The credits shown for 2022 and 2024 also support why a tracker would be beneficial for customers, because those amounts would have been credited to customers on an annual basis if an MGP tracker had been in place. Additionally, while the 2026 budget of $1.1 million proposed as the baseline is reasonable, for the reasons described above, a tracker will appropriately account for years when spending is below the baseline amount, ensuring customers only pay actual costs incurred.

Further, while the Company is required to clean up these sites at some time, deferral of these costs allows the Company to proceed with the work sooner, which would be beneficial for customers and the environment. If the tracker is approved, the Company proposes to provide an annual report to update the Commission on costs and any insurance recoveries and would request recovery of the costs in a future rate case proceeding.

Company witness Halama discusses the treatment of the costs associated with MGPs further in his Direct Testimony.

6. Transportation

Q. WHAT IS INCLUDED IN THE TRANSPORTATION COST CATEGORY?

A. Transportation costs are incurred in relation to internal fleet assets as directed to O&M accounts on an hourly basis, including cars, trucks, construction equipment, and trailers that help us move our people and equipment where they need to be to provide gas service.

Q. PLEASE IDENTIFY THE TRANSPORTATION O&M COSTS THAT WILL BE INCURRED IN 2026.

A. The Transportation O&M costs to be incurred in 2026 total approximately $3.8 million, which is an increase of $0.5 million compared to 2024 but only slightly higher than transportation costs in 2022. The increase in Transportation costs since 2024 is due primarily to inflationary increases. Company witness Robinson describes the Company's fleet procurement and management in more detail in his Direct Testimony.

7. Other O&M

Q. WHAT IS INCLUDED IN THE OTHER CATEGORY OF O&M COSTS?

A. Other O&M costs incurred by the Gas Operations area are related to employee expenses, facility costs, licensing fees, and first set meter credits.

Q. PLEASE DESCRIBE TRENDS ASSOCIATED WITH OTHER O&M.

A. Most of the expenses in Other O&M are typically smaller amounts, such as for employee travel, that are relatively stable year over year. We also include first set meter credits in Other O&M, which consists of O&M labor, transportation, and miscellaneous material credits associated with the installation of meters. Because of the way meters are accounted for (fully installed costs are capitalized upon purchase), the labor, transportation, and miscellaneous materials used to install this equipment are expensed to O&M upon into avoid accounting for these expenses twice. An equal and opposite credit is then applied upon purchase to offset these actual installation costs that are expensed to O&M. As such, first set meter credits largely offset our other employee costs each year. On a year-over-year basis, Other O&M shows a higher credit amount in 2023, 2025, and 2026 primarily related to first set meter credits. Supply chain challenges delayed many of our meter deliveries in recent years, and manufacturers are catching up on trailing orders. Deliveries in 2023 actuals were high due to manufacturers catching up on trailing orders, and 2024 orders were lower due to significant quantity of deliveries in 2023 and pausing deliveries in 2024, resulting in lower first set credits in 2024. The 2025 and 2026 forecasts reflect first set credits based on expected deliveries.

Q. WHAT DO YOU CONCLUDE REGARDING O&M COSTS FOR THE TEST YEAR?

A. We are experiencing increased costs associated primarily with the demands on our system and increasing costs associated with labor and vendor contracts. We are managing those costs to maintain a reasonable balance between internal labor and contractor work, while necessarily addressing cost increases. Overall, our O&M projections represent reasonable forecasts, based on the need to provide reliable and safe service to customers.

V. COMPLIANCE ISSUES

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

A. In this section, I discuss the compliance issues specific to Gas Operations and the Company's fulfillment of its compliance obligations in conjunction with these requirements. Consistent with the Commission's March 12, 2021 Order in our COVID-19 Relief & Recovery (COVID-19 R&R) docket,[5] I provide information on spending related to the Company's COVID-19 R&R projects.

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[5] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*, Docket No. E,G999/CI-20-492, ORDER DETERMINING THAT PROPOSALS HAVE THE POTENTIAL TO BE CONSISTENT WITH COVID-19 ECONOMIC RECOVERY, (March 12, 2021).

Q. DOES GAS OPERATIONS' BUDGET FOR 2025 AND 2026 INCLUDE ANY ACCELERATED WORK ASSOCIATED WITH THE COVID-19 R&R DOCKET?[6]

A. The accelerated gas projects initially identified in the COVID-19 R&R docket included work related to replacing copper risers and services and installing additional isolation valves. While there are small dollar amounts associated with these projects in the 2025 budget (totaling approximately $16,000), these accounting structures will be closed, and there are no budgeted amounts for these accelerated projects in 2026 and beyond. This portfolio of accelerated gas infrastructure projects provided system benefits by improving system reliability and public safety. Consistent with the Commission's March 12, 2021 Order,[7] the Company has been tracking its spending related to these COVID-19 R&R projects, and the Company has been providing this information to the Commission as part of its quarterly compliance filings in that docket.[8]

Q. DO YOU HAVE ANY OTHER COMMENTS RELATED TO THIS COMPLIANCE REPORTING?

A. Yes. The Company will no longer budget for these projects separately as accelerated projects; rather, any work associated with replacing copper risers and services and installing additional isolation valves will be completed in the normal course of business, and the need for these projects and the associated costs will be supported in our rate case filings. As such, we request that the Company no longer be required to provide this separate reporting in future rate

[6] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*, Docket No. E,G999/CI-20-492, REPORT--COVID-19 RELIEF & RECOVERY, (June 17, 2020).
[7] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*, Docket No. E,G999/CI-20-492, ORDER DETERMINING THAT PROPOSALS HAVE THE POTENTIAL TO BE CONSISTENT WITH COVID-19 ECONOMIC RECOVERY, (March 12, 2021).
[8] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery from the COVID-19 Pandemic*, Docket No. E,G999/CI-20-492 2023, SECOND QUARTER REPORT COVID-19 RELIEF & RECOVERY, (July 31, 2023).

cases. The Company will continue reporting on each of these projects and programs in the annual reports in the COVID R&R docket.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve Gas Operations' capital and O&M budgets presented in this rate case. Our planned capital investments are managed appropriately and are established to continue to support the safety and reliability of our system, and to serve new customers. The budgets we propose are a reasonable representation of the activities we will undertake to continue to serve our customers through 2026 and beyond.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

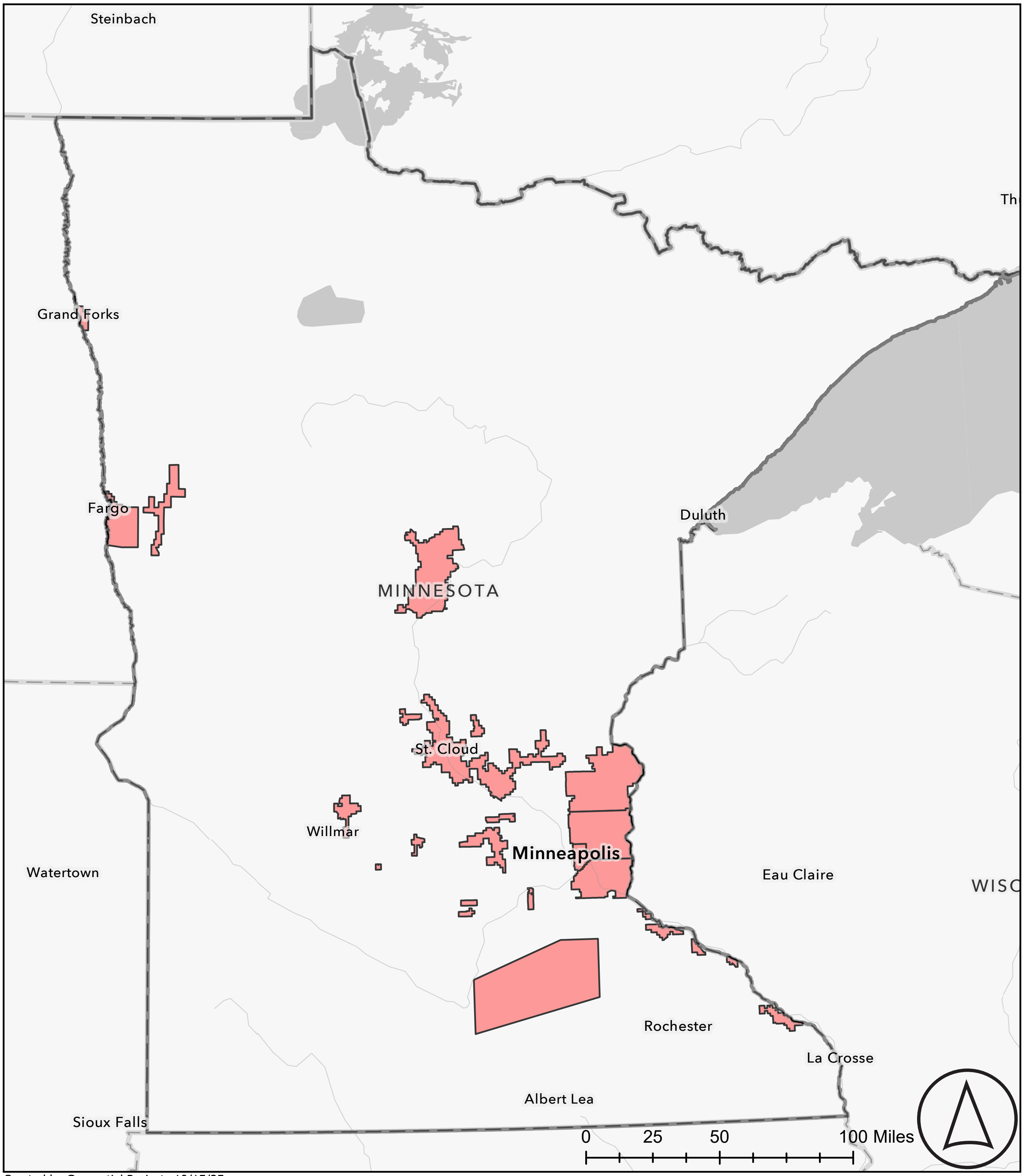
Statement of Qualifications

Alicia E. Berger

I have a Bachelor of Science degree in Business Management from St. Catherine University, St. Paul, Minnesota. I began my career at Xcel Energy in May 2007 as a Damage Facility Analyst in the Damage Prevention department of Xcel Energy Services, Inc., the service company subsidiary of Xcel Energy. Within Damage Prevention, I held positions of increasing responsibility including Damage Prevention Supervisor and Senior Operations Manager. My responsibilities during this period included providing supervisory direction to internal and external contract locating resources across the Xcel Energy Upper Midwest footprint, ensuring compliance with state and Federal regulations, and working with stakeholders through partnership and engagement to reduce underground excavation damages to enhance public safety.

In March of 2019, I moved to the position of Operations Planning and Operational Performance Manager in the Performance and Planning Continuous Improvement department. In this role I was responsible for identifying strategic business plan processes and provided governance to drive operational and finance performance for Xcel Energy distribution electric organization. Additionally, I would lead key projects and served as a liaison to represent the organization with key business partners.

I was promoted to the position of Director of Gas Operations within the Gas department in January 2020 and subsequently Regional Vice President, Gas Operations in August 2023. In my role, I lead the development and execution of both short- and long-term business plans that drive achievement of strategic objectives. I also oversee the creation and implementation of labor strategies that ensure flexible and efficient use of resources. I am responsible for the operation and maintenance of the regional gas distribution system, with a strong emphasis on fostering a culture of accountability, prioritizing employee and public safety, enhancing service reliability, and promoting customer satisfaction. My responsibilities include developing operational plans that optimize performance, and I am accountable for reliability, emergency response, regulatory compliance, customer satisfaction, and the overall safety performance.



Created by Geospatial Projects 10/15/25
MN Dept Natural Resources, Esri, TomTom, Garmin, FAO, NOAA, USGS, EPA, NPS, USFWS, Xcel Energy Service Center Boundary

									Actual Additions			Forecasted Additions	
Line #	Gas Witness	Major Category	Function Class Description	Project ID (WBS2)	Project Name	Project Type	Rate Review Category	Major Project	2022	2023	2024	2025	2026
1	Berger	Safety	**Gas Distribution Plant**	**E.0010011.009**	MN/Inside Meter Move-out Svc Renewa	Discrete	Safety	Inside Meter Move-out		$ (418,858)	$ (731,002)		$ (3,515,199)
2	Berger	Safety	**Gas Distribution Plant**	**E.0010011.008**	MN/Inside Meter Move-out Purchase	Discrete	Safety	Inside Meter Move-out				$ (165,001)	$ (772,410)
3	Berger	Safety	**Gas Distribution Plant**	**E.0010011.019**	NSM-MN-Gas-Locates	Discrete	Safety	Capitalized Locating Costs - Gas		$ (514,450)	$ (1,016,203)	$ (137,758)	$ (648,000)
4	Berger	Safety	**Gas General Plant**	**A.0006059.523**	MN-Gas Tools & Equip	Discrete	Safety - Other		$ (544,110)	$ (1,156,245)	$ (339,925)	$ (109,999)	$ (551,512)
5	Berger	Safety	**Gas General Plant**	**A.0006059.009**	MN-Dist Gas Tools and Equip	Discrete	Safety - Other		$ (694,103)	$ (265,422)	$ (1,736,376)	$ (381,923)	$ (475,026)
6	Berger	Safety	**Gas General Plant**	**A.0006059.010**	ND-Dist Dist Tools and Equip	Discrete	Safety - Other		$ (47,317)	$ (51,149)	$ (71,534)	$ (93,163)	$ (110,273)
7	Berger	Safety	**Gas Distribution Plant**	**E.0000006.039**	Capitalized Locating Costs-Gas	Discrete	Safety	Capitalized Locating Costs - Gas	$ 536	$ (108)		$ (53)	$ (0)
8	Berger	Safety	**Gas Distribution Plant**	**E.0010011.009**	MN/Inside Meter Move-out Svc Renewa	Discrete	Safety	Inside Meter Move-out	$ (50,248)			$ (1,528,471)	
9	Berger	Safety	**Gas Distribution Plant**	**E.0010011.019**	NSM-MN-Gas-Locates	Discrete	Safety	Capitalized Locating Costs - Gas	$ (505,093)				
10	Berger	Safety	**Gas General Plant**	**A.0005014.163**	MN Gas General Office Equip	Discrete	Safety - Other					$ (1,244,404)	
11	Berger	Safety	**Gas General Plant**	**E.0000357.001**	MN/Honeywell SCBA unit replacement	Discrete	Safety - Other					$ (356,624)	
12	Berger	Reliability	**Gas Distribution Plant**	**E.0000225.001**	MN/NWB/RENF/R400 Inlet Renf Ph.1	Discrete	Reliability	R400 Inlet Reinforcement Phase 1					$ (18,674,012)
13	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.002**	MN - Gas Service Renewal Blanket	Routine	Reliability	Service Renewal/Cut-off Routine	$ (2,626,474)	$ (2,473,580)	$ (3,327,509)	$ (4,314,067)	$ (3,322,758)
14	Berger	Reliability	**Gas Distribution Plant**	**E.0000007.032**	NSPM Week 4 SES Accrual	Routine	Reliability - Other						$ (2,174,638)
15	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.001**	MN - Gas Main Renewal Blanket	Routine	Reliability	Main Renewal Routine	$ (1,094,669)	$ (2,245,843)	$ (1,919,357)	$ (931,756)	$ (2,073,905)
16	Berger	Reliability	**Gas Distribution Plant**	**E.0010016.001**	MN - Gas Main Reinforcements Blanke	Routine	Reliability	Main Reinforcement Routine	$ (2,449,745)	$ (1,434,382)	$ (1,794,480)	$ (1,400,315)	$ (1,706,763)
17	Berger	Reliability	**Gas General Plant**	**E.0010053.015**	MN/EOL RTU Replacement	Discrete	Reliability	End-of-Life RTU Replacement				$ (710,338)	$ (1,688,948)
18	Berger	Reliability	**Gas General Plant**	**E.0010053.006**	NSPM/GDIST/PRESSURE MONITOR ERXs MN	Discrete	Reliability - Other		$ (22,456)	$ (259,035)	$ (31,307)	$ (92,103)	$ (134,835)
19	Berger	Reliability	**Gas Intangible Plant**	**D.0000204.002**	MN/Landbase & GPS ConflationProject	Discrete	Reliability - Other						$ (33,518)
20	Berger	Reliability	**Gas Distribution Plant**	**E.0000004.084**	MN - Service Retro Fit AG Prot	Routine	Reliability - Other		$ (75,330)		$ (123)		
21	Berger	Reliability	**Gas Distribution Plant**	**E.0000008.007**	NW\Howard Lake Reinforcemnt	Discrete	Reliability - Other		$ (333,504)	$ (68)	$ 32,570		
22	Berger	Reliability	**Gas Distribution Plant**	**E.0000009.091**	Replace obsolete regulators -	Discrete	Reliability - Other			$ -	$ (10,140)		
23	Berger	Reliability	**Gas Distribution Plant**	**E.0000092.001**	MN/SHV/Victoria St N\6in reinfcmt	Discrete	Reliability - Other			$ (373,629)	$ (1,375)		
24	Berger	Reliability	**Gas Distribution Plant**	**E.0000115.001**	MN/RENF/STP/Josephine Rd M008 Reinf	Discrete	Reliability - Other			$ (804,695)	$ (61,236)	$ 56,241	
25	Berger	Reliability	**Gas Distribution Plant**	**E.0000126.001**	MN/GAS/ R4396 Move AboveGrade	Discrete	Reliability - Other				$ (123,719)		
26	Berger	Reliability	**Gas Distribution Plant**	**E.0000126.010**	MN/GAS/R4396 Move Above Grade-Main	Discrete	Reliability - Other			$ (429,527)	$ (10,700)		
27	Berger	Reliability	**Gas Distribution Plant**	**E.0000167.001**	MN/NSPM/Mendota Sta/Replace Heater	Discrete	Reliability - Other			$ (962,878)	$ 127,588		
28	Berger	Reliability	**Gas Distribution Plant**	**E.0000203.002**	MNGDOPS LeakSurvey Blkt Cap DR/Fr O	Routine	Reliability - Other			$ (75,586)	$ (128,584)	$ (48,906)	
29	Berger	Reliability	**Gas Distribution Plant**	**E.0000228.001**	MN/STCL/2023 Reinf/Big Lake Reinfor	Discrete	Reliability - Other			$ (471,714)	$ (286,730)		
30	Berger	Reliability	**Gas Distribution Plant**	**E.0000232.002**	MNGDOPS Rsp to Emergcy Blkt Cap DR/	Routine	Reliability - Other			$ (68,582)	$ (98,851)	$ (48,295)	
31	Berger	Reliability	**Gas Distribution Plant**	**E.0010001.004**	MN/Meter Module Meter Exchange	Discrete	Reliability	Meter Module Replacement		$ (5,657,367)	$ (7,262,588)	$ (6,922,788)	
32	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.013**	MN/R&R/Distribution Isolation Valve	Discrete	Reliability - Other			$ (193,242)		$ (106)	
33	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.014**	MN/R&R/Copper Service Renewal	Discrete	Reliability - Other		$ (15,430)	$ (178,836)	$ (775)	$ 16,450	
34	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.016**	MN Gas Cathodic Protection Blanket	Routine	Reliability - Other		$ (212,350)	$ (346,096)	$ (345,095)	$ (287,265)	
35	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.018**	MN - Gas Service Cutoff Blanket	Routine	Reliability	Service Renewal/Cut-off Routine		$ (5,615)			
36	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.020**	NSM-MN-GasDist-Mixed-OQ	Routine	Reliability - Other		$ (244,973)	$ (321,502)	$ (298,918)	$ (248,426)	
37	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.021**	NSM-MN-GasDist-Mixed-OQ-GER	Routine	Reliability - Other		$ (46,611)	$ (6,836)	$ (12,178)	$ (20,826)	
38	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.004**	NSPM - Newport- HWY 149 Renewal - 1	Discrete	Reliability - Other			$ 1,360			
39	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.009**	MN\STC\2019 Jefferson Blvd Reinf	Discrete	Reliability - Other			$ 2,227	$ 1,330		
40	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.018**	MN/Becker / Big Lake Entitlement	Discrete	Reliability - Other		$ (1,736,025)	$ 5,697			
41	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.023**	MN/NW/Inglewood Dr Phase 2 Reinforc	Discrete	Reliability - Other			$ 53,346			
42	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.024**	MN/NPT/CTG/M030 System Replacement	Discrete	Reliability - Other			$ (412,180)			
43	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.025**	MN/NW/Kandiyohi Farmtap	Discrete	Reliability - Other			$ 3,074			
44	Berger	Reliability	**Gas Distribution Plant**	**E.0010038.048**	MN/Redwing -Service Controls Upgrad	Discrete	Reliability - Other			$ (7,992)		$ 7,966	
45	Berger	Reliability	**Gas Distribution Plant**	**E.0010038.049**	MN/St Cloud - Service Controls Upgr	Discrete	Reliability - Other			$ (0)			
46	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.002**	MN/STP/Forest St Bridge Xing	Discrete	Reliability - Other			$ 0		$ (3,274,939)	
47	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.008**	MN/STC/Royalton 6"Poly Reinforceme	Discrete	Reliability - Other			$ 59,680			
48	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.017**	MN/SE/LC/LAKESHORE DR (HWY61) 2020	Discrete	Reliability - Other		$ (1,853)	$ 2,469			
49	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.022**	MN/NPT/STP/M002 System Replacement	Discrete	Reliability - Other			$ (53,911)			
50	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.025**	MN/NW/New Main/Shakopee/Marystown R	Discrete	Reliability - Other		$ (17,343)	$ (7,097)			
51	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.028**	MN/NSPM-St Cloud/ Renew 8 inch Dist	Discrete	Reliability - Other			$ (697,840)		$ (5,760)	
52	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.033**	MN/STCL/2023 Recon/Division Street	Discrete	Reliability - Other			$ (261,536)	$ (779,660)		
53	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.002**	MN/WBL/HGO/Forest Blvd S008 system	Discrete	Reliability - Other			$ 105,652			
54	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.003**	MN/WYO/HML/Bunker Lake Blvd 8" main	Discrete	Reliability - Other			$ 208,930			
55	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.020**	MN/NW/Reinforcement/STC/Ridgewood L	Discrete	Reliability - Other		$ (4,050)	$ 33,476			
56	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.025**	MN/STC/Darrow Ave SE Delano 6"PE R	Discrete	Reliability - Other			$ (155,538)			
57	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.027**	MN/NW/STC/SAUK RAPIDS/MGSL RNFC	Discrete	Reliability - Other		$ (85,624)	$ (5,868)	$ 9		
58	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.028**	MN/NW/RNFC/STC/ST AUGUSTA/CNTY 75	Discrete	Reliability - Other		$ (1,066,451)	$ 89,742			
59	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.031**	MN/NPT/2022 Reinforcement/Robert S	Discrete	Reliability - Other				$ (177,848)		
60	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.032**	MN/WBL/Buffalo St Reinforcement	Discrete	Reliability - Other		$ (342,738)	$ 42,209		$ (1,382)	
61	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.033**	MN/NPT/2022 Reinforcement/Woodbury	Discrete	Reliability - Other		$ (649,325)	$ (19,630)			
62	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.034**	MN/NPT/2022 Reinforcement/Woodbury	Discrete	Reliability - Other		$ (839,122)	$ (1,674,658)	$ 3,502	$ 1,429	
63	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.035**	MN/GRT/Dellwood Rd N/5400ft 4in rei	Discrete	Reliability - Other		$ (269,862)	$ 20,487			
64	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.036**	MN/WBL/Lake Ave/3300ft 6in reinforc	Discrete	Reliability - Other		$ (291,955)	$ (64,870)	$ 6,569		
65	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.037**	MN/NW/BRD/Whitefish/FatherFoleyDr 4	Discrete	Reliability - Other		$ (212,838)	$ (176,167)			
66	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.005**	MN/Sauk Rapids\ 2nd Ave S AG Reg	Discrete	Reliability - Other			$ (227,097)	$ (23,417)		
67	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.025**	MN/STP/ STP/ R172 Reg Station Rebui	Discrete	Reliability - Other			$ 13			
68	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.026**	MN\BRD\Filter Separator Installatio	Discrete	Reliability - Other			$ (89,201)			
69	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.028**	MN/Delano/Convert/ Install TBS-Reg	Discrete	Reliability - Other			$ (936,101)	$ 130,723	$ (433,947)	
70	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.029**	MN/NW/Delano & Watertown MAOP Split	Discrete	Reliability - Other			$ 9,943			

									Actual Additions			Forecasted Additions	
Line #	Gas Witness	Major Category	Function Class Description	Project ID (WBS2)	Project Name	Project Type	Rate Review Category	Major Project	2022	2023	2024	2025	2026
71	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.032**	MN/STP/ RSV/ R059 Reg Station Rebui	Discrete	Reliability - Other		$ (319,585)	$ 2,147		$ 5,106	
72	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.033**	MN/Delano Convert Inst TBS-Reg Stat	Discrete	Reliability - Other		$ (8,386,578)	$ (2,400,425)	$ 8,193		
73	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.036**	MN/NPT/WSP/R361 Reg Station Rebuild	Discrete	Reliability - Other				$ (1,436,731)	$ 296,951	
74	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.038**	MN/STP/STP/R378 Reg Rebuiild	Discrete	Reliability - Other					$ (335,302)	
75	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.039**	MN/EGF/Gas/Replace Original Odorize	Discrete	Reliability - Other			$ 1,782			
76	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.040**	MN/NPT/MEH/R365 Building Rebuild	Discrete	Reliability - Other			$ (352,367)	$ 254,118		
77	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.047**	MN/NW/Reinforcemnt/STC/35thStNE Reg	Discrete	Reliability - Other		$ (621,075)	$ (62,361)	$ 683,227		
78	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.048**	NW/Reinforcement/STC/Sauk Rapid Reg	Discrete	Reliability - Other			$ (55,395)			
79	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.049**	NSPM Reg Stations - Pilot Heater In	Discrete	Reliability - Other			$ (104,756)	$ (286)		
80	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.053**	MN/NW/REL/WSTC/MN BLVD	Discrete	Reliability - Other			$ (113,883)			
81	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.054**	MN/STC/2022 RegStn Upgrades	Discrete	Reliability - Other			$ (33,639)			
82	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.058**	MN/North St Paul/Henry and County B	Discrete	Reliability - Other					$ 0	
83	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.060**	MN/WBL/SHV/R398 Block Valve Replace	Discrete	Reliability - Other					$ (1,502)	
84	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.061**	MN/New Brighton/H005 Old HWY 8 Relo	Discrete	Reliability - Other			$ (496,913)	$ 15,516		
85	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.062**	MN\STP/R410 Pilot Heater Replacemen	Discrete	Reliability - Other			$ (67,890)	$ (11,685)		
86	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.063**	MN/STP/R537 Pilot Heater Replacemen	Discrete	Reliability - Other					$ (14,939)	
87	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.069**	MN/RW/R4673 Replacement Due To Corr	Discrete	Reliability - Other			$ (149,333)	$ (7,342)		
88	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.073**	MN/PRT/RBLD Princeton 3in Valve Rpl	Discrete	Reliability - Other					$ 1,012	
89	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.075**	MN/SCL/UPGD/Sherco Flow Reading	Discrete	Reliability - Other					$ (21,527)	
90	Berger	Safety	**Gas Distribution Plant**	**A.0002127.001**	NSPM/Replace MDPE to HDPE	Routine	Safety - Other					$ (1,680,334)	
91	Berger	Reliability	**Gas Distribution Plant**	**E.0000300.001**	MN/CAP/NMR/RENW/LincolnRd/4800ft4in	Discrete	Reliability - Other				$ (227,714)	$ (1,852)	
92	Berger	Reliability	**Gas Distribution Plant**	**E.0000336.001**	MN/SCL/RENF/3rd St N	Discrete	Reliability - Other					$ (2,735,702)	
93	Berger	Reliability	**Gas Distribution Plant**	**E.0000338.001**	MN/NSPM/H005/R398 RENEWAL - RS	Discrete	Reliability - Other					$ (390,857)	
94	Berger	Reliability	**Gas Distribution Plant**	**E.0000341.001**	MN/WTT/RENW/MNTRS/JeffersonAve DIMP	Discrete	Reliability - Other				$ (498,187)	$ 5,715	
95	Berger	Reliability	**Gas Distribution Plant**	**E.0000342.001**	MN/FRL/NMR/RENF/240thSt/12000ft 8in	Discrete	Reliability - Other				$ (1,698,421)	$ (1,729)	
96	Berger	Reliability	**Gas Distribution Plant**	**E.0000343.001**	MN/FRL/NMR/RENF/8th St/5200ft 6in	Discrete	Reliability - Other				$ (809,578)	$ 20,077	
97	Berger	Reliability	**Gas Distribution Plant**	**E.0000344.001**	MN/FRL/NMR/RENF/202nd St/7600ft 4in	Discrete	Reliability - Other				$ (781,655)		
98	Berger	Reliability	**Gas Distribution Plant**	**E.0000420.001**	MN//SCL/RENF/St Cloud SC Mains	Discrete	Reliability - Other				$ (674,580)	$ 34,266	
99	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.036**	MN/RICE ST/Replace F16BBL Gauges	Discrete	Reliability - Other					$ (24,686)	
100	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.005**	MN/Princeton/2019 Reinforcement	Discrete	Reliability - Other				$ 37,869		
101	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.006**	MN/NW-STCloud/Montrose/Upgrading R1	Discrete	Reliability - Other				$ 14,366	$ (14,353)	
102	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.008**	MN/Mendota Heights/R359 Controller	Discrete	Reliability - Other				$ 295		
103	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.037**	MN/STP/RSV/R037 Reg Rebuild	Discrete	Reliability - Other					$ (57,188)	
104	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.076**	MN/NEW/IGH/RBLD/LakeCity TBS 5Yr TD	Discrete	Reliability - Other				$ (19,883)		
105	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.077**	MN/NW/Sartell/Sartell HS Reg Sta	Discrete	Reliability - Other					$ 3,578	
106	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.082**	MN/NW//STC/R4500 INSTALL	Discrete	Reliability - Other				$ (649,585)		
107	Berger	Reliability	**Gas Distribution Plant**	**E.0000126.008**	Gas/MN/MHD/ Above Grade R4651	Discrete	Reliability - Other					$ (206,898)	
108	Berger	Reliability	**Gas Distribution Plant**	**E.0000126.011**	Gas/MN/MHD/ Above Grade R4650	Discrete	Reliability - Other					$ (55,919)	
109	Berger	Reliability	**Gas Distribution Plant**	**E.0000126.012**	MN/MHD/ Above Grade R4650/Main work	Discrete	Reliability - Other					$ (53,581)	
110	Berger	Reliability	**Gas Distribution Plant**	**E.0000126.015**	MN/MHD/R4656 Mains/17th & 9th	Discrete	Reliability - Other					$ (893)	
111	Berger	Reliability	**Gas Distribution Plant**	**E.0000424.001**	MN/SCL/RENF/St Cloud CR1 Reinf	Discrete	Reliability - Other					$ (99,548)	
112	Berger	Reliability	**Gas Distribution Plant**	**E.0000465.001**	MN/SPP/RBLD/MRG/R6000&MS Retire	Discrete	Reliability - Other					$ (8,318)	
113	Berger	Reliability	**Gas Distribution Plant**	**E.0000465.002**	MN/SPP/RENW/MRG Main Renewal	Discrete	Reliability - Other					$ (1,298,360)	
114	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.006**	MN - Gas Asset Health WCF	Routine	Reliability - Other						
115	Berger	Reliability	**Gas Distribution Plant**	**E.0010016.002**	MN - Gas Capacity WCF	Routine	Reliability - Other						
116	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.031**	MN/Saint Michael IP Reinforcement	Discrete	Reliability - Other					$ (545,065)	
117	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.015**	MN/STP/RSV/R037 Reg Rebuild - Main	Discrete	Reliability - Other					$ (109,971)	
118	Berger	Reliability	**Gas Distribution Plant**	**E.0010053.034**	MN/WDB/R541/Woodlane Dr&Valley Cree	Discrete	Reliability - Other					$ (10,282)	
119	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.035**	MN/NPT/MPW/ M024 Retirement	Discrete	Reliability - Other					$ (61)	
120	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.083**	MN/MDEL/SML/UPGD/R0119 Stat Rplce	Discrete	Reliability - Other					$ (139,513)	
121	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.085**	MN/RSV/RENW/MNV\R502 rebuild	Discrete	Reliability - Other					$ (98,735)	
122	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.086**	MN/RSTR/MEH/RBLD/MENDOTA STA/R358	Discrete	Reliability - Other					$ (151,804)	
123	Berger	Reliability	**Gas Distribution Plant**	**E.0000518.001**	Minnesota/Replace obsolete odorizer	Discrete	Reliability - Other						
124	Berger	Reliability	**Gas Distribution Plant**	**E.0000524.001**	MN/Replace TBS Line Heaters	Discrete	Reliability - Other						
125	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.045**	MN/Mendota Heights/Mendota Station	Discrete	Reliability - Other						
126	Berger	Reliability	**Gas Distribution Plant**	**E.0000012.025**	MN-Placeholder Discrete Proj with n	Routine	Reliability - Other						
127	Berger	Reliability	**Gas Distribution Plant**	**E.0010011.007**	MN - Quarantine Pipe Replacement 20	Routine	Reliability - Other		$ 36,492				
128	Berger	Reliability	**Gas Distribution Plant**	**E.0010033.016**	MN/St Cloud/Sartell Sys Cap HP Pipe	Discrete	Reliability - Other		$ (4,495,474)				
129	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.001**	STP/STP/Lafayette Bridge Xing	Discrete	Reliability - Other		$ (25,554)				
130	Berger	Reliability	**Gas Distribution Plant**	**E.0010043.020**	MN/STP/FLH/M007 System Replacement	Discrete	Reliability - Other		$ (414,234)				
131	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.013**	MN/St Cloud/Sartell Sys Cap HP Reg	Discrete	Reliability - Other		$ (33,304)				
132	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.014**	MN/St Cloud/Sartell Sys Cap Pipe	Discrete	Reliability - Other		$ (233,730)				
133	Berger	Reliability	**Gas Distribution Plant**	**E.0010048.022**	MN/NW/Reinforcement/STC/35th St NE	Discrete	Reliability - Other		$ (133,960)				
134	Berger	Reliability	**Gas Distribution Plant**	**E.0010075.027**	MN/Filter Separator Installation Pr	Discrete	Reliability - Other		$ (85,722)				
135	Berger	Reliability	**Gas General Plant**	**A.0006059.516**	NSPM-Gas OT Cyber Security	Discrete	Reliability - Other					$ (10,022)	
136	Berger	Reliability	**Gas General Plant**	**E.0000024.014**	NSPM Comm Equip - Dist Meter/R	Routine	Reliability - Other		$ (17,128)	$ (5,711)		$ (8,115)	
137	Berger	Reliability	**Gas General Plant**	**E.0010023.001**	MN - Gas Communication Equip. Blank	Routine	Reliability - Other			$ (3,716)		$ (2,469)	
138	Berger	Reliability	**Gas General Plant**	**E.0010023.002**	MN/Meter Module Replacement	Discrete	Reliability	Meter Module Replacement		$ (8,255,805)	$ (24,061,843)	$ (9,893,812)	
139	Berger	Reliability	**Gas General Plant**	**E.0010024.002**	ND/Meter Module Replacement	Discrete	Reliability	Meter Module Replacement		$ (394,053)	$ (2,902,648)	$ (1,496,490)	
140	Berger	Reliability	**Gas General Plant**	**E.0010053.001**	MN/CP/ GAS Rectifier Compliance Rea	Discrete	Reliability - Other			$ (382)			
141	Berger	Reliability	**Gas General Plant**	**E.0010053.007**	NSPM/GDIST/PRESSURE MONITOR ERXs Ma	Discrete	Reliability - Other			$ (19,642)			

									Actual Additions			Forecasted Additions	
Line #	Gas Witness	Major Category	Function Class Description	Project ID (WBS2)	Project Name	Project Type	Rate Review Category	Major Project	2022	2023	2024	2025	2026
142	Berger	Reliability	**Gas General Plant**	**E.0010053.022**	MN/Becker/ Big Lake Entitlement	Discrete	Reliability - Other				$ (3,905)		
143	Berger	Reliability	**Gas General Plant**	**E.0010054.003**	NSPM/GDIST/PRESSURE Monitor ERXs ND	Discrete	Reliability - Other		$ (6,800)	$ (15,589)	$ (5,209)		
144	Berger	Reliability	**Gas General Plant**	**E.0000138.002**	ND/Fargo HP OPP/RTU/Comms	Discrete	Reliability - Other					$ (126,911)	
145	Berger	Reliability	**Gas General Plant**	**E.0010053.025**	MN/NW/Reinf/STC/R4500/COMMS	Discrete	Reliability - Other				$ (5,326)		
146	Berger	Reliability	**Gas General Plant**	**E.0010053.026**	MN/BRD/UPGD/BR6 ERX Replace/Comms	Discrete	Reliability - Other				$ (12,739)		
147	Berger	Reliability	**Gas General Plant**	**E.0010053.030**	MN//SPI//SpicerDRS ERX Instl/Comms	Discrete	Reliability - Other					$ (5,646)	
148	Berger	Reliability	**Gas General Plant**	**E.0010053.031**	MN/MDEL/BRV/Blackdog - RTU RPL	Discrete	Reliability - Other					$ (155,583)	
149	Berger	Reliability	**Gas General Plant**	**E.0010053.032**	MN/RED/RDW/PIIC-RTU RPL/Comms	Discrete	Reliability - Other					$ (165,713)	
150	Berger	Reliability	**Gas General Plant**	**E.0010053.035**	MN/SCL/R4352 ERX Replacement	Discrete	Reliability - Other				$ (2,234)	$ (6,842)	
151	Berger	Reliability	**Gas General Plant**	**A.0006059.461**	MN Install Gas Communication E	Routine	Reliability - Other					$ 1,868	
152	Berger	Reliability	**Gas General Plant**	**E.0000246.003**	MN/HST/NPT-592 Langdon TBS/ERX	Discrete	Reliability - Other					$ (6,445)	
153	Berger	Reliability	**Gas General Plant**	**E.0000338.003**	MN/NSPM/WBL/H005/R398 RENEWAL - ERX	Discrete	Reliability - Other					$ (4,423)	
154	Berger	Reliability	**Gas General Plant**	**E.0000409.001**	ND/FGO/2024 HoraceHP ExtensionComms	Discrete	Reliability - Other					$ (10,646)	
155	Berger	Reliability	**Gas General Plant**	**E.0010053.037**	MN/WYO/TYF/R493TaylorsFalls/RTU RPL	Discrete	Reliability - Other					$ (158,069)	
156	Berger	Reliability	**Gas General Plant**	**E.0010054.005**	ND/GF/INSTL/RS 4495 ERX/Comms	Discrete	Reliability - Other					$ (5,703)	
157	Berger	Safety	**Gas General Plant**	**E.0000486.003**	MN/STP/AMLD/Unit Purchases	Discrete	Safety	AMLD Unit Purchases					(2,118,180)
158	Berger	Reliability	**Gas General Plant**	**E.0000024.017**	NSPM Comm Equip - Trans Meter/	Routine	Reliability - Other		$ (115)				
159	Berger	Reliability	**Gas General Plant**	**E.0000042.005**	MN/WBL/County Rd B Replacement-NSP	Discrete	Reliability - Other		$ (9,425)				
160	Berger	Reliability	**Gas General Plant**	**E.0010053.014**	MN/Inver Hills/Lateral RTU Replace	Discrete	Reliability - Other		$ (14,472)				
161	Berger	Reliability	**Gas General Plant**	**E.0010054.002**	NSPM/GDIST/PRESSURE Monitor ERXs ND	Discrete	Reliability - Other		$ (6,528)				
162	Berger	Reliability	**Gas Intangible Plant**	**D.0001855.001**	MN/Gas GPS Data Model Project	Discrete	Reliability - Other					$ (34)	
163	Berger	Reliability	**Gas Intangible Plant**	**D.0002484.001**	MN/Urbint Software/DP-2021	Discrete	Reliability - Other		$ (150,465)				
164	Berger	Reliability	**Gas Transmission Plant**	**E.0000041.026**	MN/Wescott/Odorizer rebuild and rep	Discrete	Reliability - Other			$ (507,867)	$ 75		
165	Berger	Reliability	**Gas Transmission Plant**	**E.0010043.031**	MN/TYF/Taylors Falls/TBS Odorizer	Discrete	Reliability - Other				$ (251,641)	$ 10,497	
166	Berger	Reliability	**Gas Transmission Plant**	**E.0010073.003**	Repl 12in Upper55 to SStPaul R	Discrete	Reliability - Other			$ (107,525)			
167	Berger	Reliability	**Gas Transmission Plant**	**E.0010073.009**	MN/NW/MN/NW/Granite City Retirement	Discrete	Reliability - Other					$ (767)	
168	Berger	Reliability	**Gas Transmission Plant**	**E.0010073.010**	NSPM/IGH/Rich Valley Sta/ R506 Inle	Discrete	Reliability - Other		$ (117,315)	$ 12,687			
169	Berger	Reliability	**Gas Transmission Plant**	**E.0010073.017**	MN/WSTN/BLUE LAKE/CP MITIGATION	Discrete	Reliability - Other			$ (30,514)			
170	Berger	Reliability	**Gas Transmission Plant**	**E.0010073.020**	MN/TRS/2023 Valve Rplcmt/Black Dog	Discrete	Reliability - Other				$ (5,607)		
171	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.021**	MN/MHD/Replace Line Heater at MHD T	Discrete	Reliability - Other			$ 2,889			
172	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.056**	MN/SCL/East St Cloud Odorizer Proje	Discrete	Reliability - Other				$ (951,951)	$ (26,870)	
173	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.068**	MNGas/Moorhead-TBS odorizer	Discrete	Reliability - Other				$ (305,506)	$ 2,609	
174	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.071**	MN/AH/Black Dog Pilot Heaters	Discrete	Reliability - Other			$ (67,907)			
175	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.072**	MN/MD/STCL/BigLake Odorizer Removal	Discrete	Reliability - Other					$ (4,934)	
176	Berger	Reliability	**Gas Transmission Plant**	**E.0000404.001**	MN/SHK/INST/Blue Lake Plant Main	Discrete	Reliability - Other					$ (1,138,167)	
177	Berger	Reliability	**Gas Transmission Plant**	**E.0010073.023**	MN/MPLWD/ECLRectifier&DeepAnodeRelo	Discrete	Reliability - Other					$ (144,825)	
178	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.070**	MN/CEC/NMR/Center City Odorizer	Discrete	Reliability - Other					$ (38,158)	
179	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.081**	MN/SHK/UPGD/Blue Lake Pilot Heaters	Discrete	Reliability - Other					$ (88,540)	
180	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.084**	MN/SCL/UPGD/TBS Valve Repair	Discrete	Reliability - Other					$ (124,813)	
181	Berger	Reliability	**Gas Transmission Plant**	**E.0010076.011**	MN/EGF/Replace Line Heater at EGF T	Discrete	Reliability - Other				$ 616		
182	Berger	Reliability	**Gas Transmission Plant**	**E.0000088.001**	MN/Lake Elmo 1B/Relocate TBS	Discrete	Reliability - Other					$ (1)	
183	Berger	Reliability	**Gas Transmission Plant**	**E.0000404.002**	MN/SHK/INST/Blue Lake Plant Reg	Discrete	Reliability - Other					$ (1,232,320)	
184	Berger	Reliability	**Gas Transmission Plant**	**E.0010053.033**	MN/HST/R529 - 70th St & Manning ERX	Discrete	Reliability - Other					$ (11,170)	
185	Berger	Reliability	**Gas Transmission Plant**	**E.0010075.080**	MN/KAN/RBLD/Kandiyohi Odorizer Repl	Discrete	Reliability - Other					$ (10,015)	
186	Berger	New Business	**Gas Distribution Plant**	**D.0005014.012**	Minnesota-Gas Meter Blanket	Routine	New Business	New Meter	$ (11,976,832)	$ (21,141,906)	$ (9,619,820)	$ (14,755,425)	$ (13,124,000)
187	Berger	New Business	**Gas Distribution Plant**	**E.0010001.002**	MN - Gas New Services Blanket	Routine	New Business	New Services Routine	$ (10,596,163)	$ (9,695,958)	$ (9,482,819)	$ (9,636,729)	$ (10,009,869)
188	Berger	New Business	**Gas Distribution Plant**	**E.0010001.001**	MN - Gas New Mains Blanket	Routine	New Business	New Mains Routine	$ (8,570,169)	$ (7,258,156)	$ (5,070,730)	$ (5,454,822)	$ (6,535,037)
189	Berger	New Business	**Gas Distribution Plant**	**E.0010001.003**	MN - Gas New Business WCF	Routine	New Business - Other					$ -	$ (2,592,000)
190	Berger	New Business	**Gas Distribution Plant**	**E.0000009.027**	Southeast-Sys Reg & Mtr Inst	Routine	New Business - Other		$ 16	$ (10,738)		$ 211	$ 44
191	Berger	New Business	**Gas Distribution Plant**	**A.0006062.002**	Distribution CIAC In-Transit MN Gas	Routine	New Business - Other		$ 251,937	$ 116,660	$ 277,627	$ 114,672	
192	Berger	New Business	**Gas Distribution Plant**	**A.0006062.017**	Gas Clring Wo_s- Credits for CRS	Discrete	New Business - Other					$ 123,813	
193	Berger	New Business	**Gas Distribution Plant**	**E.0000004.084**	MN - Service Retro Fit AG Prot	Routine	New Business - Other			$ (19,990)		$ (122)	
194	Berger	New Business	**Gas Distribution Plant**	**E.0000009.006**	Newport-Reg/Meter Station Inst	Routine	New Business - Other		$ 105	$ 23,972			
195	Berger	New Business	**Gas Distribution Plant**	**E.0000009.040**	White Bear-Sys Reg & Mtr Station In	Routine	New Business - Other			$ (9,152)			
196	Berger	New Business	**Gas Distribution Plant**	**E.0000009.048**	Northwest-Sys Reg & Mtr Station Ins	Routine	New Business - Other			$ (34,171)			
197	Berger	New Business	**Gas Distribution Plant**	**E.0010033.005**	MN/STP/District Energy Reinforce	Discrete	New Business - Other			$ (399)			
198	Berger	New Business	**Gas Distribution Plant**	**E.0010033.023**	MN/NW/Inglewood Dr Phase 2 Reinforc	Discrete	New Business - Other		$ (697,443)				
199	Berger	New Business	**Gas Distribution Plant**	**E.0010033.024**	MN/NPT/CTG/M030 System Replacement	Discrete	New Business - Other		$ (27,391)		$ (142,763)	$ (6,215)	
200	Berger	New Business	**Gas Distribution Plant**	**E.0010033.025**	MN/NW/Kandiyohi Farmtap	Discrete	New Business - Other		$ (201)				
201	Berger	New Business	**Gas Distribution Plant**	**E.0010033.029**	MN/NW/New Main/Sherco Electrical Pl	Discrete	New Business - Other		$ (5,068,471)	$ (7,738)			
202	Berger	New Business	**Gas Distribution Plant**	**E.0010033.033**	MN/NPT/Cottage Grove Logistics Park	Discrete	New Business - Other		$ (276,103)	$ 26,119			
203	Berger	New Business	**Gas Distribution Plant**	**E.0010033.034**	MN/NSPM/TL0209/ECL/MAOP&Casing Proj	Discrete	New Business - Other			$ (120,015)			
204	Berger	New Business	**Gas Distribution Plant**	**E.0000009.022**	St Paul-Syst Reg & Mtr Station Inst	Routine	New Business - Other				$ 58,919		
205	Berger	New Business	**Gas Distribution Plant**	**E.0000246.001**	MN/NPT/CtgGrv/HadleyAve&IdealAve/RS	Discrete	New Business - Other					$ (1,795,230)	
206	Berger	New Business	**Gas Distribution Plant**	**E.0000246.002**	MN/NPT/CtgGrv/HadleyAve&IdealAve/NM	Discrete	New Business - Other				$ (2,071,447)	$ (422,548)	
207	Berger	New Business	**Gas Distribution Plant**	**E.0010033.007**	MN/NW/Sartell/Sartell High School	Discrete	New Business - Other				$ 134,951		
208	Berger	New Business	**Gas Distribution Plant**	**E.0010075.077**	MN/NW/Sartell/Sartell HS Reg Sta	Discrete	New Business - Other				$ (129,238)		
209	Berger	New Business	**Gas Distribution Plant**	**E.0000004.003**	MNGD New Mains-MN	Routine	New Business	New Mains Routine				$ (70,260)	
210	Berger	New Business	**Gas Distribution Plant**	**E.0000338.002**	MN/NSPM/H005/R398 RENEWAL - Mains	Discrete	New Business - Other					$ (168,913)	
211	Berger	New Business	**Gas Distribution Plant**	**E.0000465.003**	MN/SPP/INST/MRG/Meter Set Install	Discrete	New Business - Other					$ (216,086)	
212	Berger	New Business	**Gas Distribution Plant**	**E.0000469.001**	MN/NEW/EGN/INST/Dodd&RichValleyBlv	Discrete	New Business - Other					$ (584,585)	

									Actual Additions			Forecasted Additions	
Line #	**Gas Witness**	**Major Category**	**Function Class Description**	**Project ID (WBS2)**	**Project Name**	**Project Type**	**Rate Review Category**	**Major Project**	**2022**	**2023**	**2024**	**2025**	**2026**
213	Berger	New Business	**Gas Distribution Plant**	**E.0010075.041**	MN/NPT/CTG/M030 System Reg	Discrete	New Business - Other					$ (258,526)	
214	Berger	New Business	**Gas Distribution Plant**	**E.0010033.026**	MN/STP/STP/Highland Bridge Backbone	Discrete	New Business - Other		$ 1,561				
215	Berger	New Business	**Gas Distribution Plant**	**E.0010033.030**	MN/NW/Reinforcement/Delano New Busi	Discrete	New Business - Other		$ (23,215)				
216	Berger	New Business	**Gas General Plant**	**E.0010053.018**	MN/Pine Bend RNG Interconnect Proj	Discrete	New Business - Other				$ 346,669		
217	Berger	New Business	**Gas General Plant**	**E.0010053.021**	MN/NW/NewMain/Sherco ElecPlant-Comm	Discrete	New Business - Other				$ (28,818)		
218	Berger	New Business	**Gas General Plant**	**E.0000258.003**	ND/GF/GAS/Larimore Reinf/Comms	Discrete	New Business - Other					$ (14,318)	
219	Berger	New Business	**Gas General Plant**	**E.0010053.027**	MN/NW/Sartell/SartellHS RegSta/Comm	Discrete	New Business - Other				$ (3,143)		
220	Berger	New Business	**Gas General Plant**	**E.0010053.036**	MN/NEWCTG//Goebel Farms-RTU RPL	Discrete	New Business - Other					$ (160,548)	
221	Berger	New Business	**Gas Transmission Plant**	**E.0010075.030**	MN/Pine Bend RNG Interconnect/Reg	Discrete	New Business - Other		$ (274,357)	$ 323,859	$ (844,940)	$ -	
	Berger	New Business	**Gas Transmission Plant**	**E.0010073.008**	MN/Pine Bend RNG Interconnect Pipe	Discrete	New Business - Other		$ (14,046)		$ 151		
									$ (66,784,808)	$ (73,900,408)	$ (81,172,724)	$ (78,536,896)	$ (70,260,840)

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Xcel Energy

R400 Inlet Reinforcement Phase 1 Project

Ramsey County, Minnesota

Project Overview

Scope: Replace approximately 2.26 miles of 8-inch high pressure (HP) steel pipeline along Highway 96 and Old U.S. Highway 8 in Ramsey County, Minnesota with 20-inch HP steel pipeline, to tie into the inlet of regulator station R400. Installation will use both horizontal directional drilling and open trench methods. Existing pipeline will be retired in place or physically removed as required.

Pressure System: HP

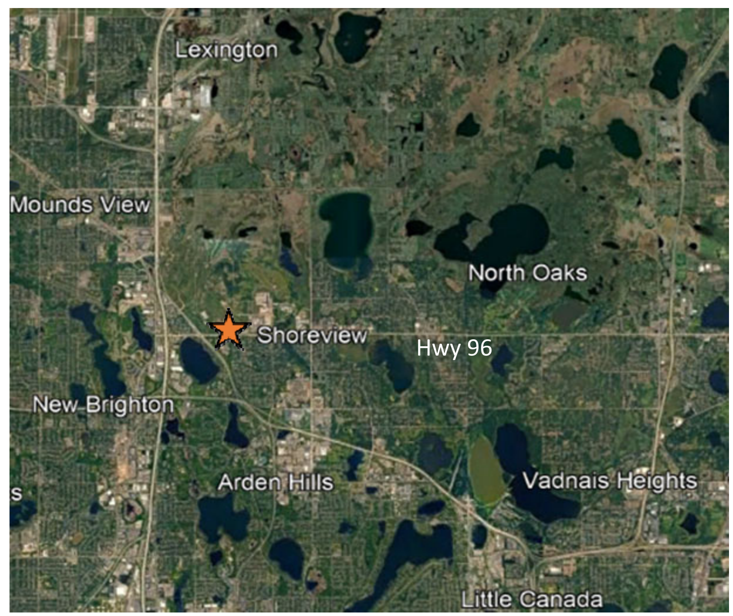
Project Status

Project Estimate Status: Complete
Design Status: Detailed design beginning October 2026
Construction: Second Quarter through Fourth Quarter 2026
In-Service Date: Planned for Fourth Quarter 2026

Project Need

Project Need: The Highway 96 HP pipeline, which supplies the R400 regulator station, is currently beyond capacity for design day peak hour conditions due to demand growth on the North Metro intermediate pressure (IP) system that has occurred over time. This project is needed to maintain minimum inlet pressure of the R400 regulator station serving the North Metro IP system.

Project Location



Project Cost

Project Cost: $18.7 million

Project Capital Expenditure Estimate: Project costs were estimated by engineering based on vendor unit pricing, historical costs of similar projects, available material costs, and expected costs per foot given the location and installation methods.

Review Process: The project is being developed, reviewed, and approved consistent with the process where there are prescribed requirements at each gate within a project's lifecycle.

R400 Inlet Reinforcement Phase 1 Project

The figure below provides a visual overview of the gas system involved in the R400 Inlet Reinforcement Phase 1 project, depicting the overall North Metro System and showing the North Metro IP system, denoted as "System H005." The pink ovals indicate the R400 regulator station and the overall project area.

North Metro System

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Gas Systems O&M Costs by Category State of Minnesota Gas Jursidiction ($ millions)					
Cost Category	**2022 Actuals**	**2023 Actuals**	**2024 Actuals**	**2025 Forecast**	**2026 Budget**
Contract/COV	$9.4	$10.0	$11.2	$11.3	$16.2
Employee Expenses	$0.6	$0.6	$1.0	$0.5	$0.5
Facility Costs	$0.1	$0.1	$0.1	$0.1	$0.1
Labor	$20.0	$21.0	$22.8	$24.7	$27.4
Materials	$4.6	$4.5	$5.8	$5.3	$4.5
Misc Other	$0.5	$0.4	$0.2	($0.9)	$1.2
Operational Credits	($6.1)	($10.3)	($7.2)	($9.4)	($9.4)
Regulatory & Other Fees	$0.3	$0.3	$0.2	$0.2	$0.3
Transportation	$3.8	$3.3	$3.4	$3.6	$3.9
Total	**$33.0**	**$29.9**	**$37.5**	**$35.3**	**$44.4**

Gas Systems O&M Costs by FERC Account State of Minnesota Gas Jurisdiction					
FERC Account	**2022 Actuals**	**2023 Actuals**	**2024 Actuals**	**2025 Forecast**	**2026 Test Year**
735.0	(128,253)	153,312	(46,440)	258,070	912,886
813.0	4	598,630	-	-	-
824.0	2	1	-	-	-
841.0	19,953	39,083	19,662	5,706	-
843.2	-	12	-	-	-
843.3	-	-	-	172	-
843.6	-	-	157	-	-
844.3	94,240	80,757	81,963	28,179	-
846.2	43	19	-	-	-
847.2	-	3	-	-	-
847.3	-	-	331	183	-
850.0	291,930	289,845	355,907	220,131	33,297
851.0	53,453	77,331	100,876	97,526	36,393
856.0	107,997	147,674	155,464	94,063	18,402
857.0	12,567	33,015	29,582	20,259	-
859.0	33	12	-	229	-
863.0	105,486	104,482	198,344	107,404	5,925
865.0	18,130	10,496	54,710	55,445	-
866.0	564	-	-	1,471	-
870.0	5,947,773	5,406,078	6,947,125	5,970,461	7,129,152
871.0	2,690,955	2,822,372	2,683,158	2,826,329	2,682,926
874.0	9,671,770	10,331,406	12,434,103	11,793,546	15,609,099
875.0	265,440	292,826	311,173	257,089	306,916
877.0	148,284	126,918	145,763	53,919	-
878.0	(3,297,875)	(6,710,668)	(1,414,768)	(4,784,695)	(5,444,107)
879.0	1,144,667	1,319,462	1,579,748	1,386,960	1,254,708
880.0	4,376,868	4,890,347	4,248,742	6,330,120	10,551,242
881.0	275	5,234	1,312	451	-
885.0	470,254	549,848	1,078,898	1,423,498	1,625,441
887.0	1,710,157	736,526	1,118,501	737,901	993,778
889.0	484,875	447,971	443,240	456,712	346,796
891.0	4,017	14,842	2,049	-	-
892.0	5,310,161	4,934,111	4,850,302	5,001,012	6,016,208
893.0	3,239,792	3,155,667	2,015,287	2,860,197	2,233,760
894.0	-	-	-	1,764	3,598
902.0	4,586	913	2,642	-	-
903.0	226	0	1,833	2,924	-
904.0	-	-	-	-	-
904.0	241,660	(45,553)	10,199	7,123	-
905.0	19	7	-	-	-
909.0	-	254	213	-	-
910.0	27	11	-	-	-
912.0	-	-	-	-	-
916.0	0	-	-	-	-
920.0	36,266	26,863	15,073	12,056	55,824
921.0	6,518	6,788	11,050	3,008	-
922.0	-	-	-	-	-
923.0	(8,033)	11,352	17,767	3,276	-
925.0	-	-	-	-	-
930.1	1,306	1,134	187	268	-
930.2	17,685	15,436	9,276	24,156	32,318
931.0	1	-	-	-	-
932.0	-	-	8,162	-	-
935.1	-	-	-	5	-
935.3	-	-	-	85	-
Total	**$ 33,043,818**	**$ 29,874,817**	**$ 37,471,591**	**$ 35,257,002**	**$ 44,404,562**