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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-23-413
Exhibit___(AEB-1)

Gas Operations

November 1, 2023

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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 following sections:

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**, undertaking **Mandated Relocations** of Gas infrastructure, and providing peaking natural gas supply from the Company's **Plants.**

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 2024, 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 2024 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 the Company's prior gas rate cases and any other orders implementing requirements for our next 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 investments in programmatic reliability and safety investments, and in our gas peaking plants. I also explain how certain cost increases, such as those related to increased labor and underground Gopher State One Call "locates" associated with our Damage Prevention program, are driven by increasing customer and system demands. 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 IV* – 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 33 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 470,000 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 9,700 miles of distribution mains and 66.4 miles of transmission pipeline, and over 491,000 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. 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, complying with all state and federal regulations, and operating and maintaining gas peaking facilities, 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 safe, reliable, and environmentally sound. PHMSA oversees the development and implementation of regulations concerning pipeline construction, maintenance, and operations. 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 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.
- 49 CFR Part 199 – programs for preventing alcohol misuse and to test gas employees for the presence of alcohol and prohibited drugs.

Historically, the State of Minnesota, Department of Public Safety, Office of Pipeline Safety (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, 2021 with a 2022 test year, in Docket No. G002/GR-21-678 (the 2022 Gas Rate Case). The Commission's Order accepting the Settlement agreement and setting rates in that docket was issued on April 13, 2023. Although the Company's gas system has not changed significantly since we filed our last rate case, the Company added 4,059 gas services and approximately 124 miles of distribution main in 2022, 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, and upgrades at our peaking plants to comply with current code, 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 2022 Gas Rate Case, there have been significant changes in industry rules, requirements, 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 and rupture detection safety standards in 2022. Additionally, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 has initiated several proposed rulemakings that will likely have a large effect on distribution assets. Under this law, PHMSA released a Notice of Proposed Rulemaking (NPRM) for Gas Pipeline Leak Detection and Repair in 2023 and has submitted another NPRM related to distribution pipeline safety initiatives to address legislative requirements based on the 2018 Merrimack Valley low-pressure distribution incident.

Q. ARE THE INDUSTRY RULES AND REQUIREMENTS DISCUSSED ABOVE GENERALLY DRIVING THE NEED FOR THIS RATE CASE?

A. Not to a large extent. 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 due to rising sales during this 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.

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 I will

[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.

discuss later in my testimony, Gas Operations' investments in this case also include projects at our peaking plants – both routine investments and discrete projects necessary to maintain operational safety and reliability and compliance with current codes – 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 400 miles of high- and medium-risk, aging, corroded, and otherwise damaged gas distribution pipeline, as well as the replacement of approximately 17,800 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 Statues. 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, 2023 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.

A. There are five 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, undertake infrastructure **Relocations** mandated by city, state, or federal authorities, and provide peaking natural gas supply from our **Plants**. 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 FIVE CORE AREAS?

A. Yes. I will discuss each in turn:

1. **Safety:** 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 base rates or the GUIC Rider.

   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. Almost 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 rights-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 recovered through the GUIC Rider beginning in 2023 so are not included in the cost of service in this rate case.

5. **<u>Plants</u>:** As I previously noted, the Company has one LNG and two propane air plants on its system to provide gas supply to its firm customers during cold weather and emergency conditions. Just like traditional gas supply that the Company procures on the open market and transports to the State of Minnesota on NNG and VGT pipelines, the Company relies on peaking supply from its LNG and propane facilities to meet design day requirements for firm customers.

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.

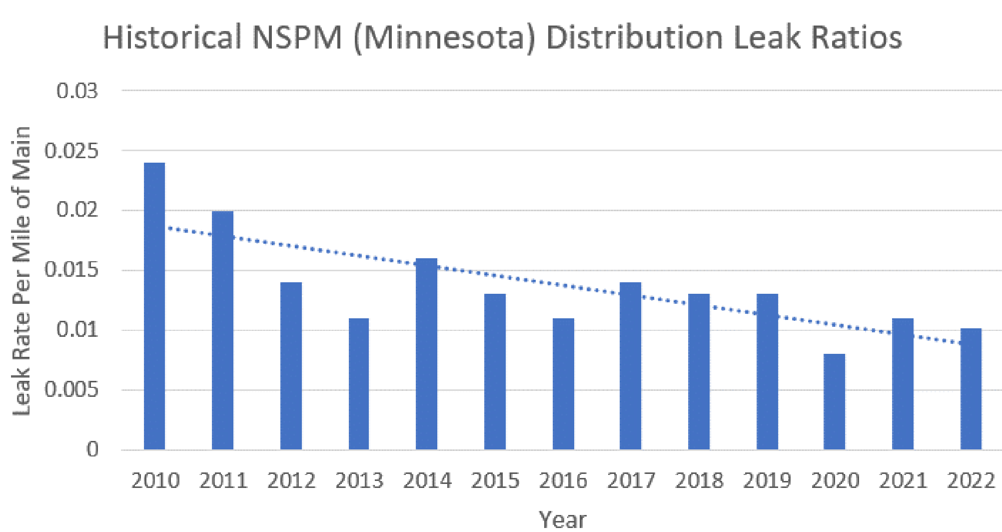
Q. CAN YOU PROVIDE AN OVERVIEW OF HOW THE COMPANY HAS ENHANCED THE SYSTEM AND CUSTOMER SERVICE?

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 60 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 2022, on a Minnesota-only basis, showing an overall decline in the past decade-plus.

Figure 1



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 2022, NSPM has renewed over 400 miles of main and approximately 17,800 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 and provide 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 2022, and 100 percent completion is forecasted in 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 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 fall into five capital budget groupings, depending on the primary purpose of the project. These groupings are based on our core work, described above: Safety, Reliability, New Customer Business, Mandated Relocations, and Plants.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION REGARDING THE TYPES OF CAPITAL INVESTMENT NEEDED IN EACH OF THESE CATEGORIES?

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

Safety: Maintaining safety requires a multi-faceted work and capital investment approach that considers the complex nature of the system and the multiple risks that face any natural gas system. 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 work on our infrastructure to reduce leaks, improve safety (such as our Inside Meter Move Out program, discussed later in my testimony), renew service mains and pipes, and the like.

Reliability: 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.

New Customer Business: 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.

<u>Mandated Relocations</u>: The Company is required to move existing infrastructure 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. Although the Company seeks contributions from the local entity where possible, the Company must invest capital to achieve these relocations and establishment of service via infrastructure at a different location. 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.

<u>Plants</u>: The Company has three gas supply peaking plants – one LNG plant (Wescott), and two propane air plants (Sibley and Maplewood). These plants are used to ensure we can meet our firm customers' demand for natural gas on those occasions where we approach Design Day conditions, and also to assist in intra-day balancing. Because these plants generally are available to provide gas to firm customers during peak conditions, the Company is able to avoid incremental pipeline capacity purchases to meet the same need. The peaking plants also provide diversity to the Company's capacity portfolio, in addition to third-party interstate pipeline capacity.

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 Christopher R. Haworth, Sangram S. Bhosale, and Michael O. Remington.

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 Haworth 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 Bhosale 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 Bhosale, the vast majority of Fleet capital additions in 2023 and 2024 support the Gas Distribution area. 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 THE WORK OF GAS OPERATIONS ON BEHALF OF CUSTOMERS?

A. As Company witness Remington 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 mitigation 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 expenditures. 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. The System Strategy and Business 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 (2021 and 2022 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, plants, and safety). Discrete projects in reliability, plants, 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, AND PLANTS THAT ARE INCLUDED IN THIS RATE CASE.

A. Table 1 below summarizes the Company's capital additions in these five areas included in the test year, 2023 forecasted additions, and a three-year trend of capital additions from 2020 to 2022 (the most recent three years of actual data):

Table 1
Gas Operations Capital Additions 2020-2024
State of Minnesota Gas Jurisdiction ($ millions)

MN Gas Additions	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
Safety	$1.3	$2.3	$1.8	$4.0	$5.6
Reliability	$13.7	$18.1	$28.2	$39.2	$37.0
New Business	$24.6	$26.3	$36.6	$31.5	$31.9
Plants	$3.9	$10.0	$53.4	$15.3	$50.1
Total	**$43.4**	**$56.7**	**$120.1**	**$90.0**	**$124.6**

Q. WHAT WERE THE PRIMARY DRIVERS OF GAS OPERATIONS' CAPITAL ADDITIONS FROM 2020 THROUGH 2022?

A. Most of the Gas Operations capital additions from 2020 through 2022 are routine investments in reliability and new customer connections, as well as large discrete refurbishment projects at the Wescott, Maplewood, and Sibley peaking plants in 2021 and 2022. These plant refurbishment projects were discussed in the Company's 2022 Gas Rate Case, and I provide further discussion in the Plants section later in my testimony.

Additionally, three large discrete reliability projects were completed during this timeframe. A reliability project in support of additional capacity in the Delano area included $8.4 million in capital additions in 2022, reinforcement of Saint Cloud and Sartell area with a $3.0 million high pressure pipeline in 2021, and $3.1 million in capacity expansion for the Becker and Big Lake area in 2021. Reliability routines also had $5.1 million in total for various reinforcement projects during the period 2020-2022.

Q. WHAT ARE THE PRIMARY DRIVERS OF GAS OPERATIONS' CAPITAL ADDITIONS IN 2023 SO FAR?

A. The 2023 forecasted capital additions are estimated at $90.0 million, an increase compared to 2020 and 2021 but a reduction compared to 2022, due to the variability of investments. The primary drivers for this variance in capital additions from 2022 to 2023 are in the areas of Reliability, with smaller investments in our Wescott LNG and Sibley and Maplewood Propane Air facilities. First, in 2023 the Company is forecasting $39.2 million in capital additions for reliability compared to $13.7 million in 2020. Several large discrete reliability projects comprise this total increase, including the Meter Module Replacement program ($22.1 million), which I discuss in detail in the Reliability section below, the Delano project I mentioned above, which also had capital additions in 2023 ($2.3 million), and a reinforcement project in Woodbury ($1.2 million). Second, the Company is making routine and discrete investments at the Wescott, Sibley, and Maplewood gas peaking plants, with many of the projects related to closing out the larger refurbishment project that were largely completed in 2022. In addition, new business additions increased from $24.6 million in 2020 to $31.5 million forecasted for 2023, driven primarily by higher forecasted routine additions. I discuss these investments in more detail later in my Direct Testimony.

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

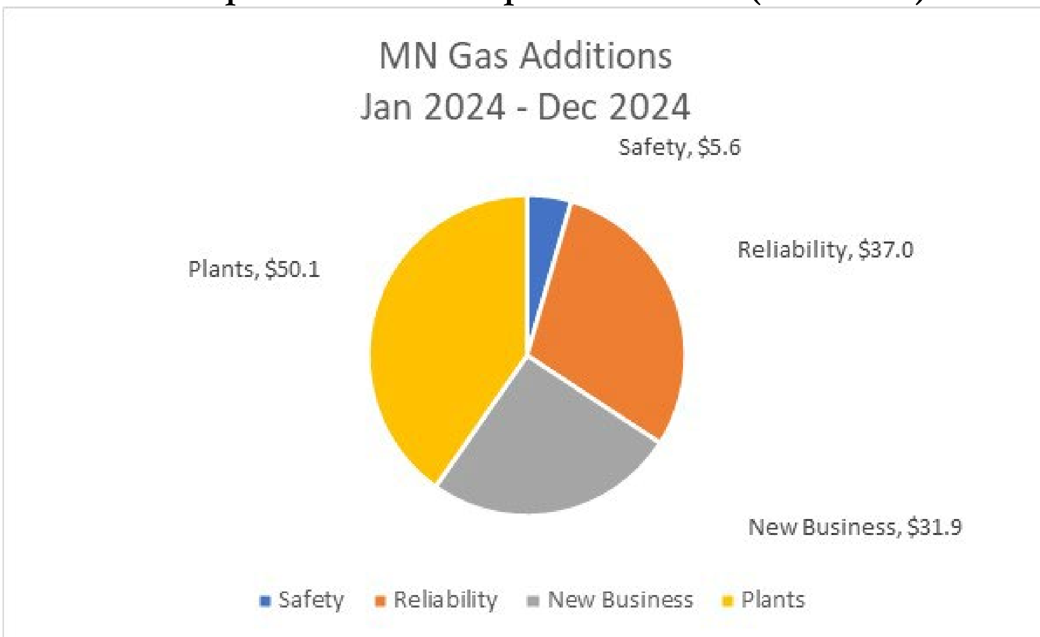
A. Table 1 illustrates that capital investments can vary significantly on a year-to-year basis depending on the specific work that is necessary to meet the needs of both our customers and our business. In certain years, Gas Operations' capital investments may be lower for a variety of reasons, including the level of customer new business requests or few 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, investments in specific peaking plant refurbishment projects were a significant driver of Gas Operations capital additions in the 2022 test year in our last gas rate case, but we did not place plant investments of that size in service in 2023. As I will discuss further in the following section, fire detection and suppression upgrades are being undertaken at the Maplewood and Wescott plants in 2024. While these projects are a driver of Gas Operations capital additions in the 2024 test year, these amounts do not reflect ongoing expenditure levels, but rather reflect capital additions for specific initiatives being placed in service in the test year.

2. Overview of Gas Operations' 2024 Capital Investments

Q. WHAT ARE GAS OPERATIONS' CAPITAL FORECASTS FOR 2024 BY CAPITAL BUDGET GROUPING?

A. In addition to Table 1 above, Figure 2 below illustrates the Company's forecasted Gas Operations 2024 additions in the 2024 test year.

Figure 2
Gas Operations 2024 Capital Additions ($ millions)



Q. How do Gas Operations' capital additions for the 2024 test year compare to historic trends?

A. Capital additions for 2024 are estimated at $124.6 million, which is 38 percent higher than the 2023 forecast. The primary reason for this increase is an increase in the new capital additions related to the peaking plants in 2024, and the timing of those large discrete, multi-year projects.

Q. What are the major capital investments in the Company's 2024 test year?

A. These major capital investments include fire detection and suppression system upgrades at the Maplewood and Wescott peaking plants, replacement of truck unloading infrastructure at the Sibley peaking plant, replacement of existing meter modules for drive-by meter reading and continuation of our inside meter move out program, and certain discrete capacity projects to ensure firm customers are served during design day conditions. These individual projects and the associated capital additions for each are summarized in Table 2 below.

Table 2
2024 Gas Operations Major Capital Projects
State of Minnesota Gas Jurisdiction ($ millions)

Capital Category	Project Name	2024 Test Year
Plants	Maplewood Fire Detection/Suppression System Upgrades	$26.7
Reliability	Meter Module Replacement Program	$21.6
Plants	Wescott Fire Detection/Suppression System Upgrades	$12.6
Safety	Inside Meter Move Out	$3.6
Plants	Sibley Truck Unloading	$2.9

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 2024

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

A. The purpose of this section is to provide more detail regarding the key capital additions for discrete and routine projects for Gas Operations during the 2024 test year. For purposes of testimony, we sought to describe capital investments totaling at least 80 percent of the capital additions being placed in service in 2024. 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 2024 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
Gas Operations Reliability Capital Additions
Routines vs. Discrete Projects ($ millions)

Project Name	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
Routine	$4.1	$5.6	$7.0	$6.2	$7.1
Discrete	$9.6	$12.5	$21.2	$33.0	$29.9
Total	**$13.7**	**$18.1**	**$28.2**	**$39.2**	**$37.0**

Q. PLEASE DESCRIBE THE DISCRETE RELIABILITY PROJECTS THAT WILL BE ADDED IN 2024.

A. Table 4 below lists the key discrete reliability projects that will be in-serviced in 2024. In addition, Table 4 contains a brief description of each reliability project. Projects over $1 million will be described in further detail in separate sections below. As shown, the large increase in the discrete reliability category beginning in 2022 is driven primarily by the Meter Module Replacement program, which will be discussed in detail below.

Table 4
Discrete Reliability Plant Additions ($ millions)

Project Name	Description	2024 Test Year
Meter Module Replacement	Replacement of current automated meter reading (AMR) technology.	$21.6
Forest Street Bridge Crossing Project	Relocate 500 feet of main that is currently suspended from the Forest Street Bridge to run under Phalen Boulevard in Saint Paul, MN.	$1.8
Saint Michael Reinforcement	Replace 11,600 feet of 4-inch pipeline with 6-inch pipe in Saint Michael, MN.	$1.5
Lake Elmo Project	Relocate existing Lake Elmo, MN town border station (TBS) facilities.	$0.7
SCADA Component Replacement	Replace certain remote terminal unit computer equipment that will no longer be supported by manufacturer, including software, hardware, and electrical upgrades.	$0.7
Faribault TBS Project	Rebuild the Faribault TBS and relocate it south of Highway 60 in Faribault, MN, and extend 6-inch HP main to the new TBS location.	$1.0
Sauk Rapids Project	Remove the existing below ground regulator station located on 2nd Avenue South and install a new above-ground regulator station in Sauk Rapids, MN.	$0.6
R361 Regulator Station	Remove regulator station R361 in West Saint Paul, MN, and install a new district/monitor station at the same location.	$0.4
R1008 Reinforcement Project	Rebuild the existing regulator station R1008 to serve a new business expansion of approximately 1,700 new homes in Shakopee, MN.	$0.4
Reliability – Other	Various projects in support of system reliability.	$0.7
Total		**$29.9**

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 many of the projects listed in Table 4 above, are identified as a result of the Company's annual system modeling. The Company's system capacity modeling is described further below.

Q. HOW IS THE COMPANY'S SYSTEM CAPACITY MODELING PERFORMED?

A. Computer-aided system modeling allows for accurate simulation of the Company's system from the numerous supply interconnects, through the pipeline networks, to customer delivery points. The Company's Geospatial Information Systems (GIS) contains the most current records of pipe and facilities, with important system attributes that include pipe material, pipe diameter, date of installation, and operating pressure. Through the use of GIS, Supervisory Control and Data Acquisition (SCADA) data, and user input information, the Company is able to create system models with hydraulic modeling software called Synergi®. The modeling software then simulates transmission and local distribution systems to represent pressure and flow conditions based on design day temperatures and firm customer growth. The software therefore identifies, predicts, and helps address the system's operational challenges, enabling day-to-day efficiency of gas distribution and transmission networks.

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 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 DAY TEMPERATURES FOR EACH REGION IN THE COMPANY'S SYSTEM?

A. Table 5 below provides the peak hour temperatures by operational area that 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 design hour temperatures.

The peak hour temperatures were last modified after a severe cold weather event in the region in January 2019, during which severe cold weather over a sustained period stressed the Company's ability to maintain reliable service for our firm natural gas customers. After reviewing the weather data from the 2019 cold weather event, NSPM incorporated new peak hour temperatures into its gas capacity modeling throughout its service territory. These updated temperatures are reflected in Table 5 above and are factored into our current peak day and 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. Discrete Reliability Projects

i. Module Replacement

Q. WHAT IS THE MODULE REPLACEMENT PROGRAM?

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

Q. WHY DID THE COMPANY ELECT TO IMPLEMENT DRIVE-BY METER READING?

A. The Company considered several options to prepare for the expiration of the gas meter read service agreement with CellNet, including transition to manual meter reading of legacy diaphragm meters, or pursuing migration to advanced metering infrastructure (AMI) via a module replacement program (with legacy meters). The best option was the use of the Itron Drive-By AMR solution, with financial benefits that exceeded those of the alternatives.

While the Company reviewed an AMI option, the decision to use the Itron Drive-By AMR solution was based on proven technology the Company uses in other areas. Additionally, this option was less complex to execute and reduced costs. This solution also provides flexibility for future transition to AMI without meter/module replacement. While the Company is transitioning to AMI on the electric side, the benefits of AMI are not equally applicable to natural gas service. For example, time-of-use electric rates can provide significant overall benefits on the electric side, but those benefits do not translate in the same manner for natural gas service. As such, the Company is implementing the module replacement program to enable drive-by meter reading.

In addition to AMR being a cost-effective option, in this case, it provides benefits relative to maintaining flexibility rather than reliance on third-party equipment and service. The drive-by gas meter reading solution we have adopted is the preeminent industry drive-by meter reading solution and is compatible with gas meter products in use by the Company from multiple manufacturers. Additionally, the replacement of the current fixed network AMR technology expands the Company's drive-by gas meter reading solution to the Brainerd area. The Company will continue to assess ways to reduce emissions, and the fleet vehicles for drive-by meter reading will be considered in the Company's overall assessment of its fleet and potential conversion to electric vehicles.

Q. WAS THIS PROGRAM IDENTIFIED IN THE COMPANY'S LAST GAS RATE CASE?

A. Yes. The Module Replacement program was introduced in our 2022 Gas Rate Case, with the expectation that work would begin during the 2022 test year. During 2022, the Company revised its forecast due to global supply chain issues that were impacting delivery of the modules. This resulted in the majority of the work that was planned for 2022 to be moved into 2023 and 2024. Because the Company must complete this work before the CellNet contract expires at the end of 2025, and because the supply chain challenges are still present, the Company has worked closely with the manufacturer to align the delivery schedule with our deployment schedule. Work on the project began in 2023 and the module replacement program is expected to conclude in 2025.

Q. WHAT IS THE STATUS OF THE COMPANY'S MODULE REPLACEMENT PROGRAM?

A. Under this program, the Company expects to replace approximately 479,000 modules. The Company selected the module vendor in September 2022 and the field work is being completed using a combination of internal and contract resources. The Company anticipates replacement of 198,100 modules in 2023, and the forecast reflects anticipated replacements of 185,200 modules in 2024, with the remainder to be completed in 2025.

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

A. The forecasted capital additions for 2024 are approximately $21.6 million, based on the current project schedule. Cost estimates were developed based on the number of modules to be exchanged, the number of meters to be exchanged, and the related equipment necessary, and the Company's current estimates for this equipment.

Q. WHAT DO YOU CONCLUDE REGARDING THE MODULE REPLACEMENT PROGRAM?

A. The costs of this program should be approved as the work is necessary because the agreement with the Company's meter reading provider will expire December 31, 2025, and the current technology will no longer be supported. The drive-by meter reading solution is a cost-effective option providing benefits relative to maintaining flexibility, is compatible with gas meter products in use by the Company from multiple manufacturers and will expands the Company's drive-by gas meter reading solution to the Brainerd service area.

ii. Forest Street Bridge Crossing

Q. WHAT IS THE FOREST STREET BRIDGE CROSSING PROJECT?

A. The Forest Street Bridge Crossing project will relocate approximately 500 feet of main that is currently suspended from the Forest Street Bridge to instead run under Phalen Boulevard in Saint Paul, Minnesota. Exhibit___(AEB-1), Schedule 4 contains a map and overview of this project.

Q. WHY IS THIS PROJECT NEEDED?

A. The existing 12-inch steel pipe, installed in 1981, is suspended from the Forest Street bridge over Phalen Boulevard. This configuration does not allow for inspection and maintenance access unless traffic is shut down on Forest Street and Phalen Boulevard. In addition, the city of Saint Paul has plans to replace the bridge. The Company will coordinate with the city to complete this pipeline work before the city's bridge construction work begins.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE FOREST STREET BRIDGE CROSSING PROJECT.

A. The project will remove the existing pipe from the Forest Street bridge and perform directional boring to install a new 12-inch coated steel pipe under Phalen Boulevard as a replacement. This will allow the Company unobstructed access for future inspections and maintenance activities of the pipeline. Removal of the pipeline from the existing bridge will also allow the city of Saint Paul to complete its planned construction work on the bridge without also having to consider integration of gas system infrastructure.

iii. Saint Michael Reinforcement Project

Q. WHAT IS THE SAINT MICHAEL REINFORCEMENT PROJECT?

A. The Saint Michael Reinforcement project will replace 11,600 feet of 4-inch IP pipeline with 6-inch pipe along Highway 35 in Saint Michael, Minnesota. Exhibit___(AEB-1), Schedule 5 contains a map and overview of this project.

Q. WHY IS THIS PROJECT NEEDED?

A. The average annual firm customer count in the Saint Michael area is projected to increase 65 percent between 2022 and 2024. Due to growth in the area, inlet pressure to the regulator station serving Saint Michael is reaching its minimum design criteria, requiring a project to increase pressure and capacity at the regulator station.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK INVOLVED IN COMPLETING THE SAINT MICHAEL REINFORCEMENT PROJECT.

A. This project will consist of open trenching along the north side of Highway 35 to install 11,600 feet of 6-inch pipeline. The new pipeline will be tied into existing 6-inch pipe on the west end and 4-inch pipe on the east end, approximately at 7370 30th Street NE. Existing 4-inch pipe will be abandoned in place. This will provide sufficient capacity in the pipeline for the Saint Michael growth.

iv. Reliability – Other

Q. PLEASE DESCRIBE THE RELIABILITY – OTHER PROJECTS.

A. In addition to the discrete reliability projects mentioned previously the Company will also perform other projects to help ensure system infrastructure reliability to serve Minnesota customers. These projects include replacements of above ground regulator stations, rebuilding of regulator stations, and reinforcement projects.

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. 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.

Q. HAVE NEW RELIABILITY PROJECTS BEEN IDENTIFIED IN THE COMPANY'S MOST RECENT MODELING?

A. Yes. For example, based on the Company's recent modeling, two notable projects have been identified for anticipated completion in 2024. However, due to the timing of preparing the forecast for this rate case, they were not included in the 2024 test year. These include reliability projects in Woodbury and Cottage Grove. The Woodbury project will be required to provide sufficient capacity for anticipated growth in the Woodbury area in 2024-2025 and is estimated at approximately $1.4 million. We will need to install approximately 5,000 feet of 8-inch PE new main and a new distribution station feeding into future housings and commercial customers. The Cottage Grove project requires us to install 2 miles of main and a new distribution station in order to provide more than 100 MCFH (thousand cubic feet per hour) of sufficient load for the 2024 new developments in Cottage Grove. This project is estimated at approximately $1.3 million. While these projects were not included in the test year budget when it was developed for this case, the emergence of these projects illustrates that while the scope and timing of some projects may change based on updated information, new projects may also be identified as necessary. This regular review helps ensure that the Company is making the right investments in the gas system to benefit our customers based on the most current information.

b. Routine Reliability Projects

Q. PLEASE DESCRIBE THE INVESTMENTS IN ROUTINE RELIABILITY OF APPROXIMATELY $7.1 MILLION THAT THE COMPANY ANTICIPATES IN 2024.

A. There are several items that are included in the reliability routines for 2024, and the costs in 2024 are primarily related to two types of work. First, $3.7 million was budgeted in the reliability routine to 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, $2.8 million was budgeted in the reliability routine for 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. WHAT FACTORS HAVE IMPACTED THE COMPANY'S FORECASTED RELIABILITY ROUTINE ADDITIONS FOR THE TEST YEAR?

A. Projects that are funded under routines are generally not defined until the current year; the budget is determined based largely on historical actuals. More specifically, routine budgets are based on a two-year historical average (2021 and 2022 actuals) plus corporate escalation (inflation) factors. Additionally, the Company installed over 20 new pressure monitoring devices in Minnesota after the extreme cold weather event in 2019 that I described earlier in my testimony. These devices specifically monitor system delivery pressures and the pressure at the tail-ends of our system to ensure customer reliability. All of these factors are considered in our determination of routine reliability projects necessary each year.

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 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 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 6 below identifies the Safety plant 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 6
Discrete Safety Capital Additions ($ millions)

Project Name	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
Inside Meter Move Out	$0.0	$0.0	$0.1	$1.7	$3.6
Tools and Equipment	$0.5	$1.4	$1.3	$1.6	$1.3
Capitalized Locating Costs - Gas	$0.8	$0.8	$0.5	$0.6	$0.8
Total	**$1.3**	**$2.3**	**$1.8**	**$4.0**	**$5.6**

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 significant 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 THE COMPANY'S LAST GAS RATE CASE?

A. Yes. The Inside Meter Move Out program was introduced in our 2022 Gas Rate Case, and initial work on the project began in 2022. This program is expected to be largely completed during the period 2023-2028. 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. Furthermore, 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. 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.

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

A. There are approximately 19,200 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 WITHIN ITS SYSTEM?

A. NSPM began the Inside Meter Move Out project 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. NSPM began relocating meters to the outside in 2022. In 2023, the Company estimates to renew and replace approximately 220 meters, and in 2024 we estimate 570 meters will be moved out. The Company anticipates the additional 5,600 meters will be moved out in future years, and the project is expected to be completed in 2028. Global supply chain issues have impacted delivery of various materials, which in turn has impacted the Company's ability to relocate meters according to initial project plans, especially in 2022. Due to these ongoing supply chain issues, the Company revised its forecasts for the number of meters to be moved in 2023 and 2024 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 2023 and $3.6 million in 2024. The estimated capital cost associated with relocating a meter outside is approximately $6,400, comprised of an estimated $5,875 when a service renewal is required and $525 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 570 meters, equates to our 2024 capital expenditure budget of $3.6 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. 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. 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 2024, the Company is forecasting $1.3 million in tools and equipment investments, which is consistent with amounts in recent years, and less than the 2023 forecast. This forecast is based on historical spend plus escalation.

c. 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 2024, the Company forecasts incurring approximately $0.8 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. During that initial call, information such as address, customer contact information, building type, and any available load data is collected by the Company and compiled into a standardized form. That data 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 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 but cannot necessarily predict exactly when those calls will be received.

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE NEW BUSINESS CATEGORY FOR 2024?

A. As shown in Table 7 below, all new business plant additions in 2024 are budgeted as routines, totaling $31.9 million, as compared to total new business plant additions of $24.6 million in 2020, $26.3 million in 2021, $36.6 million in 2022, and $31.5 million in 2023.

Table 7
New Business Plant Additions
Routines vs. Discrete Projects ($ millions)

Project Name	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
Routine	$24.5	$25.3	$31.0	$31.7	$31.9
Discrete	$0.1	$1.0	$5.7	($0.2)	$0.0
Total	**$24.6**	**$26.3**	**$36.6**	**$31.5**	**$31.9**

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 2024 test year new business routines forecast is based on the average of historical actuals from 2021 and 2022 escalated by the corporate inflation rates. Further, inputs and assumptions regarding inflation factors are used to determine the assumed cost increases or decreases. These inflation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates, and bargaining labor increases.

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 $31.9 million in plant additions. From January 1, 2022 through December 31, 2022, the Company's actual plant additions for the new business routines was $31.0 million. This increase between 2022 to 2024 is reasonable considering 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.

4. Plants

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

A. The Company owns and operates three above-ground peaking facilities, including the Wescott LNG plant and the Sibley and Maplewood Propane Air plants. These plants essentially store liquefied natural gas or propane that can be vaporized and injected into the system to help meet firm customer requirements on the coldest winter days. These plants support service to our customers by reducing the need for additional pipeline capacity. These peaking plants are largely capacity resources and are designed to be utilized on a limited basis to meet demand for our firm customers when needed.

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE PLANTS CATEGORY OF CAPITAL INVESTMENT?

A. Capital projects included in this category include projects to maintain the Company's Wescott, Sibley, and Maplewood peak-shaving plants to ensure plant safety and reliability and compliance with state and federal codes. The capital costs in the Plants category are divided between routine work and discrete projects. Routine projects, typically totaling less than $300,000 each, are budgeted to perform routine capital maintenance. Discrete projects include larger investments related to equipment refurbishment or replacement costs.

Q. WHAT ARE THE PLANTS CAPITAL ADDITIONS FOR 2020 THROUGH THE 2024 TEST YEAR?

A. Table 8 below shows the total Plants investments, divided between routine and discrete projects.

Table 8
Gas Operations Plants Capital Additions
Routines vs. Discrete Projects ($ millions)

Project Name	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
Routine	$0.3	$1.1	$5.7	$1.4	$1.7
Discrete	$3.6	$8.9	$47.7	$14.0	$48.4
Total	**$3.9**	**$10.0**	**$53.4**	**$15.3**	**$50.1**

Q. WHAT TYPES OF INVESTMENTS ARE INCLUDED IN THE PLANTS CATEGORY IN THIS CASE?

A. The peaking plant investments include projects that have been planned during the course of the Gas Operations annual budgeting process. These include both routine investments as well as discrete projects necessary to maintain operational safety and reliability and compliance with state and federal codes. For the 2024 test year, the primary portion of the discrete in-service projects are related to fire detection and suppression system upgrades at the Wescott and Maplewood plants, which were identified as a future need in our 2021 overall plant assessments. Below, I provide a description and background information on the peaking plants, provide details related to the discrete projects at the plants in the 2024 test year, including the Wescott and Maplewood fire detection and suppression upgrades and other capital projects, and provide support for the routine capital additions in the 2024 test year.

Q. YOU MENTION THE FIRE DETECTION AND SUPPRESSION SYSTEM UPGRADES AT THE WESCOTT AND MAPLEWOOD PLANTS. IS THE COMPANY COMPLETING SIMILAR WORK AT THE SIBLEY PLANT?

A. Yes. Fire detection/suppression system upgrades are also planned for the Sibley plant. The Company anticipates implementing a tank mounding fire suppression system at Sibley, consistent with the tank mounding system that the Company is implementing at the Maplewood plant as I describe in the following sections. Because the fire detection/suppression upgrades at the Sibley plant will not be in service in 2024, they are not part of the requests in this case and are not separately described in detail below.

a. Peaking Plant Descriptions and Background

Q. PLEASE DESCRIBE THE WESCOTT PLANT.

A. The Wescott LNG plant, built in the 1970s, is located in Inver Grove Heights, Minnesota, and consists of two storage vessels capable of storing approximately 26 million gallons of LNG. During non-winter months, the Company purchases natural gas, which is delivered to the plant. The Company cools down the natural gas to approximately -260 F until it turns into a liquid form where it is stored in the tank. This process is known as liquefaction. The gas is then stored in a liquefied state until it is needed during the heating season, when it is vaporized and injected back into the distribution system.

During winter months, Wescott is utilized as a peak-shaving resource to supplement pipeline capacity during peak demand conditions. When the plant is dispatched, the reverse process, known as vaporization, occurs, where the LNG is heated until it turns back to its original gaseous form and is injected into the Company's distribution system, where it is delivered to our customers.

Q. PLEASE DESCRIBE THE SIBLEY AND MAPLEWOOD PROPANE PLANTS.

A. The Sibley Propane Air peaking plant is located in Mendota Heights, and the Maplewood Propane Air peaking plant is located in Maplewood. Both plants were built in the 1950s. Propane is delivered in its liquid state via truck to Sibley and Maplewood and is stored at the plants until needed. These two facilities combined store 2.6 million gallons of propane. When dispatched during winter months, the Company blends the propane with air and injects the gas into the distribution system where it is blended with natural gas and ultimately delivered to our customers. Like Wescott, the Sibley and Maplewood peaking plants are primarily used to support gas supply requirements during peak demand conditions.

Q. WHY ARE THESE PEAKING PLANTS IMPORTANT TO THE SYSTEM?

A. These three peak-shaving plants ensure we can meet our firm customers' needs as we approach Design Day conditions, and there may potentially be economic dispatch at the Wescott plant.[2] Although these conditions do not regularly occur, the peaking plants are still important to design day plans. Wescott can deliver 156,000 dekatherms per day (Dth/d) and Sibley and Maplewood, combined, are capable of delivering an additional 90,000 Dth/d. The ability of these plants to provide gas to customers during peak demand conditions, enables the Company to avoid incremental pipeline capacity purchases to meet the same need.

Q. CAN YOU PROVIDE A HIGH-LEVEL SUMMARY OF THE REFURBISHMENT PROJECTS THAT WERE RECENTLY COMPLETED AT THE PEAKING PLANTS?

A. Yes. As discussed in our 2022 Gas Rate Case, routine testing at the Wescott plant in late 2020 and early 2021 resulted in an unplanned release of natural gas to the atmosphere. As a result, the Company ceased operations at Wescott, as well as Sibley and Maplewood, so that we could review the vaporization

[2] *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on impacted Minnesota Natural Gas Utilities and Customers*, Docket No. G999/CI-21-135, ANNUAL REPORT (August 1, 2023).

processes at those plants. Detailed plant assessments conducted by Company personnel, as well as an independent review of the plants by third-party engineering consultants, identified necessary peaking plant refurbishment and remediation projects. These projects included control system overhauls, valve replacements, relief system modifications, and life safety system upgrades at all the plants, as well as vaporization equipment and associated system refurbishments at the propane plants.

The refurbishment and remediation projects prioritized investments and testing critical to resume vaporization at the plants, but also identified renewal work that would be needed but could be completed after the plants returned to service. The Wescott plant was brought back online for vaporization in December 2021, and the Maplewood and Sibley plants resumed regular operations in January 2022. The vast majority of discrete Plants capital additions in 2022 related to the primary phases of these refurbishment projects, with the fire detection/suppression system work to follow.

Q. DID THESE INVESTMENTS IN THE PEAKING PLANTS IMPROVE THEIR OPERATIONAL LIVES?

A. Yes. The investments at the plants extended their operational life expectancy, enabling them to serve customers beyond their then-current lives. Company witness A. Johnson explains in her Direct Testimony that the Company has asked the Commission to adjust the depreciation for the plants to align with the lengthened service lives of all three peaking plants to December 2041.

b. Peaking Plant Discrete Projects

Q. WHAT CAPITAL COSTS DO YOU SUPPORT IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I support the discrete capital additions at the peaking plants in 2023 and in the 2024 test year. Table 9 below identifies the key capital projects with over $1 million in capital additions in the 2024 test year. I provide additional information on these projects in the following sections. In addition, Exhibit___(AEB-1), Schedule 6 identifies all discrete Plant projects included the 2023 and 2024 forecast and budget, along with a summary description of each project. As I noted earlier in my testimony, many of the small discrete projects addressed in Schedule 6 relate to closing out 2021-2022 refurbishment projects.

Table 9
Capital Additions Peaking Plants ($ millions)
Discrete Projects over $1 million in 2024

Project Name	2024 Test Year
Maplewood Fire Detection/Suppression Upgrades	$26.7
Wescott Fire Detection/Suppression Upgrades	$12.6
Sibley Truck Unloading Station	$2.9
Maplewood Air Dryer	$1.5

Q. ARE THERE ANY PLANT-SPECIFIC INVESTMENTS IN INFORMATION TECHNOLOGY IN THIS CASE?

A. Yes. Any physical plant device modifications at Wescott, Maplewood, or Sibley that require mechanical and electrical updates require integration into the plant control systems. This can include updates to naming conventions and operational data, device interfaces, and programmable logic controllers, as well as upgrades to emergency shutdown safety systems and dependent hardware. A component of the overall plant refurbishment projects was the replacement of the SCADA system for the peaking plants with a new Delta V solution in-serviced in 2022, with additional implementations in 2024 to align with additional, subsequent plant investments. Many of the projects listed in the table above also require integration with the Delta V system. Delta V upgrades are included in the Technology Services budget, with capital additions in the 2024 test year supported in the Direct Testimony of Company witness Remington.

i. Fire Detection and Suppression Projects

Q. WHAT DO YOU DISCUSS WITH RESPECT TO THE FIRE DETECTION AND SUPPRESSION PROJECTS AT THE COMPANY'S PEAKING PLANTS?

A. Overall, I provide support for the capital investments in fire detection and suppression systems at the Maplewood and Wescott peaking plants, which total $26.7 million and $12.6 million, respectively, of capital additions for the 2024 test year. As noted above, the fire detection/suppression work at the Sibley plant will not be in service in 2024 and is not part of the requests in this case. I begin by providing an overview of what fire detection/suppression systems are and how they have functioned at the Company's Peaking Plants (generally speaking). In my testimony, I support the overall upgrades to the fire detection/suppression systems as a whole, but I also discuss the fire water systems separately where necessary, distinguishing the fire water systems from the fire detection capabilities at the plants. I also provide additional discussion of the Company's process for identifying the need for upgrades of the Plants' fire detection/suppression systems, as well as the work with contractors to develop an appropriate scope of work and the identification and consideration of alternatives to completing this work. I then address, in turn for each plant, the specific Maplewood and Wescott fire detection/suppression system work anticipated to be in service in the 2024 test year.

(a) *Overview of Fire Detection/Suppression Upgrades*

Q. PLEASE PROVIDE A HIGH-LEVEL DESCRIPTION OF HOW THE EXISTING FIRE DETECTION AND SUPPRESSION SYSTEMS AT THE PLANTS HISTORICALLY FUNCTIONED.

A. The existing fire detection and suppression systems at each of the plants were original to the plants – late 1950s for Sibley and Maplewood, and 1970s for Wescott. The purpose of these systems is to identify fire potentials, and to provide fire curtains and cool tanks in the event of a fire. The systems also work to safely shut down the plant in the event of fire.

The fire water system at the Wescott LNG plant has consisted primarily of a network of underground piping and hydrants that is supplied by a fire pump that draws a water supply from a well. The underground firewater system piping supplies hydrants, monitor nozzles, some fire sprinkler systems and exterior water curtain systems. The historical fire water system is currently interconnected with the neighboring Flint Hills Resources. In addition to the fire water system, the plant is also equipped with gas, flame, heat, and smoke detection equipment throughout the plant which is tied into a Det-Tronics Eagle Quantum Premier (EQP) safety system controller located in the control room.

The Maplewood Propane Air, or liquefied propane gas (LPG), plant has similar fire water and gas detection equipment as the Wescott LNG plant with a single municipal water supply source versus an independent well. The Sibley Propane

Air plant is similar to Maplewood but relies on fire department connections outside of the plant to bring water into the existing firewater system.

Q. WHAT CODES GUIDE THE COMPANY'S FIRE DETECTION AND SUPPRESSION INVESTMENTS AT THE PLANTS?

A. The codes that govern the fire detection and suppression systems at the plants are the United States Department of Transportation Pipeline Safety Regulations, including National Fire Protection Association (NFPA) codes and standards incorporated by reference (IBR). These IBRs are the primary code governing documents:

- NFPA 59 – *Utility LP-Gas Plant Code,* for Maplewood and Sibley LPG plants; and
- NFPA 59A – *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG),* for Wescott.

NFPA 59 provides safety requirements for the design, construction, location, installation, operation, and maintenance of refrigerated and non-refrigerated utility gas plants. NFPA 59A provides fire protection, safety, and related requirements for the location, design, construction, security, operation, and maintenance of LNG plants. These governing documents also include numerous other NFPA reference requirements. I discuss how current code provisions guided decision-making at the Plants in more detail below.

Q. PLEASE PROVIDE AN OVERVIEW OF THE ASSESSMENT OF THE EXISTING FIRE DETECTION/SUPPRESSION SYSTEMS AT THE PLANTS.

A. As discussed in the Company's 2022 Gas Rate Case, in 2021 and 2022 the Company conducted a comprehensive investigation to identify the necessary refurbishment at Wescott and conducted a similar review of the Sibley and Maplewood systems to ensure safety at those plants. These comprehensive reviews also proactively identified investments that would enhance reliability and improve safety systems. The comprehensive investigation included assessment of fire detection and suppression systems to determine the status of existing equipment and systems in relation to current pipeline safety regulations and NFPA codes and standards.

The existing fire detection/suppression systems at each plant were initially assessed as part of the comprehensive studies at each of the plants conducted in 2021 to determine the needs of the plants and develop project plans to address those needs. For purposes of returning to vaporization, the Company's assessors determined that the fire detection and suppression systems at each plant conformed with contemporaneous requirements from installation. Additionally, fire suppression system testing and work with local authorities having jurisdiction (known as AHJs, e.g., fire departments) ensured appropriate emergency response plans were in place to return the plants to service while the necessary modernization projects were completed. Overall, the 2021 assessments utilized a structured and systematic technique for system examination and risk management, enabling prioritization of necessary investments identified by those studies to first complete projects critical to safely resuming vaporization at the plants. As such, the Company was able to conduct testing and ultimately bring the plants back online in the 2021-2022 timeframe.

However, these proactive studies also assessed what broader investments would be necessary to refresh the older plants, align with more recent codes such as NFPA 59 and NFPA 59A, and support the functionality of these plants on behalf of customers for decades to come. Much of the plant modernization investments following these studies were completed in 2022 and 2023; the fire detection/suppression system upgrades were planned to follow in a phased approach and are included in this case with in-service dates beginning in 2024.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ABOUT HOW THE STUDIES OF THE EXISTING FIRE DETECTION/SUPPRESSION SYSTEMS AT THE PLANTS WERE CONDUCTED?

A. Yes. As we also discussed in our 2022 Gas Rate Case, the Company engaged engineering design contractor Campos EPC to assist with the initial investigatory work. The Company, in conjunction with Campos, conducted an overall review of the plants (along with other experts) to identify any necessary upgrades and develop a plan for implementation. Campos in turn engaged a nationally recognized expert in fire detection/suppression system engineering and code compliance (Jensen Hughes) for this effort. The objective was to evaluate the existing fire detection/suppression systems to identify any work that would be necessary to maintain compliance with all current NFPA codes and standards. This holistic approach included a gap analysis, system and equipment reviews, and hydraulic modeling. The Company also worked with local fire chiefs, the AHJs as defined by the current NFPA, to develop plant support plans while the studies were conducted and to weigh in on the Company's assessments and phased approach for implementation. The final assessments of the existing fire detection/suppression system were completed in December 2021. The primary conclusions of these studies are discussed in the individual plant sections below.

Q. HOW DID THE COMPANY PROCEED ONCE THE NECESSARY FIRE DETECTION/SUPPRESSION STUDIES WERE COMPLETED?

A. The Company then worked with Campos to develop comprehensive project plans, laying out an appropriate scope of work and schedule to address the needs at each plant while also ensuring adequate resources for each phase. In preparing a work plan, the Company assessed the needs of the plants and current NFPA codes, the ongoing safety of Company employees and the public, prioritization of other capital work that was in progress, the extended operational lives of the plants to provide continuing service to customers, and any opportunity to refurbish existing equipment. All of these considerations contributed to the Company's plans to ensure the plants remain valuable resources on the system for the next 20 years or more. With the conclusion of the studies the projects were assigned to project managers to begin processing them through the Company's established project development and budgeting processes discussed earlier in my testimony. Details regarding the specific upgrade projects at each plant are provided in the individual plant sections below.

Q. WHAT IS THE COMPANY'S PLAN FOR COMPLETION OF THE FIRE DETECTION/SUPPRESSION UPGRADES NECESSARY AT THE PLANTS?

A. Given the extensive capital work at the plants that was in progress in 2021 and 2022, the Company planned a phased approach to implement the fire detection/suppression upgrade work beginning in 2023. The fire detection/suppression work at Wescott has begun, and design work is underway for Maplewood, with capital additions for the fire detection/suppression upgrades currently anticipated in 2024. Additional work at the Sibley plant is expected to begin in the fall of 2024, with in-service dates for the Sibley fire detection/suppression upgrades in 2025.

Q. PLEASE DISCUSS HOW THE COMPANY EVALUATED ALTERNATIVES TO REFURBISHING AND CONTINUING TO OPERATE THE GAS PEAKING PLANTS?

A. The Company considered alternatives to the overall refurbishment of the plants, as well as alternative upgrades to the existing fire water suppression systems at the plants. I discuss the individual plant options for Wescott and Maplewood in greater detail below. As previously noted, the primary purpose of these plants is to ensure adequate supply is available to serve customers' needs on the coldest days of the year. The only reasonable alternative to investing in the gas plants as a whole is to acquire an additional 246,000 Dth of firm upstream transportation capacity on NNG pipeline. However, NNG would need to construct substantial facilities over a three-year period to increase its pipeline capacity to serve this incremental load. In considering this alternative, the Company determined that it would have to pay approximately an additional, ongoing \$60 to \$70 million *per year* in pipeline demand charges for the new transportation service. Further, this alternative only provides transportation capacity; the Company would still be required to purchase the gas supply that the plants currently provide for coldest day needs.

Even with the phased approach to refurbishment of the gas plants from the initial investments to return to vaporization through completion of the fire detection/suppression systems, the Company's annual capital investment in the plants overall and with respect to refurbishment specifically is significantly lower than these amounts. Given the extended delay in service and the large costs involved, NNG construction is not a reasonable alternative. Additionally, the phased remediation major capital investments is rounded off by the fire detection/suppression projects. As such, the Company anticipates that future Plant capital projects will be managed considering plant trends, equipment reliability, identified safety requirements, and/or regulatory driven items, and will generally consist of smaller overall investments.

Q. HOW IS THE CURRENT FIRE DETECTION/SUPPRESSION UPGRADE WORK AT THE PLANTS BEING CARRIED OUT?

A. The Company has contracted with Campos to perform engineering, procurement, and construction for the Wescott fire detection/suppression projects based on previously agreed upon terms relative to their work on the earlier refurbishment projects. Campos has also been contracted to perform engineering services for the Maplewood and Sibley sites. We are in the process of determining the contractor for construction services at Maplewood and Sibley. The Company selected Campos EPC to complete the refurbishment work based on the following considerations, which are also applicable to the selection of Campos to perform the fire detection/suppression upgrade work:

- Campos has a proven track record with Xcel Energy and is a current Engineering Design Contractor having significant industry EPC pipeline work and plant experience.
- Campos EPC completed the engineering site analysis for Wescott, Sibley, and Maplewood during the plant investigations and reviews, so was already knowledgeable about the work to be completed at the peaking plants.
- Campos held a competitively bid Master Services Agreement for work at the plants.

- Campos has demonstrated expertise and experience with other similar gas plant facilities.
- Campos undertakes competitive bidding and selection for other resources necessary to complete the work at the plants.
- Campos has sufficient resources to complete the work in a timely fashion.

Q. HOW IS NSPM MANAGING THE FIRE DETECTION/SUPPRESSION UPGRADE WORK AT THE PLANTS TO ENSURE IT IS SUCCESSFUL AND COMPLETED AT REASONABLE COSTS?

A. At Wescott, Campos is managing the project under the EPC contract with Company oversight. As the projects are underway, they will be subject to multiple scope reviews to ensure constructability and that successful project completion has occurred and will continue to occur over the life of the project. The Company's project managers are actively engaged in any scope change and ensure that the process for approval of any change is being adhered to.

At Maplewood, the Company has procured Campos to perform the design engineering and is working through Supply Chain to identify and identify vendor procurement solutions to provide competitive pricing alternatives for vendors that will ultimately perform the construction. As with Wescott, once the projects are underway, they will be subject to multiple scope reviews to ensure constructability and that successful project completion has occurred and will continue to occur over the life of the project. The Company's project managers will also be actively engaged in any scope change.

(b) *Maplewood Fire Detection/Suppression Upgrades*

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I discuss the specific fire detection/suppression upgrades being undertaken at the Maplewood Plant.

Q. BEFORE PROVIDING DETAILS ABOUT THE MAPLEWOOD PROJECTS, CAN YOU DISCUSS THE CONCLUSIONS OF THE STUDY RELATED TO THE EXISTING FIRE DETECTION/SUPPRESSION SYSTEMS AT THE MAPLEWOOD PLANT?

A. The primary conclusion related to the Maplewood fire water capabilities was that upgrades to the fire water system would be needed due to the limitations of the single-source municipal water supply and the arrangement of the existing system. The Maplewood fire water hydraulic capabilities of the existing system were assessed with respect to the NFPA requirements specific to the number and configuration of the tanks at the plant. The Maplewood Existing Fire Water System Assessment is provided as Confidential Exhibit___(AEB-1), Schedule 7. Current industry standards recommend the total capacity of the fire water system to be at least the amount of fire water required to cool the largest container being protected, plus the amount required to cool adjacent containers, plus reserve capacity for three additional hand hose cooling streams. The study determined that due to the limitations of the water supply from the single municipal water source, the water pressure and volume that would be provided by fire department pumping apparatus expected to be utilized during an emergency incident, and the arrangement of the existing system, upgrades would be needed to ensure an adequate volume of water supply for the fire suppression system.

Regarding the fire detection system at the Maplewood plant, the assessments found that the modern Det-Tronics EQP safety systems providing the core fire, gas, and leak detection is in good working order and the local operating network reaches most of the areas of the plant. However, preliminary conclusions recommended upgrades to comply with more current codes, including expanding detection coverage and replacing outdated or missing equipment where needed. Initial recommendations also included evaluation, design, and installation of building fire alarm and detection systems and occupant notifications, and exterior notification systems, including audible notifications throughout the site as well as visual beacons indicating gas or fire for all buildings and enclosures. Initial recommendations also noted installation of new heat detection devices in the compressor building to comply with current codes and standards.

Q. CAN YOU DISCUSS INITIAL APPROACHES THE COMPANY CONSIDERED TO UPGRADE THE MAPLEWOOD FIRE WATER CAPABILITIES?

A. Yes. Due to the limitations of the single-source municipal water supply and the arrangement of the existing system, relying on the original, 1960s single-source water supply would not provide adequate water for the fire suppression system at the Maplewood plant based on the updated NFPA 59 requirements. As such, the Company initially contemplated connection to additional city water supplies, relocation of the pump house, the addition of a new water pump to comply with current NFPA code, and a new control center. With cost considerations in mind, this approach also contemplated use of existing infrastructure where possible.

Q. WHAT WERE SOME OF THE SPECIFIC ISSUES THE COMPANY IDENTIFIED RELATED TO UPGRADING THE EXISTING FIRE WATER SUPPRESSION SYSTEMS AT THE MAPLEWOOD PLANT?

A. First, the increased water volume resulting from the additional fire pump and new safety requirements would have overtaxed the existing infrastructure and supports such that all new foundations, structural steel, and supports for water distribution piping would have been required. In addition, the underground water header was reported to have significant leaks. The concern would be that these could not be addressed with a repair, but rather a replacement of the entire header due to the age of the piping.

Q. HOW DID THE COMPANY PROCEED WHEN THESE ISSUES WERE IDENTIFIED?

A. As evaluation of potential approaches continued, it became apparent that the requirements associated with bringing water from alternate city water sources and the associated below and above grade water suppression piping was drastically impacting the overall cost of the project. The Company then assessed implementation of a tank mounding system to comply with current NFPA fire suppression codes, rather than upgrading the fire water suppression systems for the tanks. Tank mounding reduces pressure management requirements necessary during high ambient temperatures in the summer months. The Company assessed an alternative mounding option used at another company's gas peaking plant, through informational meetings and a tour of their facility. The Company and Campos then developed comparable estimates for a mounding solution at the Maplewood plant. Campos consulted some of the same vendors that performed the mounding project reviewed and worked with the Campos construction division to draft estimates. Based on a comparison to cost estimate for upgrading the fire water suppression system, there was an overall cost savings associated with proceeding with the mounding project at the Maplewood plant. For these reasons, Company will implement a tank mounding system to comply with current NFPA fire suppression codes, rather than upgrading the existing fire water suppression system.

Q. PLEASE DESCRIBE THE TANK MOUNDING FIRE SUPPRESSION SYSTEM AT A HIGH LEVEL.

A. The purpose of fire suppression is to keep the tanks cool in the case of a fire at the plant site. Mounding the tanks is one method of achieving this by reducing the tanks exposure to external conditions. Instead of upgrading the fire water system onsite, burying – or "mounding" – the tanks will align with current NFPA 59 fire suppression code. This serves to reduce the amount of above grade fire water suppression and reduce overpressure concerns with above grade propane tanks and the impact of high ambient temperatures in the summer months.

Q. WHAT ARE THE COMPONENTS OF THE PLANNED FIRE DETECTION/ SUPPRESSION UPGRADE WORK AT THE MAPLEWOOD PLANT?

A. At the Maplewood plant, the Company will:

- Demolish existing structure components, fire water distribution systems tank bank piping and associated valves. Below grade piping will be abandoned in place.
- Replace and add fire detection equipment throughout the plant.
- Address additional water source requirements to support fire suppression systems outside of the mounding area.

- Utilize tank mounding approach to address fire suppression requirements in current NFPA code. Mounding includes removal and resurface protection on all the tank and new cathodic protection system to enhance life of the tanks, storm water drainage system in and around the mound, retaining wall systems to reduce potential cost impacts of expanding the site beyond the current layout due to potential infringement and reassessments of wetland areas.
- Install new tank bank piping, valves, controls and monitoring devices to the tanks supported and distributed on top of the mound.
- relocate and replace propane pumps due to mound system location and design requirements.

Q. WHAT WORK IS INVOLVED IN IMPLEMENTING THE TANK MOUNDING FIRE SUPPRESSION SYSTEM AT MAPLEWOOD?

A. Preparation of tanks for the mounding project will be completed for half of the tank farm at a time, with the first half to be prepared in the fourth quarter of 2023. First, propane inventory will be relocated to other tanks within the plant to maintain capacity requirements for the 2023-2024 heating season. The piping system and tanks will be emptied and purged of hydrocarbons, lifted off its concrete saddle, sand blasted, recoated, saddle replaced and placed back on supports. As the construction sequence will allow, demolition of the existing tank bank piping and valving will be removed in support of prior and subsequent activities. This sequence will be repeated for the second half of the tanks after the heating season when the plant is in holding mode (during late first/early second quarter 2024). All valves and piping for each tank will be removed and replaced. Propane pumps will be relocated outside of the mounding area due to design requirements. Sand will be brought in by truck as tanks are in place and associated valve, piping and fire suppression equipment is installed. The tank farm will be topped off with rock and walkways with stairs to provide access to the top of the tank farm. Manways will be installed on top of each tank for maintenance and isolation access. Propane inventory will then be replenished for the 2024-2025 heating season.

Q. PLEASE DESCRIBE THE CONCURRENT WORK ON THE NEW TANK BANK PROPANE DISTRIBUTION PIPING AND VALVES, INCLUDING CONTROLS AND MONITORING SYSTEMS.

A. Concurrent with the mounding project, all pipe valves and fittings in the tank bank area will be replaced. The current tank bank piping and associated valves are original to the plant along with all of the valves in the current system. Due to age and condition, replacement of the piping and valves was already planned to be completed from 2023 to 2025. However, as a result of proceeding with the mounding option, the future year tank bank piping and valve projects along with the propane pump replacement project were required to be performed as part of mounding the tanks. This is due to the design which relocates the existing components that are routed on described structural supports to being routed and supported on top of the mound. As part of this project all pipe valves and fittings in the tank bank area will be replaced. This work also includes installation of new control and monitoring systems, modernizing this equipment that will enhance plant reliability over the longer term.

Q. PLEASE EXPLAIN WHY THERE IS A NEED FOR RELOCATION OF THE PROPANE PUMPS AS PART OF THE MOUND SYSTEM REQUIREMENTS.

A. Propane pumps are located under the main header near the tank banks and are in direct conflict with the mounding footprint. Moving the pumps outside of the mounding area provides means of access for maintenance and monitoring performance. Similar to the earlier discussion pertaining to the tank bank piping and valves, the existing propane pumps were already included in the near future plans for replacement due to due to the age of existing pumps. Two new propane pumps will be installed as part of the mounding project.

Q. WITH THE TANK MOUNDING SYSTEM, IS THERE A CONTINUING NEED FOR SEPARATE FIRE WATER SUPPRESSION CAPABILITIES AT THE MAPLEWOOD PLANT?

A. Because the tank mounding system significantly reduces the need for fire water suppression capabilities at the plant site, extensive upgrades to the fire water infrastructure is not needed. That said, engineering analysis will determine any additional water requirements for other areas of the plant outside of the mounded tank bank area.

Q. PLEASE DESCRIBE THE UPGRADES TO THE FIRE AND GAS DETECTION EQUIPMENT AT THE MAPLEWOOD PLANT.

A. Fire and gas detection software and equipment at Maplewood is outdated and in varying states of operation. For example, the plants sometimes experience unjustified alarms driven by degraded underground conduit and cables that are a burden to operations. As such, the general site areas, vaporizer building, boiler building, compressor building, tank farms and truck unloading area will be replaced and upgraded with new components and above grade wiring. Upgraded monitoring systems will provide earlier detection and line of site to potential and/or occurring fire or overheating hazards. The types of equipment associated with all three plants are typical and include such items as fire eyes, gas detectors, fire detectors, horns, strobes, and other notification devices along with communications from these devices back to the control room where a new Det-Tronics display system will be in place for operations to observe and react as necessary.

Q. HOW DID THE COMPANY DEVELOP ITS BUDGET FOR THIS WORK AT THE MAPLEWOOD PLANT?

A. Budgets were based on preliminary engineering analyses and assessments. Cost estimates were developed by Company engineers, in conjunction with Campos, with support from contracted engineering firms and suppliers. These estimates were based on the costs of similar equipment and upgrades, and where possible, direct costs for engineering, materials, and construction were solicited directly from vendors. The Company, along with Campos also assessed the mounding option used at another company's gas peaking plant, as described above. Campos consulted some of the same vendors that performed that mounding project to inform project estimates for Maplewood. Additionally, the budget for the fire detection upgrades at the Maplewood plant were informed by project bids for the Wescott fire detection upgrades, which utilize the same equipment and related materials.

Budgets were developed based on the following cost categories: engineering and design; right-of-way acquisition and permitting; materials; construction; overheads; contingency; and the Company's costs related to overall project management and monitoring for such tasks as scheduling management and coordination, ongoing risk monitoring, and continuous variance reporting with respect to scope, schedule, and cost performance. Initial cost estimates for the overall project, on a capital expenditure basis, are provided in Confidential Exhibit___(AEB-1), Schedule 8. As the project is underway, it will be subject to multiple scope reviews to ensure that successful project completion has occurred and will continue to occur over the life of the project. The Company's project managers and Supply Chain function are actively engaged in any scope change and ensure that the process for approval of any change is being followed.

(c) *Wescott Fire Detection/Suppression Upgrades*

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I discuss the specific fire detection/suppression upgrades being undertaken at the Wescott Plant.

Q. BEFORE PROVIDING DETAILS ABOUT THE WESCOTT PROJECTS, WHAT WERE THE CONCLUSIONS OF THE STUDY RELATED TO THE EXISTING FIRE DETECTION/SUPPRESSION SYSTEMS AT THE WESCOTT PLANT?

A. The study of the Wescott fire water capabilities determined that upgrades to the system would be needed primarily based on issues related to the use of the single well as a water source by both the Wescott plant and the Flint Hills propane plant, and the inability to fully confirm the capacity of the well water to comply with current NFPA code requirements. The Wescott fire water hydraulic capabilities of the existing system were assessed with respect to the NFPA requirements for the production, storage, and handling of LNG, requiring the total capacity of the fire water system to be at least the amount of fire water needed for the largest potential maximum single incident, plus an allowance for hand hose streams, for not less than two hours. The Wescott Existing Fire Water System Assessment is provided as Confidential Exhibit___(AEB-1), Schedule 9. The study assessed the water supply to determine the hydraulic capabilities of the existing fire suppression systems at Wescott, which include water curtain, foam suppression, and fire sprinkler systems, and monitor nozzles. The study determined that upgrades would be needed to ensure an adequate volume of water supply for the fire suppression system under various emergency scenarios.

Regarding the fire detection system at the Wescott plant, the assessments found that the modern Det-Tronics EQP safety systems providing the core fire, gas, and leak detection are in good working order and the local operating network reaches most of the areas of the plants. Similar to the Maplewood plant, preliminary conclusions recommended upgrades to comply with more current codes, including expanding detection coverage and replacing outdated or missing equipment where needed. Initial recommendations also included evaluation, design, and installation of building fire alarm and detection systems and occupant notifications, and exterior notification systems, including audible notifications throughout the site as well as visual beacons indicating gas or fire for all buildings and enclosures.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE APPROACHES THE COMPANY CONSIDERED TO UPGRADE THESE SYSTEMS?

A. Yes. The primary conclusion of the assessment of the Wescott fire water capabilities that upgrades to the system would be needed due to the use of the single well as a water source for both the Wescott plant and the Flint Hills propane plant, and the inability to quantify the capacity of the well water to comply with current NFPA code requirements. Preliminary recommendations were to install a permanent connection to the municipal water supply to eliminate reliance on well water and replace the existing well pump with a new fire pump compliant with current NFPA code, supplied by the municipal water supply. Similar to the approach at the Maplewood plant, the Company initially contemplated upgrading the existing fire water suppression systems at the Wescott plant.

Q. WHAT WERE SOME OF THE CONSIDERATIONS AS THE COMPANY ASSESSED ALTERNATIVES AT THE WESCOTT PLANT?

A. Considerations included first the ability to segregate the water supply from the Flint Hills facilities. At a redesign of the current system to split the facilities. The second consideration was the ability to recertify the existing well on the Wescott property, determining if it could meet the two-hour water capacity NFPA 59A code requirement. That option, however, would not alleviate the combined water supply with Flint Hills; nor was recertification of the well possible due to the unquantifiable water supply. The Company also looked at single source water supply from a water tower. However, because this water tower is at the end of the city loop, the city of Eagan would not allow this as a single source for Wescott fire suppression, as the plant could use all the water in the event of an emergency over a defined period of time, putting the residential water supply at risk. Driven by the description earlier in this paragraph, the Company's ultimate plan includes connection to the city water supply at two locations, and the associated new equipment and infrastructure. I note that the tank mounding system being implemented at the Maplewood LPG facility is not an option for an LNG plant like Wescott. The Maplewood plant unloads propane from tanker trucks into 33 smaller bullet tanks in what is called a tank farm, compared to one ninety-foot-tall tank that holds approximately 24 million gallons of LNG at Wescott. There are also differences between governing requirements in NFPA 59 and NFPA 59A for each plant type.

Q. WHAT ARE THE COMPONENTS OF THE FIRE DETECTION/SUPPRESSION UPGRADE WORK AT THE WESCOTT PLANT?

A. At the Wescott plant, the Company will:

- Install two new water supply lines. One will use mechanical excavation from the water tower with a 12-inch water pipe. The other water line will be 8 inches from a separate water supply using directional boring methodologies and tie into the new 12-inch water line.
- The 12-inch water line will route to a new pump house that will house two independent fire pumps. This is a significant improvement against the previous design providing independence from the Flint Hills fire water system and redundancy for maintenance and unplanned pump downtime.
- Install a new fire pump building to house fire pumps.
- Install water distribution piping from the new pumps in the pump house to Flint Hills Refinery and Company tie in points to existing fire water distribution piping.
- Increase water piping size from main water distribution pipe to the boiler building to support boiler building fire suppression requirements.
- Install new power transformer and controls as required to operate the pumps and communicate fire monitoring status back to the control room operators.
- Site restoration of disturbed landscape and paving areas; and
- Upgrade fire and gas detection equipment.

Q. PLEASE DESCRIBE THE WORK INVOLVED IN INSTALLATION OF A NEW WATER MAIN SUPPLY LINE AND THE TWO CONNECTIONS TO THE CITY WATER SUPPLY.

A. This project will install a new water main supply line using both open trench and horizontal direction drilling (HDD) to connect water supply from the two municipal locations to the new fire pump building. In addition to the water tower connection on the south side of the property, the Company has been asked by the city of Eagan to install a second connection to ensure city water serving residents is not impacted in the case the designed maximum fire pump water output was needed for a duration greater than two hours. In addition, the city of Eagan has requested a water flow limiting component be added to the piping design as an additional measure to restrict water availability over the engineered design water demand requirements for the fire suppression system. Connections to city water supply will be made at the Southern Lakes water tower located adjacent to the Wescott plant, and near the plant entrance. This will consist of new 12-inch underground pipe from the water tower and an 8-inch pipe from the second connection point. The two water lines connect upstream of the pump house resulting in one line servicing the fire pumps. A 12-inch line will connect to the new pump house. Piping will comply with local burial depth requirements for freeze protection. Isolation valves will be strategically located to allow for maintenance and repairs, and required backflow prevention devices will be installed on the water side of the new fire pump to protect the municipal water supply.

Q. PLEASE DESCRIBE THE WORK INVOLVED IN INSTALLATION OF THE NEW FIRE PUMP AND BUILDING.

A. The new fire pump building houses the fire pump equipment. The location has been selected to reduce the amount of construction required for routing the new water main piping from the municipal water supply locations and existing station piping tie in points. Installing the new fire pump in a new location will also allow the existing well pump to remain in service throughout construction and continue to serve the potable water to the maintenance building. Construction will consist of installing a foundation and a prefabricated sheet metal building. In addition, the building will be protected by an automatic fire sprinkler system and equipped with a fire alarm system to comply with NFPA 59A and 101. The new fire pump arrangement will include the new water supply arrangement, pump, driver, control equipment, and power supply.

Q. WHAT WORK IS INVOLVED IN INSTALLING NEW POWER AND CONTROLS TO THE NEW FIRE PUMP BUILDING?

A. New power and control infrastructure will be installed at the new fire pump building that will provide the Wescott control room visibility to the pump house and associated components. A new transformer will be installed along with associated power cable to the pump house and control wiring from the pump house area to the control room.

Q. PLEASE DESCRIBE THE UPGRADES TO THE FIRE AND GAS DETECTION EQUIPMENT AT THE WESCOTT PLANT.

A. All existing fire eye and gas detection equipment and associated wiring located in the process area and plant buildings will be upgraded and replaced. New Det-Tronics panels that house all of the components will be upgraded and installed in the control room. A public address system will also be installed to provide audible instructions to plant workers if an abnormal operating condition (AOC) were to occur.

Q. WHAT IS THE CURRENT TIMELINE TO COMPLETION FOR THE SCOPE OF WORK RELATED TO THE FIRE DETECTION/SUPPRESSION UPGRADES AT THE WESCOTT PLANT?

A. Construction activity is expected to begin in January of 2024, and the project is expected to be in-serviced in late 2024.

Q. PLEASE PROVIDE ADDITIONAL INFORMATION REGARDING HOW THE COMPANY DEVELOPED ITS BUDGET FOR THE SCOPE OF THIS WORK AT WESCOTT?

A. Similar to the budgeting process discussed for the Maplewood project, the process for budget development of the work and related costs at the Wescott plant were developed by the Company engineers with support from contracted engineering firms and suppliers. These estimates were developed using parametric models based on the costs of similar equipment and upgrades performed by technical experts. Direct costs for engineering, materials, and construction were solicited directly from vendors specializing in this work. The budget included in the rate case forecast for the Wescott fire detection/suppression upgrades was largely bid out at the time of forecast. Budgets were developed based on the following cost categories: engineering and design; right-of-way acquisition and permitting; materials; construction; overheads; contingency; and the Company's costs related to overall project management and monitoring for such tasks as scheduling management and coordination, ongoing risk monitoring, and continuous variance reporting with respect to scope, schedule, and cost performance. Initial cost estimates for the overall project, on a capital expenditure basis, are provided in Confidential Schedule 8.

Q. HOW IS THE COMPANY MANAGING THE BUDGET FOR THESE PROJECTS TO STAY WITHIN BUDGET TO THE EXTENT POSSIBLE?

A. As mentioned earlier, as the project is underway, it will be subject to multiple scope reviews to ensure constructability and that successful project completion has occurred and will continue to occur over the life of the project. The Company's project managers are actively engaged in any scope change and ensure that the process for approval of any change is being adhered to. Additionally, the Campos EPC agreement institutes requirements for competitive bidding general contractor and subcontractors.

Q. PLEASE SUMMARIZE HOW THESE FIRE DETECTION AND SUPPRESSION PROJECTS WILL BENEFIT THE PLANTS AND NSPM CUSTOMERS OVERALL.

A. The fire protection and suppression projects are necessary to provide protection to public health and safety along with staff members on a daily basis. It also provides asset protection in the event of the fire, overheating and/or gas release event.

ii. Sibley Truck Unloading Station

Q. PLEASE DESCRIBE THE SIBLEY TRUCK UNLOADING STATION PROJECT.

A. The Sibley plant relies on liquid propane delivery by truck to maintain adequate inventory for vaporization during the heating season. This project will replace all below grade liquid propane piping with above grade piping and will replace all associated controls and electrical infrastructure for the two truck unloading stations at the plant. The budget for this project was originally developed in parallel with similar work that was completed at the Maplewood truck unloading station in 2022. The Company is evaluating construction resource alternatives such as using our own special construction team to perform this the Sibley truck unloading project versus utilization of Campos EPC. Replacing the truck unloading system will ensure safe and reliable operation of this critical process within the plant and placing it above grade will assist with future piping integrity assessments and preventative maintenance activities.

Q. DOES THIS PROJECT RELATE TO THE REFURBISHMENT OF THE PLANTS?

A. No. While the benefits of this work were identified as part of the overall assessment of the plants, these are unrelated capital investments to upgrade and modernize this original (1958) infrastructure. Bringing the infrastructure above grade allows for enhanced reliability and the ability to conduct maintenance more efficiently, helping ensure improved plant reliability and efficiency now and into the future.

iii. Maplewood Air Dryer

Q. PLEASE DESCRIBE THE MAPLEWOOD AIR DRYER PROJECT.

A. Propane air plants blend air and propane together to supplement natural gas supply within the distribution pipeline. The moisture content levels of this blend must not exceed the established threshold when leaving the facility. To meet that threshold, the compressed air must be run through an air dryer to remove any excess moisture prior to vaporizing. The Maplewood Air Dyer project consists of installing a new air dryer unit upstream of the vaporizer building, including associated mechanical piping and electrical and control infrastructure. The budget for this project was developed in conjunction with prior phased work for the vaporization project, based on the scope of work and costs under the Campos EPC contract. However, due to the long lead time of the air dryer, it was not able to be installed in prior years. Installation of this air dryer will ensure the gas leaving the plant is free of excess moisture that could affect the use of the gas on the system or the safe operation of appliances through which it flows.

Q. TO WHAT EXTENT DOES THIS PROJECT RELATE TO THE REFURBISHMENT OF THE PLANTS?

A. The plan for original vaporization projects initially included this air dryer, to be completed in conjunction with the vaporization projects. However, the lead time for the necessary equipment would have delayed resuming the vaporization process if the Company had waited for delivery of this equipment. Similar to the fire detection and suppression systems identified earlier, the Company's systematic testing determined that the plant's vaporization systems could be run safely without first completing this project. While the air dryer is not necessary for vaporization, it is important to monitor the gas quality output from the plant. The Company currently monitors the composition of the gas leaving the Maplewood plant via a gas chromatograph installed downstream from the plant to monitor the gas supply and would identify any issues. However, installation of the air dryer will ultimately help optimize gas quality which improves energy delivery to customers. The Company will install the air dryer in 2024 because the equipment has already been purchased; once it is put into service, the benefits of installing the air dryer will be realized.

c. Peaking Plant Routine Projects

Q. PLEASE PROVIDE AN OVERVIEW OF THE TYPES OF PROJECTS THAT CONSTITUTE ROUTINES AT THE PLANTS.

A. Plant routines are work typically totaling less than $300,000, budgeted to perform routine capital maintenance at the three peak shaving plants. Examples of routine capital plant maintenance include compressor overhauls, replacement of inoperable valves, and motor replacements. As with other Gas Operations routines, the budget for plant routines is based on a combination of historical spend and interviews with plant leadership to forecast for additional annual capital maintenance routine projects to ensure plant safety and reliability. Further, inputs and assumptions regarding inflation factors are used to determine the assumed cost increases or decreases. These inflation factors include but are not limited to labor, non-labor, contractor, materials, equipment and fleet inflation rates, and bargaining labor increases.

Q. PLEASE DESCRIBE THE PLANTS ROUTINE PLANT PROJECTS FOR 2024.

A. Table 10 below provides a breakdown by plant of the routine plant projects for 2024.

Table 10

Project Name	2024 Test Year
MN/Wescott Gas Production-LNG	$0.8
Sibley Gas Production/Manufacturing	$0.7
Maplewood Gas Production/Manufacturing	$0.2
Total	**$1.7**

Q. WHAT TYPES OF ROUTINE PROJECTS ARE INCLUDED IN THE 2024 TEST YEAR BUDGET?

A. At the Wescott LNG plant, routine projects in 2024 will focus on adding additional process monitoring instruments for both the liquefaction and vaporization phases including, adding flow meters for our liquefaction mixed refrigerant loop (MRL) skid, additional pressure, temperature, flow instrumentation on process piping to improve visibility in the control room, replacing four boiler control valves, and adding permanent platforms to elevated components to remove the need for temporary scaffolding in order to perform routine maintenance.

In 2024 planned routine work at the Sibley and Maplewood propane plant will focus on improving control room and building improvements and adding a storm shelter for plant personnel.

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL CAPITAL BUDGET FOR THE 2024 TEST YEAR.

A. NSPM's capital budgets for the 2024 test year are intended to provide for a reasonable level of capital investment that supports our NSPM gas infrastructure and our ability to provide safe and reliable service to our 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 can be broken down into 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 11 below summarizes the Company's base rate actual O&M expenses for 2020 through 2022, the 2023 forecast, and the budget for the 2024 test year. The O&M amounts by cost category are included in Exhibit___(AEB-

1), Schedule 10, and the O&M amounts by FERC account are included in Exhibit___(AEB-1), Schedule 11.

Table 11
Gas Operations O&M Budget by Category – 2020 through 2024
State of Minnesota Gas ($ millions)

O&M Categories	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
Damage Prevention	7.7	8.0	7.4	8.4	9.6
Labor	19.9	21.3	22.0	24.1	24.8
Outside Services	5.7	3.6	5.0	4.3	4.0
Materials	3.7	4.2	4.9	4.6	5.3
MGP	(0.8)	(1.1)	(0.3)	0.6	1.0
Transportation	2.4	2.6	3.7	3.4	3.6
Other	(3.5)	(3.3)	(3.1)	(4.8)	(6.3)
Total	**$35.1**	**$35.3**	**$39.6**	**$40.6**	**$42.0**

Q. WHAT ANNUAL GUIC RIDER O&M EXPENSES WERE INCURRED FROM 2020 AND FORECASTED THROUGH 2024?

A. Table 12 below summarizes the Company's expenses that have been recovered through the GUIC Rider from 2020 to 2022 and forecasted in 2023 and 2024.

Table 12
GUIC Rider O&M, 2020 through 2024
State of Minnesota Gas ($ millions)

State of MN	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
GUIC	1.8	1.4	0.3	0.8	1.9

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

A. Over the three years from 2020 to 2022, Gas Ops O&M costs increased, primarily related to labor cost increases, materials, and transportation. Increases in 2022 related to materials and transportation costs were largely due to supply chain issues and higher gas prices. During this same timeframe, our GUIC O&M costs decreased as certain projects were completed.

Q. WHAT IS THE COMPANY'S GAS OPERATIONS O&M BUDGET FOR THE 2024 TEST YEAR?

A. The Gas Operations base rate O&M budget for the 2024 test year is $42.0 million as described in Table 11 above. The basis for this budget is set forth in details below.

Q. AT A HIGH LEVEL, WHAT ARE THE MAJOR COST DRIVERS OF THE 2024 GAS OPERATIONS O&M BUDGET?

A. Of the categories listed above there are three primary drivers of our Gas Operations O&M budget: (1) Company Labor; (2) Damage Prevention; and (3) Materials. 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 2024 O&M INCREASES COMPARED TO PRIOR YEARS?

A. Yes. As shown in Table 11 above, the 2024 Gas Operations non-GUIC O&M budget has increased as compared to the 2022 actual O&M costs. These increases are driven by the three factors I noted above:

First, the Company's labor costs are increasing for the test year due mainly to bargaining unit contract increases. I describe the Company's test year labor costs in more detail later in my testimony.

Second, 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 an increasing number of locate requests, increasing costs associated with renewal of our outside service contract for Damage Prevention work, and increased bargaining unit wages for 2023 and 2024.

Third, the Company's costs for materials are increasing due mainly to inflation.

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 2022 actuals, GUIC Rider O&M costs are increasing primarily driven by an increase in work on our transmission pipeline assessment and programmatic replacement/MAOP remediation initiatives. Additional information regarding the GUIC Rider projects and costs can be found in our 2023 GUIC filing (Docket No. G002/M-22-578) and our 2024 GUIC petition that will be filed in October 2023.

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 Haworth 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 2024 test year, explaining the costs that are incurred and the drivers of cost changes from prior years in order to demonstrate that our 2024 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?

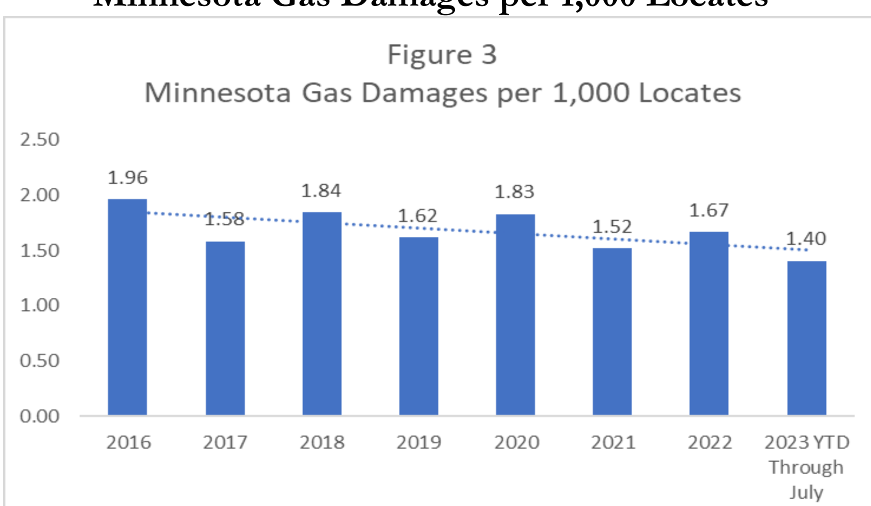
A. Yes. Whenever excavation and related construction occurs, damage to NSPM's underground facilities continues to be a significant risk to our gas distribution system. As a result, NSPM continues to institute a variety of outreach efforts to excavators regarding the importance of using Gopher State One 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, NSPM's damage prevention program fluctuates between first and second quartile performance as benchmarked with our industry peers. Figure 3 below illustrates the number of gas damages per 1,000 locates the Company has experienced since 2010. As indicated by Figure 3, as of 2022, the Company has seen a reduction of more than 27 percent in damages per 1,000 locates on our system since 2010.

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 phone 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 calls to the centralized phone 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. 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 calls to the Gopher State One Call line (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 is currently under contract with four vendors through January 31, 2026. Each of these vendors performs work in Minnesota. In 2020, when the Company's then-current contracts were about to expire, NSPM issued a request for proposal (RFP) to obtain damage prevention services. Vendors provided responses, resulting in three rounds of price negotiations. The Company implemented new contracts after the final RFP round, resulting in the contracts presently in effect.

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 2022, the Company performed more than 193,000 gas locates, and approximately 147,000 or 76 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 2020-2022?

A. Table 13 below shows the actual O&M costs associated with Damage Prevention in 2020, 2021, and 2022. Table 18 also contains forecasted Damage Prevention costs for 2023 and the 2024 test year.

Table 13
NSPM MN Gas Damage Prevention O&M Expenses ($ millions)

Damage Prevention O&M Cost Elements	2020 Actuals	2021 Actuals	2022 Actuals	2023 Forecast	2024 Test Year
Outside Services	6.8	7.0	6.5	7.4	8.7
Labor	0.7	0.7	0.7	0.8	0.8
Materials	0	0	0	0	0
Other	0.2	0.2	0.2	0.1	0.1
Total	**7.7**	**8.0**	**7.4**	**8.4**	**9.6**

Q. PLEASE EXPLAIN THE INCREASE FROM 2022 ACTUALS TO THE 2024 BUDGET FOR DAMAGE PREVENTION.

A. The $9.6 million Damage Prevention 2024 test year budget reflects a $2.2 million increase in Damage Prevention costs compared to 2022. This forecasted increase is attributable primarily to higher Outside Services cost, which reflect both higher costs for vendor services due to renegotiated vendor contracts, as well as an increase in the forecasted number of locate requests. Vendor costs increased due to inflationary pressures, and a tight labor market. Lastly, our workforce bargaining agreement negotiations were settled leading to an increase in wages for 2023 and 2024. Company witness Michael P. Deselich's Direct Testimony discusses the bargaining employee base wage increase.

Q. CAN YOU EXPLAIN THE FORECASTED INCREASE IN THE VOLUME OF TICKETS FROM 2023 TO 2024?

A. In 2024, we are forecasting a three percent increase in the number of locates compared to 2023. The increase in the volume of underground locate requests 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. HOW PREDICTABLE ARE DAMAGE PREVENTION COSTS?

A. The costs associated with Damage Prevention are volatile and outside the Company's control. The number of locate requests the Company receives are driven by the actions of customers and contractors, rather than NSPM. However, the Company's response to requests for Damage Prevention locates is mandated by law as discussed above.

Additionally, the costs are volatile, for a few reasons. First, the number and complexity of locates required in any given year is not within the Company's control, and can vary widely depending on the economy, the housing and commercial building or renovation markets, and amount of work performed by municipalities. Second, the periodic renegotiation of our vendor contracts and internal bargaining agreements which, at times results in step changes in cost. Third, we do not have many opportunities to moderate these costs given our statutory obligations and the limited means of providing these services.

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**: 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, Governance and Business Operations**: responsible for strategic direction of the overall gas organization, planning, and budgeting of short-term and long-term projects, provides risk management advocacy, interaction with state and federal agencies, and compliance with codes and standards;
- **Geospatial Asset Data**: accountable for advancing the integrity, quality, and function of business unit-related processes, asset data, and applications to meet/surpass industry standards; and

- **Gas Continuous Improvement**: streamlines functions from various areas of the Gas organization to ensure continued success and improvement in key business processes, systems, and support.

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 work force are bargaining unit 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 work force 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 2022, primarily due to an increase in wages. As previously mentioned in my testimony, the terms and conditions of our labor agreement were settled leading to a general wage increase of 6.1 percent in 2023 and 4 percent in 2024 applicable to our bargaining employees. To drive increased consistency in our operations and depth in the gas organization, headcount was added in 2021 and 2022, which accounts for some of the some of the increase in labor costs as those employees move through their apprenticeship and earn higher wages. Additional bargaining employees were added to help support critical gas infrastructure initiatives in Gas Plants and the IMMO project.

Q. WHY IS THE O&M LEVEL FOR LABOR REASONABLE FOR THE 2024 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 the need to add headcount to enhance oversight and serve our customers accordingly. 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 TEST YEAR?

A. Over time, our need for outside services work fluctuates as the needs of our system change. The 2024 budget is $4.0 million compared to $5.0 million actual costs for outside services incurred in 2022. 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 2024 budget is a reasonable, if not conservative, estimate of likely Gas Operations Outside Services work in 2024.

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 ARE MATERIALS COSTS INCREASING IN 2024?

A. The increase in 2024 is primarily due to inflationary pressures compared to 2022 actuals. The 2023 forecast as of July is slightly lower than 2022 actuals due to changes in the need for materials from year to year.

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 at the following four active MGP sites:

- **Fargo MGP Site:** Investigation of this site began in 2015 after MGP materials were encountered in City streets adjacent to the former MGP plant property in Fargo, North Dakota. Significant remedial work was completed at the site in 2018, followed by groundwater monitoring through 2020. Additional remedial work was performed in 2021 during street reconstruction activities adjacent to the site. We are currently negotiating an agreement for the sale of a portion of the site. Insurance recovery efforts were also completed in 2021. Insurance recoveries have offset the costs of the project, and any future sale proceeds will also be used to offset the costs of the project.

- **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, but whether further action will be needed at this site has not yet been determined. Insurance recovery efforts are complete for this site. Insurance recoveries have offset the costs of the project. In addition to the plant site, a related gas holder site is scheduled for demolition in 2023.

- **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 are in agreement. We are incurring some additional cost in 2023 for further evaluation of a gas holder that was connected to the Faribault plant site.

- **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 are in agreement.

Q. PLEASE IDENTIFY THE MGP O&M COST LEVEL THAT IS INCLUDED IN THE 2024 TEST YEAR.

A. We have included approximately $1.0 million for MGP cost in our 2024 test year. However, because the requirements of these sites vary substantially, this amount is based on historical amounts the Company has incurred on average, as offset by insurance recoveries, in prior years rather than certainty around 2024 costs. Note that the costs incurred are sometimes offset by insurance recoveries, but not always, and typically years after the spend was incurred. 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. We anticipate that the costs for these sites over a period of time will average out to approximately $1.0 million per year, 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. Additional details regarding these projects and costs were provided in Docket No. G002/M-17-894.

Q. HOW DOES THE 2024 MGP O&M COST LEVEL COMPARE WITH PREVIOUS YEARS?

A. As demonstrated in Table 11 above, MGP costs over the last few years vary significantly, with credits in 2020 through 2022 actuals. Further, we anticipate more work will be needed at existing and 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 $1.0 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 2020 through 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. Further, while the Company is required to clean up these sites, the Company does have some discretion as to the timing (at least in some instances). In years where the Company is under budgetary constraints, allowing deferral of these costs may allow 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 2024.

A. The Transportation O&M costs to be incurred in 2024 total approximately $3.6 million, which is slightly lower than actual costs incurred in 2022. The increase in Transportation costs since 2020 is due primarily to increase in fuel costs beginning in 2022. Company witness Bhosale 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 and 2024 primarily related to first set meter credits. Supply chain challenges delayed many of our meter deliveries in recent years. Manufacturers are still catching up on trailing orders. As a result, meters received in 2023 and 2024 are forecasted to be higher than recent years.

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 docket,[3] I provide information on spending related to the Company's COVID-19 Relief & Recovery projects. I also address a compliance item stemming from our 2022 Gas Rate Case, requiring the Company to submit a compliance filing in January 2024 related to capital asset accounting and property records. Finally, although not specific requirements in this case, I address certain requirements related to GUIC O&M costs as well as a question about Damage Prevention cost allocations that was raised in the Company's 2009 gas rate case.

Q. DOES GAS OPERATIONS' BUDGET FOR 2023 AND 2024 INCLUDE ANY ACCELERATED WORK ASSOCIATED WITH THE COVID-19 RELIEF & RECOVERY DOCKET?[4]

A. Yes. Table 14 below outlines the small dollar amounts related to reliability projects that will be accelerated and in-serviced in 2023 and 2024. This portfolio of accelerated gas infrastructure projects will provide system benefits by improving system reliability and public safety. These infrastructure projects include replacing copper risers and services and installing additional isolation valves. Consistent with the Commission's March 12, 2021 Order,[5] the Company has been tracking its spending related to these COVID-19 Relief & Recovery

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[3] *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).
[4] *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).
[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).

projects, and the Company has been providing this information to the Commission as part of its quarterly compliance filings in that docket.[6]

Table 14
Gas Operations Reliability COVID-19 Relief & Recovery
Capital Additions ($ millions)

Project Name	Project Description	2023 Forecast	2024 Test Year
Replacement of Copper Risers and Services	Replacing copper risers and services improves public safety by completing needed aged infrastructure replacements.	$0.2	$0.0
Distribution Isolation Valves	Isolation valves can be used to cut the flow of gas in the event of a pipeline emergency, which ensures public safety and speeds up required repair work.	$0.2	$0.0
Total		**$0.4**	**$0.0**

Q. HOW DO CUSTOMERS BENEFIT FROM THE ACCELERATION OF THESE PROJECTS?

A. The intent of the COVID-19 Relief & Recovery docket was to investigate investments utilities could make that would assist in Minnesota's economic recovery from the COVID-19 Pandemic. These projects are appropriate for acceleration because they improve both system reliability and public safety while creating jobs. These jobs will also include criteria to consider businesses owned by women, veterans, or minorities.

[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 2023, SECOND QUARTER REPORT COVID-19 RELIEF & RECOVERY, (July 31, 2023).

Q. WHAT ACCOUNTING AND PROPERTY RECORDS INFORMATION IS THE COMPANY REQUIRED TO PROVIDE STEMMING FROM THE COMPANY'S 2022 GAS RATE CASE?

A. The Settlement Agreement in the Company's 2009 Gas Rate Case required the following:

> For purposes of this Settlement, the Settling Parties agree that within nine months of the Commission's final order in this proceeding, the Company will provide a compliance filing explaining (1) the steps it has taken or will take to eliminate or reduce discrepancies between its capital asset accounting records and its operational records for gas pipeline safety infrastructure and impediments to eliminating or reducing discrepancies; (2) the relationship between property records and the removal of physical assets from the system, explaining where it is possible to identify whether an asset has been removed before or after the end of the depreciable life; and (3) where methods of accounting versus operational record-keeping for gas pipeline infrastructure result in reasonable differences between the data in the types of records. [7]

Q. WHEN IS THIS COMPLIANCE FILING DUE?

A. This compliance filing is due within nine months of the Commission's final Order in the 2022 Gas Rate Case. As such, the Company will submit its compliance filing on capital asset accounting and property records on or before January 13, 2024, in Docket No. G002/GR-21-678.

Q. WHAT RELEVANT COMMISSION ORDER POINT FOR THIS RATE CASE AROSE FROM THE COMMISSION'S JANUARY 27, 2015, ORDER APPROVING RIDER WITH MODIFICATIONS IN DOCKET NO. G002/M-14-336?

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[7] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy's Petition for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G002/GR-21-678, COMPREHENSIVE AND UNANIMOUS SETTLEMENT AGREEMENT at Section III.E (October 4, 2022), and ORDER ACCEPTING AGREEMENT AND SETTING RATES AND UPDATING BASE COST OF GAS at p. 7 (April 13, 2023).

A. In Order Point 4 from the referenced Order, the Commission required that:

> In the initial filing in its next natural-gas rate case, Xcel shall submit detailed schedules, any necessary supporting documentation, and an explanation of all O&M costs that were being recovered in the rider and are now included in the test year for recovery in base rates.[8]

Q. IS THE COMPANY SUBMITTING DETAILED SCHEDULES AND SUPPORTING DOCUMENTATION ADDRESSING THESE COSTS IN THIS RATE CASE?

A. Yes. The Company complied with this requirement in its next rate case, the 2022 Gas Rate case, as required. Although not specifically a requirement in this case, Company witness Halama provides this detail in his Direct Testimony. The Company understands it always has an obligation to provide information on rider recoveries in its rate cases. This will continue to be addressed in the Company's Revenue Requirements testimony, but the requirement from Docket No. G002/M-14-336 noted above will not be addressed in Gas Operations testimony in future rate cases.

Q. WHAT QUESTIONS WERE RAISED WITH RESPECT TO DAMAGE PREVENTION COST ALLOCATION IN THE COMPANY'S 2009 GAS RATE CASE?

A. In the Company's 2009 gas rate case in Docket No. G009/GR-09-1153, the Minnesota Office of Attorney General – Residential and Small Business Utilities Division (OAG) raised questions about NSPM's tracking of total locating and marking tickets, particularly with respect to tracking the actual number of tickets by customer type (electric, gas, or combined) to ensure appropriate allocation of Damage Prevention expenses. The Company committed to investigate the

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[8] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Rider,* Docket No. G002/M-14-336, ORDER APPROVING RIDER WITH MODIFICATIONS at p. 14 (January 27, 2015)

matter further and report on its actions and recommendations in its next natural gas rate case.

Q. HAS NSPM SINCE CHANGED THE WAY IT TRACKS LOCATE TICKETS AND ASSIGNS COSTS TO THE RESPONSIBLE OPERATING DIVISION?

A. Yes. As discussed in Direct Testimony in the 2022 Gas Rate Case, the Company is now able to track locates based on the type of service involved and assigns costs accordingly. As a result, the Damage Prevention costs described above appropriately reflect our NSPM gas costs. Because the Company reported on this issue in detail in its 2022 Gas Rate Case, and no intervenors in that case addressed this topic, the Company will no longer provide an update on this issue in future rate cases.

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, including our peaking plants, 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 2024 and beyond.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

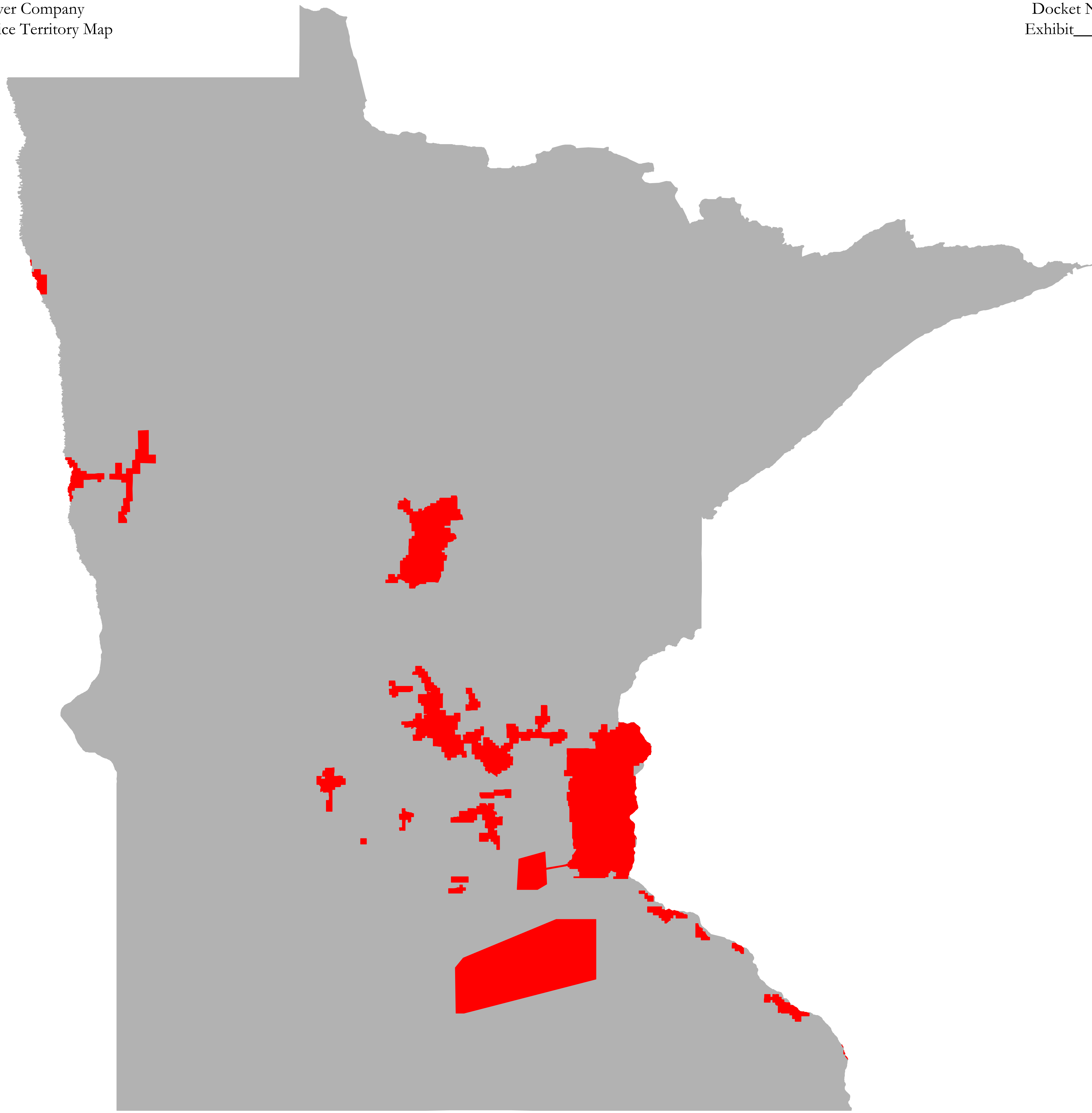
Alicia E. Berger

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. My duties are directing 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.

Northern States Power Company
Minnesota Gas Service Territory Map



										($ Millions)				
										Actual Additions			Forecasted Additions	
Line #	MN Gas Witness	Major category	Function Class Description	Project ID	Project Nbr Desc	Expenditure Type	Project Type	Rate Review Category	Major Project	2020	2021	2022	2023	2024
1	Berger	New Business	Gas Distribution Plant	A.0006062.002	Distribution CIAC MN Gas	New Const CIAC-Gas	Routine	New Business-Other		$61,007	$109,875	$251,937	$246,256	$165,000
2	Berger	New Business	Gas Distribution Plant	A.0006062.017	Gas Clring Wo_s- Credits for CRS	New Const CIAC-Gas	Discrete	New Business-Other					$116,676	
3	Berger	New Business	Gas Distribution Plant	D.0005014.012	Minnesota-Gas Meter Blanket	Purch Gas Meters	Routine	New Business	New Meter	($11,440,307)	($9,306,730)	($11,976,832)	($16,436,133)	($11,134,000)
4	Berger	New Business	Gas Distribution Plant	E.0000004.003	MNGD New Mains-MN	New Mains	Routine	New Business	New Mains Routine	$1,927			($69,972)	($288)
5	Berger	New Business	Gas Distribution Plant	E.0000004.012	Northwest-New Gas Mains	New Mains	Routine	New Business	New Mains Routine	$632	($346)			
6	Berger	New Business	Gas Distribution Plant	E.0000004.015	Newport-Gas New Mains	New Mains	Routine	New Business	New Mains Routine		$291			
7	Berger	New Business	Gas Distribution Plant	E.0000004.016	Southeast- New Gas Mains	New Mains	Routine	New Business	New Mains Routine		($59)			
8	Berger	New Business	Gas Distribution Plant	E.0000004.068	NW	New Mains	Discrete	New Business	New Mains Routine	$129				
9	Berger	New Business	Gas Distribution Plant	E.0000004.071	BRD/Pillager Gas Install	New Services	Discrete	New Business-Other		$33,787				
10	Berger	New Business	Gas Distribution Plant	E.0000004.084	MN - Service Retro Fit AG Prot	New Services	Routine	New Business-Other		($81,508)	($44,978)	($75,330)	($16,118)	
11	Berger	New Business	Gas Distribution Plant	E.0000004.086	NSM Gas Service Conversion Pro	New Services	Routine	New Business-Other		($5,034)				
12	Berger	New Business	Gas Distribution Plant	E.0000005.002	MNGD New Services-MN	New Services	Routine	New Business	New Services Routine	($9,113)				
13	Berger	New Business	Gas Distribution Plant	E.0000005.023	Newport-Gas New Services	New Services	Routine	New Business	New Services Routine		($104)			
14	Berger	New Business	Gas Distribution Plant	E.0000005.037	NW	New Services	Discrete	New Business	New Services Routine	$3,638				
15	Berger	New Business	Gas Distribution Plant	E.0000005.038	BRD	New Services	Discrete	New Business	New Services Routine	$2				
16	Berger	New Business	Gas Distribution Plant	E.0000009.006	Newport-Reg/Meter Station Inst	Install Non-Trans Reg/Mtr Stat	Routine	New Business-Other		($61,318)	($11,754)	$105	$23,972	
17	Berger	New Business	Gas Distribution Plant	E.0000009.022	St Paul-Syst Reg & Mtr Station Inst	Install Non-Trans Reg/Mtr Stat	Routine	New Business-Other		($89,115)	($49,062)			
18	Berger	New Business	Gas Distribution Plant	E.0000009.025	Northwest-Reg/Meter Sta Instal	Install Non-Trans Reg/Mtr Stat	Routine	New Business-Other		($69)				
19	Berger	New Business	Gas Distribution Plant	E.0000009.027	Southeast-Sys Reg & Mtr Inst	Install Non-Trans Reg/Mtr Stat	Routine	New Business-Other		($16,225)	($11,266)	$16	($10,527)	$44
20	Berger	New Business	Gas Distribution Plant	E.0000009.040	White Bear-Sys Reg & Mtr Station In	Install Non-Trans Reg/Mtr Stat	Routine	New Business-Other					($9,152)	
21	Berger	New Business	Gas Distribution Plant	E.0000009.048	Northwest-Sys Reg & Mtr Station Ins	Install Non-Trans Reg/Mtr Stat	Routine	New Business-Other		$17,875			($34,171)	
22	Berger	New Business	Gas Distribution Plant	E.0000009.099	NW/Gas/Barnesville Regulator S	Install Non-Trans Reg/Mtr Stat	Discrete	New Business-Other		$1,041				
23	Berger	New Business	Gas Distribution Plant	E.0010001.001	MN - Gas New Mains Blanket	New Mains	Routine	New Business	New Mains Routine	($5,250,539)	($7,030,557)	($8,570,169)	($6,416,337)	($8,449,300)
24	Berger	New Business	Gas Distribution Plant	E.0010001.002	MN - Gas New Services Blanket	New Services	Routine	New Business	New Services Routine	($7,654,330)	($8,930,993)	($10,596,163)	($8,957,109)	($11,087,799)
25	Berger	New Business	Gas Distribution Plant	E.0010001.003	MN - Gas New Business WCF	WCF-Gas New Service	Routine	New Business-Other					$0	($1,394,000)
26	Berger	New Business	Gas Distribution Plant	E.0010033.005	MN/STP/District Energy Reinforce	New Mains	Discrete	New Business-Other					($399)	
27	Berger	New Business	Gas Distribution Plant	E.0010033.007	MN/NW/Sartell/Sartell High School	New Mains	Discrete	New Business-Other		($2,733)				
28	Berger	New Business	Gas Distribution Plant	E.0010033.014	MN/NPT/MEH/R406 Retirement	New Mains	Discrete	New Business-Other		($117,662)				
29	Berger	New Business	Gas Distribution Plant	E.0010033.021	NPT/MPW/M024/ Main Install	New Mains	Discrete	New Business-Other			($116,319)			
30	Berger	New Business	Gas Distribution Plant	E.0010033.026	MN/STP/STP/Highland Bridge Backbone	New Mains	Discrete	New Business-Other			($489,549)	$1,561		
31	Berger	New Business	Gas Distribution Plant	E.0010075.035	MN/NPT/MPW/ M024 Retirement	Rebuild Non-Trans Reg/Mtr Stat	Discrete	New Business-Other					($61)	
32	Berger	New Business	Gas Distribution Plant	E.0010033.029	MN/NW/New Main/Sherco Electrical Pl	New Mains	Discrete	New Business-Other				($5,068,471)	($45,400)	
33	Berger	New Business	Gas Distribution Plant	E.0010033.030	MN/NW/Reinforcement/Delano New Busi	New Services	Discrete	New Business-Other			($417,876)	($23,215)		
34	Berger	New Business	Gas Distribution Plant	E.0010033.033	MN/NPT/Cottage Grove Logistics Park	New Mains	Discrete	New Business-Other				($276,103)	$11,745	
35	Berger	New Business	Gas Distribution Plant	E.0010033.034	MN/NSPM/TL0209/ECL/MAOP&Casing Proj	Main Relocation	Discrete	New Business-Other					($175,471)	
36	Berger	New Business	Gas Transmission Plant	E.0000018.007	NSM Trans Line Install	Gas Trans New Main	Discrete	New Business-Other			($18,971)			
37	Berger	New Business	Gas Transmission Plant	E.0000018.008	Black Dog Pipeline	Gas Trans New Main	Discrete	New Business-Other		($65)				
38	Berger	New Business	Gas Transmission Plant	E.0010073.008	MN/Pine Bend RNG Interconnect Pipe	Gas Trans New Main	Discrete	New Business-Other				($14,046)		
39	Berger	New Business	Gas Transmission Plant	E.0010075.030	MN/Pine Bend RNG Interconnect/Reg	Install Gas Trans Reg/Mtr Stat	Discrete	New Business-Other				($274,357)	$257,242	
40	Berger	Reliability	Gas Distribution Plant	E.0000002.003	MNGD Service RenwlCutoff-MN	Service RenwlCutoff	Routine	Reliability	Service Renewal/Cuttoff Routine		($85)			
41	Berger	Reliability	Gas Distribution Plant	E.0000007.002	MNGD Main Renewal-MN	Main Renewal	Routine	Reliability	Main Renewal Routine	($677)				
42	Berger	Reliability	Gas Distribution Plant	E.0000007.007	Newport-Gas Main Renewal	Main Renewal	Routine	Reliability	Main Renewal Routine	($227)				
43	Berger	Reliability	Gas Distribution Plant	E.0000007.008	Replace Main Under Hwy 10	Main Renewal	Discrete	Reliability - Other		($1,111,598)				
44	Berger	Reliability	Gas Distribution Plant	E.0000008.002	MNGM Main Reinforcement-MN	Main Reinforcement	Routine	Reliability	Main Reinforcement Routine	$2				
45	Berger	Reliability	Gas Distribution Plant	E.0000008.007	NW\Howard Lake Reinforcemnt	Main Reinforcement	Routine	Reliability - Other				($333,504)		
46	Berger	Reliability	Gas Distribution Plant	E.0000008.033	MN/WYO/Frst Lk/Reinforce S060 PH 1	Main Reinforcement	Discrete	Reliability - Other		$3				
47	Berger	Reliability	Gas Distribution Plant	E.0000009.091	Replace obsolete regulators -	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($367,798)	($1,859)		($66,051)	
48	Berger	Reliability	Gas Distribution Plant	E.0000012.025	MN-Placeholder Discrete Proj with n	Not in WorkBook	Routine	Reliability - Other					($23,782)	($214,564)
49	Berger	Reliability	Gas Distribution Plant	E.0010001.004	MN/Meter Module Meter Exchange	Purch Gas Meters	Discrete	Reliability	Meter Module Replacement				($5,326,686)	($5,329,000)
50	Berger	Reliability	Gas Distribution Plant	E.0010011.001	MN - Gas Main Renewal Blanket	Main Renewal	Routine	Reliability	Main Renewal Routine	($1,463,661)	($655,556)	($1,094,669)	($1,178,868)	($985,746)
51	Berger	Reliability	Gas Distribution Plant	E.0010011.002	MN - Gas Service Renewal Blanket	Service RenwlCutoff	Routine	Reliability	Service Renewal/Cuttoff Routine	($2,454,089)	($2,361,488)	($2,626,474)	($2,173,538)	($2,754,842)
52	Berger	Reliability	Gas Distribution Plant	E.0010011.007	MN - Quarantine Pipe Replacement 20	Main Renewal	Routine	Reliability - Other				$36,492		
53	Berger	Reliability	Gas Distribution Plant	E.0010011.013	MN/R&R/Distribution Isolation Valve	Main Renewal	Discrete	Reliability - Other			($142,766)		($193,242)	
54	Berger	Reliability	Gas Distribution Plant	E.0010011.014	MN/R&R/Copper Service Renewal	Service RenwlCutoff	Discrete	Reliability - Other			($1,184,844)	($15,430)	$3,647	
55	Berger	Reliability	Gas Distribution Plant	E.0010011.016	MN Gas Cathodic Protection Blanket	Not in WorkBook	Routine	Reliability - Other			($58,242)	($212,350)	($580,540)	($389,000)
56	Berger	Reliability	Gas Distribution Plant	E.0010016.001	MN - Gas Main Reinforcements Blanke	Main Reinforcement	Routine	Reliability	Main Reinforcement Routine	($131,188)	($2,535,907)	($2,449,745)	($1,984,039)	($2,796,888)
57	Berger	Reliability	Gas Distribution Plant	E.0010033.004	NSPM - Newport- HWY 149 Renewal - 1	New Mains	Discrete	Reliability - Other		($791)			$1,360	
58	Berger	Reliability	Gas Distribution Plant	E.0010033.009	MN\STC\2019 Jefferson Blvd Reinf	Main Reinforcement	Discrete	Reliability - Other		($594,775)	$6,755			
59	Berger	Reliability	Gas Distribution Plant	E.0010033.016	MN/St Cloud/Sartell Sys Cap HP Pipe	Non-Trans New Main	Discrete	Reliability - Other				($4,495,474)		
60	Berger	Reliability	Gas Distribution Plant	E.0010033.018	MN/Becker / Big Lake Entitlement	Non-Trans New Main	Discrete	Reliability - Other			($1,343,552)	($1,736,025)	($96)	
61	Berger	Reliability	Gas Distribution Plant	E.0010033.019	MN/NW/Saukview Dr Reinforcement Pro	New Mains	Discrete	Reliability - Other			($9,813)			
62	Berger	Reliability	Gas Distribution Plant	E.0010033.020	MN/Delano Convert Install TBS Mains	New Mains	Discrete	Reliability - Other			($91,437)			
63	Berger	Reliability	Gas Distribution Plant	E.0010033.023	MN/NW/Inglewood Dr Phase 2 Reinforc	New Mains	Discrete	Reliability - Other				($697,443)	$53,346	
64	Berger	Reliability	Gas Distribution Plant	E.0010033.024	MN/NPT/CTG/M030 System Replacement	Main Reinforcement	Discrete	Reliability - Other				($27,391)	($37,167)	($447,734)
65	Berger	Reliability	Gas Distribution Plant	E.0010033.025	MN/NW/Kandiyohi Farmtap	New Mains	Discrete	Reliability - Other			($403,146)	($201)	$3,074	
66	Berger	Reliability	Gas Distribution Plant	E.0010043.001	STP/STP/Lafayette Bridge Xing	Main Renewal	Discrete	Reliability - Other		($3,130,039)	($2,570,990)	($25,554)		
67	Berger	Reliability	Gas Distribution Plant	E.0010043.002	MN/STP/Forest St Bridge Xing	Main Renewal	Discrete	Reliability						($1,785,398)
68	Berger	Reliability	Gas Distribution Plant	E.0010043.005	MN/WBL/LT CANADA/Rice St Bridge X	Main Renewal	Discrete	Reliability - Other		($1,000,706)	$21,135			
69	Berger	Reliability	Gas Distribution Plant	E.0010043.008	MN/STC/Royalton 6"Poly Reinforceme	New Mains	Discrete	Reliability - Other		($685,520)			$59,680	
70	Berger	Reliability	Gas Distribution Plant	E.0010043.020	MN/STP/FLH/M007 System Replacement	Main Renewal	Discrete	Reliability - Other			($373,488)	($414,234)		
71	Berger	Reliability	Gas Distribution Plant	E.0010043.021	MN/STP/M001 System Replacement	Main Renewal	Discrete	Reliability - Other					($118,493)	
72	Berger	Reliability	Gas Distribution Plant	E.0010048.002	MN/WBL/HGO/Forest Blvd S008 system	Main Reinforcement	Discrete	Reliability - Other		($54,004)			$105,652	
73	Berger	Reliability	Gas Distribution Plant	E.0010048.003	MN/WYO/HML/Bunker Lake Blvd 8" main	Main Reinforcement	Discrete	Reliability - Other		$26,347	($4,274)		$208,930	
74	Berger	Reliability	Gas Distribution Plant	E.0010048.006	MN/NW/Becker/Hwy 10 - Industrial BL	Main Reinforcement	Discrete	Reliability - Other			($369,147)			
75	Berger	Reliability	Gas Distribution Plant	E.0010048.007	MN/NW/Baxter -Inglewood Dr, Baxter	Main Reinforcement	Discrete	Reliability - Other		($602,916)				
76	Berger	Reliability	Gas Distribution Plant	E.0010048.008	MN/SE/St.Clair/607th Ave TBS Odoriz	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($248,179)				
77	Berger	Reliability	Gas Distribution Plant	E.0010048.009	MN/SE/ML/490th St TBS Odorizer Repl	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($161,299)				
78	Berger	Reliability	Gas Distribution Plant	E.0010048.012	MN/WBL/NB/285th Ave-15000 of 4 PE m	Main Reinforcement	Discrete	Reliability - Other		($694,472)	($510)			
79	Berger	Reliability	Gas Distribution Plant	E.0010048.013	MN/St Cloud/Sartell Sys Cap HP Reg	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other			($117,801)	($33,304)		
80	Berger	Reliability	Gas Distribution Plant	E.0010048.014	MN/St Cloud/Sartell Sys Cap Pipe	Main Reinforcement	Discrete	Reliability - Other			($2,873,600)	($233,730)		
81	Berger	Reliability	Gas Distribution Plant	E.0010048.015	MN/STP/RSV/R037 Reg Rebuild - Main	Main Reinforcement	Discrete	Reliability - Other					($27,182)	
82	Berger	Reliability	Gas Distribution Plant	E.0010048.016	MN/STP/STP/R178 Main Reinf.	Main Reinforcement	Discrete	Reliability - Other					($32,455)	
83	Berger	Reliability	Gas Distribution Plant	E.0010048.017	MN/NPT/CTG/M030 System Replacement	Main Reinforcement	Discrete	Reliability - Other			($29,190)			
84	Berger	Reliability	Gas Distribution Plant	E.0010075.002	MN/STP/Plato and Water Regulator Re	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($423,698)				
85	Berger	Reliability	Gas Distribution Plant	E.0010075.003	MN/STP/Filter Separatr Instl on R10	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other			$371			
86	Berger	Reliability	Gas Distribution Plant	E.0010075.004	Moorhead Underpass-Reg Station	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($59,166)				
87	Berger	Reliability	Gas Distribution Plant	E.0010075.008	MN/Mendota Heights/R359 Controller	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($34,312)				
88	Berger	Reliability	Gas Distribution Plant	E.0010075.022	MN/NPT/MEH/R406 Retirement	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other			($340)			
89	Berger	Reliability	Gas Distribution Plant	E.0010075.023	MN/Mendota Heights/Mendota Station	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other			($41,732)			
90	Berger	Reliability	Gas Distribution Plant	E.0010075.025	MN/STP/ STP/ R172 Reg Station Rebui	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($101,867)			$13	
91	Berger	Reliability	Gas Distribution Plant	E.0010075.026	MN\BRD\Filter Separator Installatio	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($89,201)	

										Actual Additions			Forecasted Additions	
Line #	MN Gas Witness	Major category	Function Class Description	Project ID	Project Nbr Desc	Expenditure Type	Project Type	Rate Review Category	Major Project	2020	2021	2022	2023	2024
92	Berger	Reliability	Gas Distribution Plant	E.0010075.027	MN/Filter Separator Installation Pr	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other				($85,722)		
93	Berger	Reliability	Gas Distribution Plant	E.0010075.028	MN/Delano/Convert/ Install TBS-Reg	Other-Gas	Discrete	Reliability - Other					($632,193)	
94	Berger	Reliability	Gas Distribution Plant	E.0010075.029	MN/NW/Delano & Watertown MAOP Split	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other			($752,378)		$12,913	
95	Berger	Reliability	Gas Distribution Plant	E.0010075.032	MN/STP/ RSV/ R059 Reg Station Rebui	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other				($319,585)	$7,253	
96	Berger	Reliability	Gas Distribution Plant	E.0010075.033	MN/Delano Convert Inst TBS-Reg Stat	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other				($8,386,578)	($2,272,494)	
97	Berger	Reliability	Gas Distribution Plant	E.0010075.036	MN/NPT/WSP/R361 Reg Station Rebuild	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability						($387,358)
98	Berger	Reliability	Gas Distribution Plant	E.0010075.037	MN/STP/RSV/R037 Reg Rebuild	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other						($225,795)
99	Berger	Reliability	Gas Distribution Plant	E.0010075.041	MN/NPT/CTG/M030 System Reg	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other						($188,719)
100	Berger	Reliability	Gas Distribution Plant	E.0010075.042	MN/STP/STP/R178 Reg Rebuild	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other						($187,780)
101	Berger	Reliability	Gas Distribution Plant	E.0010011.018	MN - Gas Service Cutoff Blanket	Service RenwlCutoff	Routine	Reliability	Service Renewal/Cuttoff Routine				($5,615)	
102	Berger	Reliability	Gas Distribution Plant	E.0010038.048	MN/Redwing -Service Controls Upgrad	Other-Gas	Discrete	Reliability - Other					($7,992)	
103	Berger	Reliability	Gas Distribution Plant	E.0010043.025	MN/NW/New Main/Shakopee/Marystown R	Main Renewal	Discrete	Reliability - Other			($268,999)	($17,343)	($7,097)	
104	Berger	Reliability	Gas Distribution Plant	E.0010048.020	MN/NW/Reinforcement/STC/Ridgewood L	Main Reinforcement	Discrete	Reliability - Other			($333,447)	($4,050)	$33,476	
105	Berger	Reliability	Gas Distribution Plant	E.0010048.022	MN/NW/Reinforcement/STC/35th St NE	Main Reinforcement	Discrete	Reliability - Other			($314,095)	($133,960)		
106	Berger	Reliability	Gas Distribution Plant	E.0010075.012	MN/STP/RSV/Rice & Co Rd C Reg Rebld	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other			($73,755)			
107	Berger	Reliability	Gas Distribution Plant	E.0010075.039	MN/EGF/Gas/Replace Original Odorize	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other			($176,353)		$1,782	
108	Berger	Reliability	Gas Distribution Plant	E.0010075.049	NSPM Reg Stations - Pilot Heater In	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($94,847)	
109	Berger	Reliability	Gas Distribution Plant	E.0010011.020	NSM-MN-GasDist-Mixed-OQ	Not in WorkBook	Routine	Reliability - Other				($244,973)	($274,281)	
110	Berger	Reliability	Gas Distribution Plant	E.0010011.021	NSM-MN-GasDist-Mixed-OQ-GER	Not in WorkBook	Routine	Reliability - Other				($46,611)	($6,784)	
111	Berger	Reliability	Gas Distribution Plant	E.0010043.022	MN/NPT/STP/M002 System Replacement	Main Renewal	Discrete	Reliability - Other					($408,417)	
112	Berger	Reliability	Gas Distribution Plant	E.0010043.028	MN/NSPM-St Cloud/ Renew 8 inch Dist	Main Renewal	Discrete	Reliability - Other					($516,765)	$0
113	Berger	Reliability	Gas Distribution Plant	E.0010048.025	MN/STC/Darrow Ave SE Delano 6"PE R	Main Reinforcement	Discrete	Reliability - Other					($155,538)	$0
114	Berger	Reliability	Gas Distribution Plant	E.0010048.027	MN/NW/STC/SAUK RAPIDS/MGSL RNFC	Main Reinforcement	Discrete	Reliability - Other				($85,624)	($5,868)	
115	Berger	Reliability	Gas Distribution Plant	E.0010048.028	MN/NW/RNFC/STC/ST AUGUSTA/CNTY 75	Main Reinforcement	Discrete	Reliability - Other				($1,066,451)	$89,057	
116	Berger	Reliability	Gas Distribution Plant	E.0010048.031	MN/NPT/2022 Reinforcement/Robert S	Main Reinforcement	Discrete	Reliability - Other					$21,832	
117	Berger	Reliability	Gas Distribution Plant	E.0010048.032	MN/WBL/Buffalo St Reinforcement	New Mains	Discrete	Reliability - Other				($342,738)	$42,209	
118	Berger	Reliability	Gas Distribution Plant	E.0010048.033	MN/NPT/2022 Reinforcement/Woodbury	Main Reinforcement	Discrete	Reliability - Other				($649,325)	($19,487)	
119	Berger	Reliability	Gas Distribution Plant	E.0010048.034	MN/NPT/2022 Reinforcement/Woodbury	Main Reinforcement	Discrete	Reliability - Other				($839,122)	($1,188,842)	
120	Berger	Reliability	Gas Distribution Plant	E.0010048.035	MN/GRT/Dellwood Rd N/5400ft 4in rei	Main Reinforcement	Discrete	Reliability - Other				($269,862)	$20,487	
121	Berger	Reliability	Gas Distribution Plant	E.0010048.036	MN/WBL/Lake Ave/3300ft 6in reinforc	Main Reinforcement	Discrete	Reliability - Other				($291,955)	($64,060)	
122	Berger	Reliability	Gas Distribution Plant	E.0010048.037	MN/NW/BRD/Whitefish/FatherFoleyDr 4	New Mains	Discrete	Reliability - Other				($212,838)	($184,435)	
123	Berger	Reliability	Gas Distribution Plant	E.0010075.038	MN/STP/STP/R378 Reg Rebuild	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($11,308)	
124	Berger	Reliability	Gas Distribution Plant	E.0010075.047	MN/NW/Reinforcemnt/STC/35thStNE Reg	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other				($621,075)	($52,997)	
125	Berger	Reliability	Gas Distribution Plant	E.0010075.048	NW/Reinforcement/STC/Sauk Rapid Reg	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($55,395)	
126	Berger	Reliability	Gas Distribution Plant	E.0010075.053	MN/NW/REL/WSTC/MN BLVD	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($98,580)	
127	Berger	Reliability	Gas Distribution Plant	E.0010075.054	MN/STC/2022 RegStn Upgrades	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($33,417)	
128	Berger	Reliability	Gas Distribution Plant	E.0010075.060	MN/WBL/SHV/R398 Block Valve Replace	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($2,371)	
129	Berger	Reliability	Gas Distribution Plant	E.0010075.063	MN/STP/R537 Pilot Heater Replacemen	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($8,983)	
130	Berger	Reliability	Gas Distribution Plant	E.0000089.001	MN/RDW/Grandview Mobile Hm Comm/Rne	Main Renewal	Discrete	Reliability - Other					($44,758)	
131	Berger	Reliability	Gas Distribution Plant	E.0000092.001	MN/SHV/Victoria St N\6in reinfcmt	Main Reinforcement	Discrete	Reliability - Other					($450,256)	
132	Berger	Reliability	Gas Distribution Plant	E.0000115.001	MN/RENF/STP/Josephine Rd M008 Reinf	Main Reinforcement	Discrete	Reliability - Other					($522,286)	
133	Berger	Reliability	Gas Distribution Plant	E.0000126.001	MN/GAS/ R4396 Move AboveGrade	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($196,363)	
134	Berger	Reliability	Gas Distribution Plant	E.0010033.031	MN/Saint Michael IP Reinforcement	Non-Trans New Main	Discrete	Reliability						($1,515,553)
135	Berger	Reliability	Gas Distribution Plant	E.0010043.032	MN/STY\Sunrise Dr\4700ft 2in replac	Main Renewal	Discrete	Reliability - Other					($340,555)	
136	Berger	Reliability	Gas Distribution Plant	E.0010043.033	MN/STCL/2023 Recon/Division Street	Main Renewal	Discrete	Reliability - Other					($239,983)	
137	Berger	Reliability	Gas Distribution Plant	E.0010048.030	MN/R4349 HP Pipeline Reinforcement	Non-Trans New Main	Discrete	Reliability - Other						$0
138	Berger	Reliability	Gas Distribution Plant	E.0010048.038	MN/WBL/Krech Ave/4900ft 2in reinfor	Main Reinforcement	Discrete	Reliability - Other					($169,667)	
139	Berger	Reliability	Gas Distribution Plant	E.0010073.015	MN/Faribault/TBS#1 Rebuild_HP Line	Gas Trans New Main	Discrete	Reliability	Faiabult TBS Project					($652,052)
140	Berger	Reliability	Gas Distribution Plant	E.0010075.005	MN/Sauk Rapids\ 2nd Ave S AG Reg	Install Non-Trans Reg/Mtr Stat	Discrete	Reliability						($603,901)
141	Berger	Reliability	Gas Distribution Plant	E.0010075.040	MN/NPT/MEH/R365 Building Rebuild	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($325,014)	
142	Berger	Reliability	Gas Distribution Plant	E.0010075.045	MN/Mendota Heights/Mendota Station	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($140,406)	
143	Berger	Reliability	Gas Distribution Plant	E.0010075.058	MN/North St Paul/Henry and County B	Not in WorkBook	Discrete	Reliability - Other					($4,898)	
144	Berger	Reliability	Gas Distribution Plant	E.0010075.061	MN/New Brighton/H005 Old HWY 8 Relo	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($521,548)	
145	Berger	Reliability	Gas Distribution Plant	E.0010075.062	MN\STP/R410 Pilot Heater Replacemen	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($39,629)	
146	Berger	Reliability	Gas Distribution Plant	E.0010075.066	MN/MPW/ R304 Reg Station Rebuild	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($58,415)	
147	Berger	Reliability	Gas Distribution Plant	E.0010075.069	MN/RW/R4673 Replacement Due To Corr	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($34,211)	
148	Berger	Reliability	Gas Distribution Plant	E.0010076.008	ND/Gas/Fargo-TBS odorizer	Other-Gas	Discrete	Reliability - Other					($90,883)	
149	Berger	Reliability	Gas General Plant	A.0006059.149	MN Install Gas Communication E	Gas Comm Equip	Routine	Reliability - Other			($8,518)			
150	Berger	Reliability	Gas General Plant	A.0006059.461	MN Install Gas Communication E	Gas Comm Equip	Routine	Reliability - Other					$1,870	
151	Berger	Reliability	Gas General Plant	A.0006059.516	NSPM-Gas OT Cyber Security	Gas Tools And Equip	Discrete	Reliability - Other					($10,033)	
152	Berger	Reliability	Gas General Plant	E.0000024.014	NSPM Comm Equip - Dist Meter/R	Gas Comm Equip	Routine	Reliability - Other		($17,596)	($2,382)	($17,128)	($14,131)	
153	Berger	Reliability	Gas General Plant	E.0000024.017	NSPM Comm Equip - Trans Meter/	Gas Comm Equip	Routine	Reliability - Other		($76)		($115)		
154	Berger	Reliability	Gas General Plant	E.0010023.001	MN - Gas Communication Equip. Blank	Gas Comm Equip	Routine	Reliability - Other					($6,434)	
155	Berger	Reliability	Gas General Plant	E.0010023.002	MN/Meter Module Replacement	Gas Comm Equip	Discrete	Reliability	Meter Module Replacement				($14,424,725)	($14,424,707)
156	Berger	Reliability	Gas General Plant	E.0010024.002	ND/Meter Module Replacement	Gas Comm Equip	Discrete	Reliability	Meter Module Replacement				($2,364,181)	($1,861,623)
157	Berger	Reliability	Gas General Plant	E.0010053.001	MN/CP/ GAS Rectifier Compliance Rea	Gas Comm Equip	Discrete	Reliability - Other					($381)	
158	Berger	Reliability	Gas General Plant	E.0010053.006	NSPM/GDIST/PRESSURE MONITOR ERXs MN	Gas Comm Equip	Discrete	Reliability - Other		($188,510)	($119,014)	($22,456)	($283,717)	($90,209)
159	Berger	Reliability	Gas General Plant	E.0010053.007	NSPM/GDIST/PRESSURE MONITOR ERXs Ma	Gas Comm Equip	Discrete	Reliability - Other		($27,763)	($11,968)		($10,368)	
160	Berger	Reliability	Gas General Plant	E.0010054.002	NSPM/GDIST/PRESSURE MONITOR ERXs ND	Gas Comm Equip	Discrete	Reliability - Other		($67,099)		($6,528)		
161	Berger	Reliability	Gas General Plant	E.0000042.005	MN/WBL/County Rd B Replacement-NSP	Gas Comm Equip	Discrete	Reliability - Other				($9,425)		
162	Berger	Reliability	Gas General Plant	E.0010053.014	MN/Inver Hills/Lateral RTU Replace	Gas Comm Equip	Discrete	Reliability - Other				($14,472)		
163	Berger	Reliability	Gas General Plant	E.0010054.003	NSPM/GDIST/PRESSURE MONITOR ERXs ND	Gas Comm Equip	Discrete	Reliability - Other				($6,800)		
164	Berger	Reliability	Gas General Plant	E.0010053.015	MN/Scada Build Out	Gas Comm Equip	Discrete	Reliability					($686,636)	($724,935)
165	Berger	Reliability	Gas Intangible Plant	D.0001855.001	MN/Gas GPS Data Model Project	Not in WorkBook	Discrete	Reliability - Other						($37,604)
166	Berger	Reliability	Gas Transmission Plant	E.0000009.015	MN/Replace obsolete regulators	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other		($114)				
167	Berger	Reliability	Gas Transmission Plant	E.0000009.072	Mendota/Sendout Instrumentation Upg	Gas Processing Equipment	Discrete	Reliability - Other		($22,208)	($2,215)			
168	Berger	Reliability	Gas Transmission Plant	E.0010073.005	MN/NPT/IGH/CP/BLACKBERRY TRL RECTIF	Gas Trans Renewal	Discrete	Reliability - Other		($74,872)				
169	Berger	Reliability	Gas Transmission Plant	E.0010073.009	MN/NW/MN/NW/Granite City Retirement	Gas Trans Renewal	Discrete	Reliability - Other					($7,523)	
170	Berger	Reliability	Gas Transmission Plant	E.0010073.010	NSPM/IGH/Rich Valley Sta/ R506 Inle	Gas Trans Reinforce	Discrete	Reliability - Other				($117,315)	$12,687	
171	Berger	Reliability	Gas Transmission Plant	E.0010075.019	MN/EGF/Gas/Replace Original Odorize	Rebuild Gas Trans Reg/Mtr Stat	Discrete	Reliability - Other			$0			
172	Berger	Reliability	Gas Transmission Plant	E.0010075.021	MN/MHD/Replace Line Heater at MHD T	Upgrade Gas Trans Reg/Mtr Stat	Discrete	Reliability - Other			($759,168)		$2,889	
173	Berger	Reliability	Gas Transmission Plant	E.0010075.044	MN/NW/R1008 Reinforcement Project	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability						($358,484)
174	Berger	Reliability	Gas Transmission Plant	E.0010076.011	MN/EGF/Replace Line Heater at EGF T	Upgrade Gas Trans Reg/Mtr Stat	Discrete	Reliability - Other			($152,559)			
175	Berger	Reliability	Gas Transmission Plant	E.0000041.026	MN/Wescott/Odorizer rebuild and rep	Other-Gas	Discrete	Reliability - Other					($498,660)	
176	Berger	Reliability	Gas Transmission Plant	E.0010075.056	MN/SCL/East St Cloud Odorizer Proje	Upgrade Non-Trans Reg/Mtr Stat	Discrete	Reliability - Other					($210,882)	
177	Berger	Reliability	Gas Transmission Plant	E.0000088.001	MN/Lake Elmo 1B/Relocate TBS	Install Gas Trans Reg/Mtr Stat	Discrete	Reliability						($749,452)
178	Berger	Reliability	Gas Transmission Plant	E.0010043.031	MN/TYF/Taylors Falls/TBS Odorizer	Rebuild Gas Trans Reg/Mtr Stat	Discrete	Reliability - Other					($999)	
179	Berger	Reliability	Gas Transmission Plant	E.0010073.017	MN/WSTN/BLUE LAKE/CP MITIGATION	Other-Gas	Discrete	Reliability - Other					($30,860)	
180	Berger	Reliability	Gas Transmission Plant	E.0010075.055	MN/Faribault/TBS#1 Rebuild_ Odorize	Upgrade Gas Trans Reg/Mtr Stat	Discrete	Reliability	Faiabult TBS Project					($270,784)
181	Berger	Reliability	Gas Transmission Plant	E.0010075.068	MNGas/Moorhead-TBS odorizer	Other-Gas	Discrete	Reliability - Other					($212,712)	
182	Berger	Safety	Common General Plant	A.0006059.072	Gas Leak Training Center	Gas Tools And Equip	Discrete	Safety-Other		($1)				
183	Berger	Safety	Gas Distribution Plant	E.0000006.039	Capitalized Locating Costs-Gas	Facility Locates-Gas	Discrete	Safety	Capitalized Locating Costs - Gas	($790,884)	($827,768)	$536	($161)	($0)

										Actual Additions			Forecasted Additions	
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184	Berger	Safety	Gas Distribution Plant	E.0010011.008	MN/Inside Meter Move-out Purchase	Purch Gas Meters	Discrete	Safety	Inside Meter Move-out				($649,962)	($745,000)
185	Berger	Safety	Gas Distribution Plant	E.0010011.009	MN/Inside Meter Move-out Svc Renewa	Service RenwlCutoff	Discrete	Safety	Inside Meter Move-out			($50,248)	($1,086,572)	($2,825,000)
186	Berger	Safety	Gas Distribution Plant	E.0010011.019	NSM-MN-Gas-Locates	Facility Locates-Gas	Discrete	Safety	Capitalized Locating Costs - Gas			($505,093)	($646,848)	($787,000)
187	Berger	Safety	Gas General Plant	A.0005014.082	NSPM Gas Dist General Office E	Other-Gas	Discrete	Safety-Other			$1			
188	Berger	Safety	Gas General Plant	A.0006059.009	MN-Dist Gas Tools and Equip	Gas Tools And Equip	Discrete	Safety-Other		($371,913)	($1,372,470)	($694,103)	($530,252)	($769,565)
189	Berger	Safety	Gas General Plant	A.0006059.010	ND-Dist Dist Tools and Equip	Gas Tools And Equip	Discrete	Safety-Other		($94,090)	($64,252)	($47,317)	($70,649)	($71,567)
190	Berger	Safety	Gas General Plant	A.0006059.523	MN-Gas Tools & Equip	Gas Tools And Equip	Discrete	Safety-Other				($544,110)	($999,684)	($424,984)
191	Berger	Plants	Gas General Plant	E.0010080.006	MN/Maplewood/Outdoor Lighting Upgra	Other-Gas	Routine	Plants			$7			
192	Berger	Plants	Gas General Plant	E.0010080.008	MN/Wescott/Door and Window Replacem	Other-Gas	Routine	Plants			($24)			
193	Berger	Plants	Gas General Plant	E.0010080.010	MN/Wescott/LNG Boil-off compressors	Gas Storage Facilities	Routine	Plants			$3,114		($742)	
194	Berger	Plants	Gas General Plant	E.0000068.004	MN/Wescott/PA System	Gas Comm Equip	Routine	Plants					($1,036)	
195	Berger	Plants	Gas General Plant	E.0000068.006	MN/Wescott/Instrument Air Communica	Gas Storage Facilities	Routine	Plants						($301,117)
196	Berger	Plants	Gas Intangible Plant	A.0006059.546	MN/Wescott/Integrity Verification M	Gas Tools And Equip	Routine	Plants				($1,278,807)	($72,619)	
197	Berger	Plants	Gas Intangible Plant	A.0006059.547	MN/Sibley/Integrity Verification	Gas Tools And Equip	Routine	Plants				($463,389)	($42,924)	
198	Berger	Plants	Gas Intangible Plant	A.0006059.548	MN/Maplewood/Integrity Verification	Gas Tools And Equip	Routine	Plants				($511,308)	($29,716)	
199	Berger	Plants	Gas Manufactured Production Plant	E.0000021.006	Maplewood Gas Production/Manuf	Gas Processing Equipment	Discrete	Plants			($51,981)		($156,734)	($223,688)
200	Berger	Plants	Gas Manufactured Production Plant	E.0000021.008	Sibley Gas Production/Manufacturing	Gas Processing Equipment	Discrete	Plants		($16,783)	($714,228)	($138,643)	($165,873)	($654,809)
201	Berger	Plants	Gas Manufactured Production Plant	E.0000041.005	MN/6" Wescott to Sibley Propane Lin	Gas Processing Equipment	Discrete	Plants		$2,611				
202	Berger	Plants	Gas Manufactured Production Plant	E.0000041.006	MN/Sibley Truck Loading	Gas Storage Facilities	Discrete	Plants		($105,881)				
203	Berger	Plants	Gas Manufactured Production Plant	E.0010080.015	MN/Sibley Valve Replacement	Gas Storage Facilities	Routine	Plants			($1,601,937)	($16,793)		
204	Berger	Plants	Gas Manufactured Production Plant	E.0010080.017	MN/Maplewood Truck Unloading Statio	Gas Storage Facilities	Routine	Plants				($4,823,027)	($373,866)	
205	Berger	Plants	Gas Manufactured Production Plant	E.0010080.031	MN/Propane Plant/Sibley/vaporizatio	Not in WorkBook	Discrete	Plants				($16,062,997)	($579,927)	
206	Berger	Plants	Gas Manufactured Production Plant	E.0010080.032	MN/Propane Plant/Maplewood/vaporiza	Gas Storage Facilities	Discrete	Plants				($15,184,013)	($561,869)	
207	Berger	Plants	Gas Manufactured Production Plant	E.0010080.026	MN/Maplewood/Leaking Valve Replacem	Gas Storage Facilities	Discrete	Plants					($226,340)	
208	Berger	Plants	Gas Manufactured Production Plant	E.0010083.005	MN/MAPLEWOOD/Tank Bank Catwalk and	Other-Gas	Discrete	Plants				($5)	($825)	
209	Berger	Plants	Gas Manufactured Production Plant	E.0010083.006	MN/MAPLEWOOD/MWBMS1 - Boiler Manage	Other-Gas	Discrete	Plants				($372,831)	($24,000)	
210	Berger	Plants	Gas Manufactured Production Plant	E.0010083.007	MN/SIBLEY/SLTKU1 - Truck Unloading	Other-Gas	Discrete	Plants	Sibley Truck Loading					($2,885,457)
211	Berger	Plants	Gas Manufactured Production Plant	E.0010083.008	MN/SIBLEY/Catwalk and Stairs for Ta	Other-Gas	Discrete	Plants				$8		
212	Berger	Plants	Gas Manufactured Production Plant	E.0010083.009	MN/SIBLEY/Tank Bank Electrical and	Other-Gas	Discrete	Plants					($61,739)	
213	Berger	Plants	Gas Manufactured Production Plant	E.0010083.010	MN/SIBLEY/SLBMS1 - Boiler Managemen	Other-Gas	Discrete	Plants				($358,887)	($1,733)	
214	Berger	Plants	Gas Manufactured Production Plant	E.0010083.011	MN/MAPLEWOOD/MWFWP1-MWFRD1	Other-Gas	Discrete	Plants	Maplewood Fire Detection/Suppression Upgrades					($26,689,406)
215	Berger	Plants	Gas Manufactured Production Plant	E.0010083.013	MN/MAPLEWOOD/MWPAC 1&2 - Add Air Co	Other-Gas	Discrete	Plants					($2,718,034)	
216	Berger	Plants	Gas Manufactured Production Plant	E.0010083.026	MN/SIBLEY/Tank Bank Upgrade 1 & 2	Other-Gas	Discrete	Plants						$10,062
217	Berger	Plants	Gas Manufactured Production Plant	E.0010083.028	MN/MW/Tanks Banks 3,4,6 Piping Upgr	Other-Gas	Discrete	Plants						$0
218	Berger	Plants	Gas Manufactured Production Plant	E.0000086.001	MN/MPW/MAPLEWOOD/AIR DRYER	Rebuild Non-Trans Reg/Mtr Stat	Discrete	Plants	Maplewood Air Dryer					($1,536,510)
219	Berger	Plants	Gas Manufactured Production Plant	E.0010083.029	MN/MEH/INST/SIBLEY/PAD Gas Compres	Gas Storage Facilities	Discrete	Plants					($57,280)	
220	Berger	Plants	Gas Manufactured Production Plant	E.0010083.030	MN/MPW/SEMR/INST/PAD Gas Compresr	Gas Storage Facilities	Discrete	Plants					($131,991)	
221	Berger	Plants	Gas Manufactured Production Plant	E.0010083.031	MN/Oil-Water Separator for C301	Gas Processing Equipment	Discrete	Plants					($26,055)	
222	Berger	Plants	Gas Other Storage Plant	E.0000016.001	Gas Plants & Holders-Smal	Gas Storage Facilities	Discrete	Plants		($68,077)	($240,814)		($19,816)	($6,792)
223	Berger	Plants	Gas Other Storage Plant	E.0000021.004	Wescott Gas Production/Manufac	Gas Processing Equipment	Discrete	Plants		($216,770)	($20,076)	$0	($6,719)	
224	Berger	Plants	Gas Other Storage Plant	E.0000041.003	MN/Wescott LPG Plant Prod	Gas Processing Equipment	Discrete	Plants		($21,723)	($4)		($87,510)	
225	Berger	Plants	Gas Other Storage Plant	E.0000041.009	MN/Wescott LNG Plant Project Securi	Other-Gas	Discrete	Plants		($365,563)				
226	Berger	Plants	Gas Other Storage Plant	E.0010080.013	MN/Wescott LNG/Cold Box Replacement	Gas Storage Facilities	Discrete	Plants		($3,076,860)	($432,038)	($625,237)	($276,276)	
227	Berger	Plants	Gas Other Storage Plant	E.0010080.014	MN/Wescott Gas Production-LNG	Gas Processing Equipment	Discrete	Plants			($48,941)	($5,602,411)	($1,028,249)	($803,312)
228	Berger	Plants	Gas Other Storage Plant	E.0010080.016	MN/Wescott C201 Compressor Overhaul	Gas Storage Facilities	Discrete	Plants			($314,714)			
229	Berger	Plants	Gas Other Storage Plant	E.0010080.018	MN/Wescott/E108-E109 HE Replacement	Gas Storage Facilities	Discrete	Plants				($225)	($1)	
230	Berger	Plants	Gas Other Storage Plant	E.0010080.019	MN/Inver Grove Heights/Wescott Flow	Gas Storage Facilities	Discrete	Plants				($813,412)		
231	Berger	Plants	Gas Other Storage Plant	E.0010080.020	MN/Wescott/C101 compressor overhaul	Gas Storage Facilities	Discrete	Plants					($1,221,942)	
232	Berger	Plants	Gas Other Storage Plant	E.0010080.022	MN/Wescott/Adsorber Sieve Changeout	Gas Storage Facilities	Discrete	Plants				($3,549,114)	($62,393)	
233	Berger	Plants	Gas Other Storage Plant	E.0010080.024	MN/Wescott/GT101/C101 compressor co	Gas Storage Facilities	Discrete	Plants					($1,642,662)	
234	Berger	Plants	Gas Other Storage Plant	E.0010080.025	MN/Wescott/Install VFD on motors	Gas Storage Facilities	Discrete	Plants			($778,403)	($116,400)	($6,766)	
235	Berger	Plants	Gas Other Storage Plant	E.0010080.035	MN/Wescott/Upgrade Fire Protection	Other-Gas	Discrete	Plants	Wescott Fire Detection/Suppression Upgrades					($12,582,069)
236	Berger	Plants	Gas Other Storage Plant	E.0010080.036	MN/Wescott/Thermal Relief Upgrades	Gas Storage Facilities	Discrete	Plants			($5,803,417)	($926,017)	($135)	
237	Berger	Plants	Gas Other Storage Plant	E.0010080.039	MN/Wescott C105 New Compressor inst	Gas Storage Facilities	Discrete	Plants					($18,726)	
238	Berger	Plants	Gas Other Storage Plant	E.0000041.015	MN/Wescott/T-1 Purge and Decommissio	Other-Gas	Discrete	Plants					($1,616)	
239	Berger	Plants	Gas Other Storage Plant	E.0010080.040	MN/Wescott - Pipe Integrity Verific	Gas Storage Facilities	Discrete	Plants					($793,879)	
240	Berger	Plants	Gas Other Storage Plant	E.0010080.045	MN/WESCOTT/WLCPSV - Add liquefactio	Other-Gas	Discrete	Plants				($973,845)	($30,149)	
241	Berger	Plants	Gas Other Storage Plant	E.0010080.046	MN/Wescott/Tank 2- Outlet valve req	Gas Storage Facilities	Discrete	Plants				($1,316,417)	($216,746)	
242	Berger	Plants	Gas Other Storage Plant	E.0010080.047	MN/Wescott/WV1031 - Replace V103A T	Other-Gas	Discrete	Plants				($170,754)	($4,154)	
243	Berger	Plants	Gas Other Storage Plant	E.0010080.048	MN/Wescott/Add Liquefaction & Boil	Not in WorkBook	Discrete	Plants				($125,342)	($26,965)	
244	Berger	Plants	Gas Other Storage Plant	E.0010080.049	MN/Wescott/Dual Strainers MRL C101	Gas Storage Facilities	Discrete	Plants					($1,736)	
245	Berger	Plants	Gas Other Storage Plant	E.0000041.017	MN/WESCOTT/Inlet Meter Building Com	Other-Gas	Discrete	Plants					($3,407,441)	
246	Berger	Plants	Gas Other Storage Plant	E.0000041.018	MN/Wescott/Boiler Building Louvres	Other-Gas	Discrete	Plants						($424,786)
247	Berger	Plants	Gas Other Storage Plant	E.0000068.001	MN/Wescott/MRL Instrumentation Upgr	Gas Storage Facilities	Discrete	Plants					($319,509)	
248	Berger	Plants	Gas Other Storage Plant	E.0000068.002	MN/Wescott/C-201 Motor Upgrade	Other-Gas	Discrete	Plants					($111,961)	
249	Berger	Plants	Gas Other Storage Plant	E.0000068.003	MN/Wescott/C-201/C301 PLC Upgrades	Other-Gas	Discrete	Plants					($606,762)	
250	Berger	Plants	Gas Other Storage Plant	E.0000068.005	MN/Wescott/GT-101 Gas Emission Cont	Gas Storage Facilities	Discrete	Plants						($83,006)
251	Berger	Plants	Gas Other Storage Plant	E.0000068.008	MN/Wescott/C102/C103 Redundant Cont	Gas Storage Facilities	Discrete	Plants						($209,617)
252	Berger	Plants	Gas Other Storage Plant	E.0000068.009	MN/Wescott/MRL Instrumentation Cont	Gas Storage Facilities	Discrete	Plants						($250,703)
253	Berger	Plants	Gas Other Storage Plant	E.0000068.010	MN/Wescott/WEG Skid Replacement	Gas Storage Facilities	Discrete	Plants						($604,105)
254	Berger	Plants	Gas Other Storage Plant	E.0000068.011	MN/Wescott/Exchanger Platforms	Gas Storage Facilities	Discrete	Plants						($827,884)
255	Berger	Plants	Gas Other Storage Plant	E.0000068.013	MN/Wescott/Increase Subyard Transfo	Gas Storage Facilities	Discrete	Plants						($0)
256	Berger	Plants	Gas Other Storage Plant	E.0000068.014	MN/Wescott/Permanent Ethylene Tank	Gas Storage Facilities	Discrete	Plants						($463,506)
257	Berger	Plants	Gas Other Storage Plant	E.0000068.016	MN/Wescott/C101 Instrument-Software	Gas Storage Facilities	Discrete	Plants						($514,547)
258	Berger	Plants	Gas Other Storage Plant	E.0000068.017	MN/Wescott/V101/ V101A Recirc Loop	Gas Storage Facilities	Discrete	Plants						($456,498)
259	Berger	Plants	Gas Other Storage Plant	E.0000068.018	MN/Wescott/C201/C301 Slide Valve Re	Gas Storage Facilities	Discrete	Plants						($146,886)
260	Berger	Plants	Gas Other Storage Plant	E.0000068.019	MN/Wescott/Abandon Heater Skid	Gas Storage Facilities	Discrete	Plants						($62,932)
261	Berger	Plants	Gas Other Storage Plant	E.0000068.020	MN/Wescott/Vaporizer Bldg NFPA 68	Gas Storage Facilities	Discrete	Plants					($207,744)	
262	Berger	Plants	Gas Other Storage Plant	E.0000068.024	MN/Wescott/E104 Bypass Piping	Gas Storage Facilities	Discrete	Plants						($59,415)
263	Berger	Plants	Gas Other Storage Plant	E.0000068.029	MN/Wescott/Vaporization AreaStairwy	Other-Gas	Discrete	Plants						($332,901)
										($43,426,779)	**($56,702,699)**	**($120,062,356)**	**($90,030,311)**	**($124,615,469)**

Saint Paul Forest Street Bridge Crossing

Project Overview

Scope: Retire 500ft of 12inch steel that is currently suspended from the bridge. The new 12inch pipe will be directional bore along Forest St, crossing Phalen Blvd and then reconnecting to the existing 12inch pipeline west of Forest St.

Pressure System: 60 psig system

Project Status

Project Estimate Status: Complete
Design Status: In progress.
Construction: May 2024
In Service Date: 2024

Project Details

Project Need: The new 12inch HDD is required due to the existing vintage 12inch steel is suspended from the bridge preventing inspection and maintenance access without shutting down the highway. The City is planning a project to retire and relocate the Forest bridge.

Project Location

Cost

Project Cost: $1.8 M

Project Capital Expenditure Estimate: Estimated by project engineer based on the type of material, total footage of HDD and known utilities.

Review Process: The scope were reviewed by engineering and leadership to verify the route, materials and scope.

Saint Michael Reinforcement

Project Overview

Scope: Replace 11,600 feet of 4-inch steel pipeline with 6-inch steel pipe along Highway 35 (Fenning Ave NE and 30th St NE), in Saint Michael, MN.

Pressure System: Intermediate Pressure

Project Status

Project Estimate Status: Complete
Design Status: Preliminary
Construction: 2024
In Service Date: Planned For October 2024

Project Details

Project Need: Due to customer growth in the St Michael area, inlet pressure of the regulator station serving the Town is at its minimum system design pressure.

Project Location

Cost

Project Cost: $1.5M
Project Capital Expenditure Estimate: Project was estimated by Centralized Project Controls, with assistance from Gas Planning and Engineering.

Review Process: Reviewed with Engineering Leadership through Stage Gate 0, and the estimate was reviewed with Gas Planning and Engineering.

Discrete Capital Additions Peaking Plants
State of Minnesota Gas Jurisdiction ($ millions)

* Denoted projects that are described in detail in testimony.

Project Name	Description	2023 Forecast	2024 Test Year
Maplewood Fire Detection/Suppression Upgrades*	Replace the existing fire, gas, smoke detection system; demolish existing fire water suppression system and replace with mounding system to obtain compliance with NFPA 59A.	$0.0	$26.7
Wescott Fire Detection/Suppression Upgrades*	Replace the existing fire, gas, smoke detection system; abandon existing well sourced fire water pump and pump house and replace with new city water service from two city water locations connected to new pump house and underground piping extended to existing station fire suppression piping and distribution system to obtain compliance with NFPA 59A.	$0.0	$12.6
Sibley Truck Unloading Station*	Replace existing truck unloading system with above grade truck unloading and piping distribution system.	$0.0	$2.9
Maplewood Air Dryer*	Incorporate air dryer into vaporization system to improve gas quality to gas distribution standards and protect piping systems and valves from moisture that could affect performance and operations.	$0.0	$1.5
Wescott Inlet Meter Building	Remove concrete roof and support walls and replace with new foundation to support NFPA compliant building construction. Includes significant safety precautions during demolition to ensure safety and reliable plant operations.	$3.4	$0.0
Maplewood PAC 1&2 Compressor Controls and Air Conditioning	Install new electrical motor control center and cooling system components for continued operation of two existing compressors in good condition.	$2.7	$0.0

Wescott GT101/C101 Compressor	Closing out project to replace controls equipment for mixed refrigerant loop (MRL) compressor.	$1.6	$0.0
Wescott C101 Compressor Overhaul	Closing out project to remove of C101 compressor from housing and send to manufacturer for overhaul and replacement of parts.	$1.2	$0.0
Wescott Exchanger Platforms	Add maintenance work platforms to eliminate repeating scaffold construction and improve safe work area space during maintenance.	$0.0	$0.8
Wescott Pipe Integrity Verification	Closing out performance evaluation and hydrotesting to verify the integrity of our piping system at Wescott, as part of integrity maintenance development program.	$0.8	$0.0
Wescott C201/C301 Control Upgrades	Closing out upgrade the existing compressor controls to improve control of the boil off gas compressors.	$0.6	$0.0
Wescott WEG Skid Replacement	Replace water ethylene glycol skid, including valves, pumps, and piping.	$0.0	$0.6
Sibley Vaporization Project	Close-out costs related to plant vaporization refurbishment work.	$0.6	$0.0
Maplewood/Vaporization Project	Close-out costs related to plant vaporization refurbishment work.	$0.6	$0.0
Wescott C101 Instrumentation and Software	Upgrade C101 compressor instrumentation and software, including booster controls, instrumentation, interface screens, and related software.	$0.0	$0.5
Wescott Permanent Ethylene Tank	Install a permanent ethylene tank.	$0.0	$0.5

Wescott V101/ V101A Recirculation Loop	Upgrade V101A recirculation loop equipment.	$0.0	$0.5
Wescott Boiler Building Louvers	Install an upgraded ventilation system to exhaust gases.	$0.0	$0.4
Maplewood Truck Unloading Station	Close-out costs related to replacement of existing below grade truck unloading system with above grade piping transfer system.	$0.4	$0.0
Wescott Vaporization Area Stairway	Install new stairways in vaporization area to enhance safety and efficiency.	$0.0	$0.3
Wescott MRL Compressor Instrumentation Upgrade	Close-out costs related to installation of exchanger controls system to interface with new heat exchangers.	$0.3	$0.0
Wescott Instrument Air Communications	Install new communications from the instrument air compressors to the control room to provide critical line of site to compressor operation.	$0.0	$0.3
Wescott LNG/Cold Box Replacement	Close-out costs related to replacement of three heat exchangers inside the cold box unit: E-101, E-102, E-103.	$0.3	$0.0
Wescott MRL Compressor Instrumentation Control	Add new controls to MRL compressor.	$0.0	$0.3
Wescott Plant – Other	Other Wescott Plant projects.	$0.8	$0.6
Maplewood Plant – Other	Other Maplewood Plant projects.	$0.4	$0.0
Sibley Plant – Other	Other Sibley Plant projects.	$0.2	$0.0
Total		**$14.0**	**$48.4**

The following Schedules are considered
Not-Public in their entirety and contain Security Information.

- **Schedule 7**
  Maplewood Existing Fire Water System Assessment

- **Schedule 8**
  Maplewood and Wescott Project Budgets

- **Schedule 9**
  Wescott Existing Fire Water System Assessment

The above-noted Schedules included with the Not-Public version of testimony are each marked as "Not-Public Document in Entirety" because they contain Trade Secret Information and Security Information pursuant to Minn. Stat. § 13.37, subd. 1(b) and (a) respectively. The information is Trade Secret Information because it derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, certain portions of Schedules 7 and 8 are considered Security Information because the disclosure of the information is likely to substantially jeopardize the security of the discussed peaking plants against tampering, illegal disclosure, or physical injury.

Because the Schedules are marked Not-Public in their entirety, we provide the following additional information pursuant to Minn. Rule 7829.0500, subp. 3:

Schedule 7

1. **Nature of the Material:** Report on assessment of the existing fire water system capabilities at the Maplewood Propane/Air peaking plant.
2. **Author:** Jensen Hughes on behalf of Campos EPC
3. **Importance:** Contains not-public, proprietary, and security information
4. **Date the Information was Prepared:** October 12, 2021

Schedule 8

1. **Nature of the Material:** Budget information for the fire detection and suppression upgrade projects at the Maplewood and Wescott peaking plants.
2. **Author:** Xcel Energy, in conjunction with Campos EPC
3. **Importance:** Contains not-public, proprietary information
4. **Date the Information was Prepared:** Second Quarter, 2023

Schedule 9

1. **Nature of the Material:** Report on assessment of the existing fire water system capabilities at the Wescott LNG peaking plant.
2. **Author:** Jensen Hughes on behalf of Campos EPC
3. **Importance:** Contains not-public, proprietary, and security information
4. **Date the Information was Prepared:** October 18, 2021

Gas Systems O&M Costs by Category State of Minnesota Gas Jursidiction ($ millions)					
Cost Category	**2020 Actuals**	**2021 Actuals**	**2022 Actuals**	**2023 Forecast**	**2024 Budget**
Contract/COV	$12.5	$10.6	$11.5	$11.8	$12.7
Employee Expenses	$0.6	$0.5	$0.7	$0.5	$0.5
Facility Costs	$0.7	$0.6	$1.2	$1.3	$1.1
Labor	$20.7	$22.0	$22.7	$24.9	$25.6
Materials	$3.7	$4.2	$5.0	$4.6	$5.3
Misc Other	$0.2	($0.1)	$0.6	$2.4	($0.4)
Operational Credits	($6.0)	($5.5)	($6.1)	($8.7)	($6.9)
Regulatory & Other Fees	$0.2	$0.3	$0.4	$0.4	$0.4
Transportation	$2.4	$2.6	$3.8	$3.5	$3.7
Total	**$35.1**	**$35.3**	**$39.6**	**$40.6**	**$42.0**

Gas Systems O&M Costs by FERC Account State of Minnesota Gas Jurisdiction ($)					
FERC Account	**2020 Actuals**	**2021 Actuals**	**2022 Actuals**	**2023 Forecast**	**2024 Test Year**
733.0	53,590				
735.0	(99,206)	(418,974)	(128,253)	626,732	885,386
759.0	51,748	12,849			
813.0	1	2	4	754,471	748,982
824.0			2	1	
830.0				156	
834.0	17,201	22,784	85,352	104,845	100,158
841.0	1,108,929	647,842	1,195,791	1,615,428	1,389,659
843.1		12,011	212,019	108,804	159,794
843.2	70,662	79,476	110,195	264,629	211,274
843.3	(1,822)	4,583	46,778	1,711	
843.6	133,809	226,547	151,636	31,305	115,393
843.7	3,968	1,032	246		
843.8	463		638		
843.9	31,952	65,780	35,672	26,239	30,215
844.1	114,480	66,767			
844.2		120			
844.3	585,933	242,320	455,592	89,303	135,555
844.5		1,054	447	158	
846.2	18,420	147,005	306,396	337,616	342,174
847.1	20,785	(20,661)			
847.2	236,608	446,075	1,195,270	1,500,519	893,592
847.3	1,293,001	1,515,673	1,786,781	1,737,277	1,912,569
847.5	449	7,456	22,445	45,880	
847.8			3,385	350	
850.0	385,598	345,035	291,930	337,159	396,663
851.0	61,802	53,504	53,453	44,319	52,004
856.0	144,525	109,382	107,997	146,005	20,170
857.0	17,503	6,713	12,567	25,591	
859.0	175	18	33	12	
860.0		9			
863.0	63,061	68,007	105,486	57,265	6,088
865.0	9,429	3,310	18,130	4,238	
866.0			564		
870.0	4,001,088	4,683,766	5,951,308	6,785,195	6,169,128
871.0	2,604,662	2,672,599	2,690,955	2,790,728	2,727,927
874.0	9,717,943	10,499,469	9,672,561	11,319,870	13,191,732
875.0	356,674	295,797	265,440	183,009	334,031
876.0	1,545				
877.0	21,285	59,817	148,284	45,138	
878.0	(3,082,478)	(2,994,938)	(3,297,779)	(6,748,551)	(5,571,284)
879.0	1,198,165	1,163,081	1,144,774	997,697	850,380
880.0	8,390,958	5,710,308	5,436,010	7,812,291	7,667,027
881.0	49,287	522	275	5,234	
885.0	505,235	504,198	470,254	917,419	1,469,024
887.0	1,925,384	1,189,892	1,711,058	1,193,794	806,036
888.0	510,231	101,676			
889.0	139,242	308,569	485,005	357,906	190,818
890.0	325	46			
891.0	834	32,054	4,017	5,017	
892.0	3,864,722	4,564,506	5,311,913	4,192,170	2,995,209
893.0	382,173	2,627,440	3,239,914	2,832,268	3,755,569
902.0	11,234	6,241	4,586	394	
903.0	349	196	226	0	
904.0		(0)			
904.0	141,577	128,910	241,660	15,553	
905.0	3	7	19	7	
908.0	724				
909.0	1,099	232		254	
910.0	4	13	27	11	
912.0				222	
916.0	0	0	0	-	

Gas Systems O&M Costs by FERC Account State of Minnesota Gas Jurisdiction ($)					
920.0	27,106	25,267	36,623	23,999	7,848
921.0	7,405	4,521	6,518	3,383	981
922.0	-				
923.0	23,693	46	(8,033)	726	
925.0	483	-			
930.1	134	1,146	1,306	940	
930.2	16,509	36,352	17,685	24,212	31,097
931.0	250		1		
Total	**$ 35,140,911**	**$ 35,267,448**	**$ 39,605,162**	**$ 40,618,900**	**$ 42,025,196**