414 Nicollet Mall
Minneapolis, MN 55401

October 31, 2024

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: GAS UTILITY INFRASTRUCTURE COST RIDER
TRUE-UP REPORT FOR 2023, UPDATED COSTS FOR 2024,
REVENUE REQUIREMENTS FOR 2025, AND REVISED ADJUSTMENT FACTORS
DOCKET NO. G002/M-24-___

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the attached Annual Report and Petition for approval of recovery of updated gas utility infrastructure costs (GUIC) through the GUIC Rider for 2025.

Attached to this cover letter, we provide the required information as specified in Minn. R. 7829.1300 and Minn. R. 7829.0700, including to whom information requests should be directed.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Brandon Kirschner at brandon.m.kirschner@xcelenergy.com or Mary Martinka at mary.a.martinka@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA R. PETERSON
DIRECTOR, REGULATORY PRICING & ANALYSIS

Encls
cc: Service Lists

REQUIRED INFORMATION

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the Department of Commerce and the Office of the Attorney General. A summary of the filing has been served on all parties on the enclosed service lists.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Riley Conlin
Principal Attorney
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 216-9309

C. Date of Filing and Proposed Effective Date of Rate Factors

The date of this filing is October 31, 2024. The Company proposed the new 2025 GUIC Rider rate factors be effective March 1, 2026.

REQUIRED INFORMATION

D. Statute Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.1635 governs the Company's submission of a petition to recover gas infrastructure costs. The provision does not establish an explicit timing requirement for Commission action.

E. Utility Employee Responsible for Filing

Lisa R. Peterson
Director, Regulatory Pricing and Analysis
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
(612) 330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this proceeding:

Riley Conlin
Principal Attorney
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
riley.conlin@xcelenergy.com

Christine Schwartz
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Christine Schwartz at the Regulatory Records email address above.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER TRUE-UP REPORT FOR 2023, UPDATED COSTS FOR 2024, REVENUE REQUIREMENTS FOR 2025, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-24-___

PETITION, COMPLIANCE FILING, AND ANNUAL REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (Company), submits to the Minnesota Public Utilities Commission (Commission) this Petition, Compliance Filing, and Annual Report to request recovery of our 2025 Gas Utility Infrastructure Cost (GUIC) Rider revenue requirement.

For 2025, we request recovery of a GUIC Rider revenue requirement of approximately $27.2 million.[1] This request amounts to an impact of about $3.21 per month for an average residential natural gas customer's bill. Our request includes integrity management project costs that are consistent with the eligibility requirements set forth in the GUIC statute.[2] These costs are incurred to continue important infrastructure work that promotes the safety of our natural gas system.

Background

We are dedicated to operating a safe and reliable gas system for our customers. With aging gas infrastructure that runs primarily through high-density urban and suburban areas, it is of critical importance that the Company invests in assessing the integrity of our system and repairing and replacing problematic equipment. Integrity management

---

[1] Should the Commission grant the Company's request in our pending rate case to roll-in certain approved project costs into base rates, the 2025 GUIC revenue requirement would be reduced to about $15.0 million.
[2] Minn. Stat. § 216B.1635.

projects address our gas infrastructure's structural integrity, facilitating efficient assessments going forward, and ensuring a safer gas system that will reduce the likelihood of incidents within the community.

To promote the continued safety and reliability of our gas system through our GUIC work, since 2015 the Company has completed the replacement of more than 450 miles of high- and medium-risk, aging, corroded, and otherwise damaged gas distribution pipeline as well as the replacement of more than 19,700 aging distribution service lines.

Upcoming Transmission Integrity Management Programs (TIMP) work will include continued in-line inspections (ILI), programmatic replacement and maximum allowable operating pressure (MAOP) remediations, and casing renewals. Our MAOP project includes reconfirmation work and other costs required to meet new federal requirements.[3]

Upcoming major distribution renewal and replacement projects include the replacement of approximately 50 miles of poor performing distribution mains and 4,000 poor performing services. Beyond main and service replacement projects, upcoming Distribution Integrity Management Programs (DIMP) work will include distribution pipeline assessments and replacements, valve replacements, and casing renewals.

Impact of Current Natural Gas General Rate Case

The 2025 GUIC Rider revenue requirement presented in this filing may be affected by the Commission's decision in our currently pending natural gas rate case. The Company filed a natural gas rate case on November 1, 2023.[4] As a part of that rate case, the Company has proposed to roll all GUIC costs incurred between January 1, 2022 and December 31, 2023 into base rates at the time final rates are implemented.

The costs anticipated to be recovered through the GUIC Rider have not been included in the interim rate request of that filing and instead have been kept in our GUIC Rider. The Company reached and executed a Comprehensive and Unanimous Settlement Agreement (Settlement) with parties in the pending rate case such that we anticipate resolving all issues.[5] As of the date of this filing, the Settlement is pending Commission action.

---

[3] The new rule is the first of three parts of a Notice of Proposed Rulemaking issued by the Pipeline and Hazardous Materials Safety Administration in Docket No. PHMSA-2011-0023. The first part was published October 1, 2019 and carries progressive effective dates, the first of which was December 31, 2020. A greater discussion of this rule is provided in Attachment C.
[4] Docket No. G002/GR-23-413.
[5] Filed June 26, 2024 in Docket No. G002/GR-23-413.

As to not presume a result in that case, the revenue requirement presented in this proposal includes the costs from January 1, 2022 through December 31, 2023 that we have proposed to roll into base rates. The 2025 GUIC revenue requirement impact of these costs is approximately $12.2 million based on the capital structure last authorized in Docket No. G002/GR-21-678. We anticipate that the Commission will decide on our pending rate case before the conclusion of this docket. If the Commission approves the roll-in of costs to base rates, we will update this filing with revised 2025 revenue requirements reflecting the removal of any costs rolled into base rates.

Outline of Filing

The balance of this Petition is organized as follows:

- *Section I* – background of our GUIC Rider, including the applicable Minnesota State Statute, applicable standard of review, and GUIC Rider recovery as a part of our overall natural gas recovery
- *Section II* – a summary of the planned 2025 TIMP projects
- *Section III* – a summary of the planned 2025 DIMP projects
- *Section IV* – a summary of the planned 2025 Mandated Relocation projects
- *Section V* – demonstration that our request to recover costs through the GUIC Rider complies with the applicable standard of review and complies with previous Commission orders
- *Section VI* – discussion of our proposed 2025 revenue requirement, rate factor calculations, timing of rate implementation, status of GUIC Rider tracker account, and proposed tariff sheet and customer notice
- *Section VII* – support for our proposed capital structure and return on equity (ROE)
- *Section VIII* – a summary of performance metrics
- *Section IX* – information provided in compliance with Rate Case Settlement Agreement

To aid the review of this filing, we provide, as Attachment A, a compliance matrix setting forth the requirements of the enabling GUIC statute and relevant Commission Orders and directing readers to the part of the filing that addresses each requirement. We also provide an index of the included attachments as Attachment B to this filing.

PETITION

I. GUIC RIDER BACKGROUND

The GUIC Statute allows a utility to petition the Commission for the recovery of "gas utility infrastructure costs." As explained in this petition, TIMP and DIMP work make up the majority of "gas utility infrastructure costs" we request to recover through the GUIC Rider. The Commission has recognized that our TIMP and DIMP work is reasonable and in the public interest, noting:

> *The Commission concurs with the Department that the investments proposed for rider recovery […] meet the statutory requirements for rider recovery as gas utility infrastructure costs. These costs were incurred in the replacement or modification of existing facilities required by federal and state agencies. They were not included in Xcel's last rate case. And the costs are reasonable and prudent in view of the public safety purpose served by the TIMP and DIMP initiatives.*[6]

Recovery of costs through the GUIC Rider continues to be in the public interest, as it provides annual regulatory review of the Company's natural gas safety investments. The Commission signals continued regulatory support for investing in the safety of our natural gas system by allowing for efficient rider recovery of costs.

A. Applicable Minnesota Statutes

As mentioned above, the GUIC Statute allows a utility to petition for the recovery of "gas utility infrastructure costs." According to the GUIC Statute, GUIC costs can relate to two different types of "gas utility projects"—generally speaking, (1) replacement of natural gas facilities located in the public right-of-way by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the state of Minnesota or a political subdivision, or (2) replacement or modification of existing natural gas facilities as required by a federal or state agency.

The importance of safety-related cost recovery is also specifically mentioned in Minnesota's pipeline safety statutes. Minn. Stat. § 216B.16, Subd.11 states:

> *All costs of a public utility that are necessary to comply with state pipeline safety programs under sections 216D.01 to 216D.07, 299F.56 to 299F.64, or 299J.01 to 299J.17 must be recognized and included by the commission in the determination of just and reasonable rates as if the costs were directly incurred by the utility in furnishing utility service.*

---

[6] *See* Docket No. G002/M-15-808, ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES at 6 (August 18, 2016).

As the Commission has previously recognized, the Company's TIMP and DIMP activities are precisely the type of expenditures for which Minn. Stat. § 216B.1635 authorizes recovery. With this request, the Company asks the Commission to allow continued recovery of our projected TIMP and DIMP expenses for 2025. This year, our TIMP and DIMP plans include the same programs that were included and approved in our 2024 GUIC Rider request.

The GUIC Statute explicitly authorizes the timely recovery of GUIC expenditures through a rider mechanism. As stated in the statute, the legal standard of review for this petition is:

> *Upon receiving a gas utility report and petition for cost recovery under subdivision 2 and assessment and verification under subdivision 4, the commission may approve the annual GUIC rate adjustments provided that, after notice and comment, the costs included for recovery through the rate schedule are prudently incurred and achieve gas facility improvements at the lowest reasonable and prudent cost to ratepayers.*[7]

The Company's revenue requirement reflects the impact of ongoing integrity management projects already approved by the Commission in previous GUIC Rider filings. We are not proposing a change in rate of return with this request and support using the return on equity, capital structure, and rate of return agreed to in the settlement unanimously agreed to in our last natural gas rate case.

B. GUIC Rider as a Part of Overall Gas Utility Cost Recovery

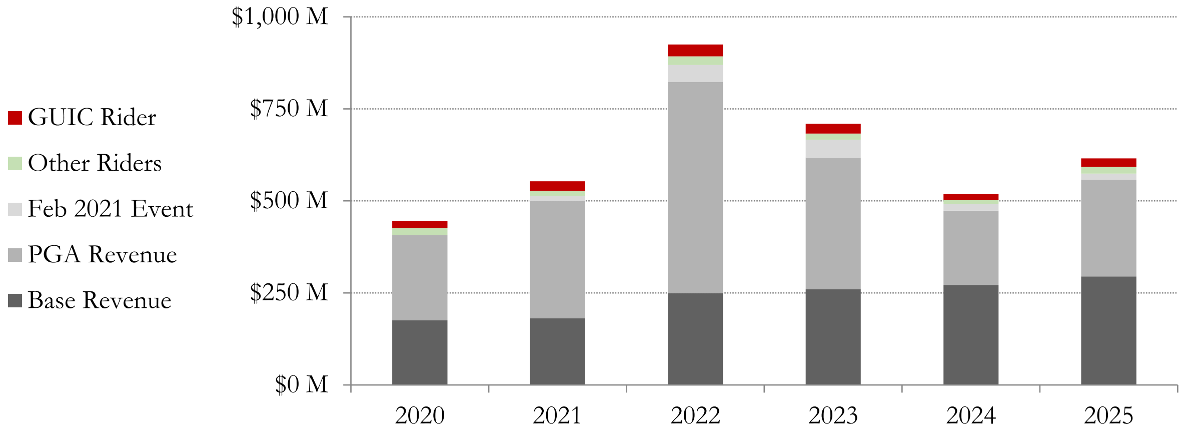
The recovery of GUIC Rider revenue requirements is a critical component in the Company's gas utility business and facilitates construction and assessment activities that help keep the gas system operating safely and efficiently. However, the total GUIC Rider revenue requirement related to integrity management project work represents only a portion of the overall gas utility recovery. At a high level, the Company's gas utility recovery can be broken down into four components. These components are:

- Base rates recovery, stemming from the approved revenue requirement from the last general gas rate case,
- Fuel revenues (through the PGA and the February 2021 Event Surcharge),
- GUIC Rider annual revenue requirement,
- Other riders.

To provide context as to how the GUIC Rider fits into the Company's total gas utility recovery, Figure 1 below shows the total gas utility revenue collections by recovery mechanism.

[7] Minn. Stat. § 216B.1635 subd. 5.

Figure 1
Annual Revenue Collections by Recovery Mechanism



	2020	2021	2022	2023	2024	2025
GUIC % of total	4.3%	4.6%	3.5%	3.7%	3.2%	3.7%
Earned ROE	7.2%	3.9%	7.1%	5.5%		

The GUIC Rider represents 3.7 percent of total bill collections forecasted in 2025. In Figure 1 above, we also provide the earned ROE as reported in our jurisdictional annual reports. The reported earned ROEs include the costs and revenues across all the shown recovery methods.

II. TIMP PROJECTS

We established our TIMP to assess and improve the safety and reliability of our gas transmission system, which includes approximately 65 miles of transmission pipeline in Minnesota. Our TIMP complies with federal regulations by identifying risks, systematically performing health and condition assessments, and evaluating and prioritizing preventative or corrective actions to mitigate identified risks and threats. Our TIMP focuses on giving the Company a comprehensive understanding of the health and condition of its gas transmission pipelines, while assigning higher priority to those located in highly populated areas.

The Company currently has three major TIMP initiatives under way.

- Transmission Pipeline Assessments,
- Programmatic Replacement and MAOP Remediation Program,
- Casing Renewals.

We also note that work on the Automatic Shut-off Valves and Remote-Controlled Valves was completed in 2022, with no future work currently planned. Table 1 below shows the estimated 2025 TIMP project costs.

Table 1
2025 Estimated TIMP Project Costs ($ Millions)

Program	2025 Capital[8]	2025 O&M
Transmission Pipeline Assessments[9]	$1.0	$0.6
Programmatic Replacement / MAOP Remediation[10]	$3.9	$0.1
Casing Renewal	$11.1	$0.0
Total 2025 TIMP Expenditures	**$16.0**	**$0.6**[11]
Total 2025 Minnesota TIMP Revenue Requirements	**$3.4**	**$0.5**

Project descriptions, scopes of work, estimated costs and in-service dates for specific TIMP projects are provided as Attachments C, C1, and C2. We also provide a brief explanation of new federal regulations that may influence future TIMP projects. The capital expenditure costs and forecasted costs for incremental TIMP activities between March 2012 and December 2029 are included in Attachment F. Attachment G shows the development of 2025 revenue requirements for TIMP activities, based on the capital expenditures referenced in Attachment F.

A. Transmission Pipeline Assessments

Transmission pipeline assessments are an ongoing program, which began in 2002, to assess the health and condition of our gas transmission lines. Federal regulations require assessment of gas transmission pipelines using ILI, pressure testing, or direct assessment.[12] Regular assessment of pipelines is based on the health and condition of the assets as well as an evaluation of the risks and threats that may cause pipeline damage.

The Company has completed requirements related to High Consequence Area (HCA) Baseline Assessments,[13] and is now focusing on the re-assessment of pipelines in HCAs as well as assessing remaining transmission pipe beyond HCAs. Federal transmission rules published in 2019 require that Moderate Consequence Areas must be assessed initially by July 3, 2034 and then must be reassessed at least once every 10 years thereafter or sooner based on the risks and threats to the pipeline segment. These assessments provide important information about the conditions of the

---

[8] Estimated capital costs include estimated removal costs. Details can be seen in Attachment C1.
[9] Includes Sleeve Repairs.
[10] Includes Transmission Rule costs.
[11] Column does not sum due to rounding.
[12] The requirements are further defined in the Company's TIMP manual.
[13] Federal requirements stipulated that all pipelines in HCAs needed to be assessed by December 17, 2012. See 49 CFR Part 192.921.

Company's pipelines, including the existence of internal and external corrosion and other anomalies.

When performing gas transmission line assessments, the Company conducts ILI as a first preference. There are advantages to using ILI compared to alternative assessment methods. First, the pipelines need not be taken out of service while the inspection is in process. Second, ILI provides the most comprehensive profile of the integrity of a pipeline and can assess for multiple threats. Third, ILI technology allows for assessment of longer distances with one inspection run. Other approved assessment methodologies (pressure testing or direct assessment) only assess for limited threats and are usually performed on relatively short pipe segments. After an initial capital investment to prepare a pipeline for an ILI tool, subsequent assessments will be performed using ILI as an operations and maintenance (O&M) cost.

The forecasted capital and O&M costs for assessments included in our previous GUIC Rider filings are shown in Table 2 below.

Table 2
GUIC Transmission Pipeline Assessments[14] ($ Millions)

Filing	Assessment (Miles)	Capital Expenditures	O&M Expenditures
2016 (15-808)	10.5	$4.9	$0.0
2017 (16-891)	13.7	$1.6	$1.1
2018 (17-787)	20.9	$0.3	$1.5
2019 (18-692)	15.8	$1.0	$2.9
2020 (19-664)	26.2	$3.6	$1.7
2021 (20-799)	13.5	$1.5	$1.7
2022 (21-765)	3.2	$0.6	$0.6
2023 (22-578)	7.7	$0.3	$0.6
2024 (23-457)	20.6	$0.3	$1.3
2025 (24-___)	13.8	$1.0	$0.6

As shown in Table 3 below, the Company expects to complete three ILI reassessment projects in 2025.[15]

[14] Numbers in Table 2 reflect estimated mileage and expenditure amounts as shown in our original 2016 through 2025 GUIC Rider filings for each year and may differ from actual amounts due to program modifications and scope changes occurring after the initial filings.
[15] Assessments are required every seven years according to Subpart O – Gas Transmission Pipeline Integrity Management 192.939.

Table 3
Transmission Integrity Assessments[16]

Number of Projects								
	2015-2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
ILI	7	2	2	2	2	3	3	**21**
Pressure Test	3	0	0	0	0	0	0	**3**
Derate[17]	1	0	0	0	0	0	0	**1**
Direct Assessment	2	0	1	1	0	0	0	**4**
Total	13	**2**	**3**	**3**	**2**	**3**	**3**	**29**
Assessed Mileage								
	2015-2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
ILI	31.3	16.1	3.2	3.2	7.7	20.6	13.8	**95.9**
Pressure Test	3.2	0.0	0.0	0.0	0.0	0.0	0.0	**3.2**
Derate	5.8	0.0	0.0	0.0	0.0	0.0	0.0	**5.8**
Direct Assessment	6.9	0.0	10.3	0.0	0.0	0.0	0.0	**17.2**
Total	**47.2**	**16.1**	**13.5**	**3.2**	**7.7**	**20.6**	**13.8**	**122.1**

Beyond this year, we are forecasting annual costs associated with transmission pipeline assessments between $1.4 million and $2.5 million from 2026 through 2029. The costs incurred will likely be a combination of capital expenditures and O&M expenses, depending on the type of work being performed. Based on the current assessment plan, the Company expects to complete two to three projects each year in the 2026 through 2029 timeframe.

B. Programmatic Replacement and Maximum Allowable Operating Pressure Remediation

In 2017, the Company began work on the Programmatic Replacement and MAOP Remediation Program. The MAOP initiative strives to meet the requirement to have traceable, verifiable, and complete (TVC) records of a pipeline's and asset's MAOP. Through the initiative, the Company is validating existing MAOP records for our transmission pipelines and assets and remediating any gaps in such records.[18] A new federal transmission rule was published on October 1, 2019. This rule is the first of

[16] 2024 and 2025 amounts are estimates based on expected work scopes. Numbers may change as actual work is completed.
[17] A derate project involves lowering the line's maximum allowable operating pressure to reduce risk and reclassify the pipeline as distribution. The project noted for 2019 was for the Eagan Line.
[18] There are about 300,000 miles of natural gas transmission pipelines in the United States, and a significant portion of these lines were installed prior to federal pipeline safety regulations being codified in 1970. Therefore, it is expected that there will be gaps in MAOP records.

three rules that originated from the Notice of Proposed Rulemaking (NPRM) published in March of 2016 under Docket No. PHMSA-2011-0023. MAOP reconfirmation is a key focus area of the rule which provides prescriptive code requirements regarding the timeline, methodology, applicable pipeline segments and assets, and historical documentation necessary for MAOP reconfirmation. These PHMSA requirements regarding records are a critical safety effort. We believe recent changes in the requirements necessitate the work that we have undertaken and show that the costs incurred are eligible for GUIC Rider recovery in full.

There are five MAOP projects scheduled to be completed in 2025. The 2025 MAOP projects include the following work:

- Design work for pressure testing a portion of transmission line, with work extending in to 2026;
- Pressure testing three regulator stations;
- Completing material verifications for stations and mainlines where pressure testing has been documented but not materials documentation;
- Replacing a short section of pipeline;
- Completing pressure testing on a section of pipeline started in 2024.

We anticipate capital expenditures of $3.9 million of capital expenditures and $0.1 million of O&M expenditures for the 2025 work. Beyond 2025, we expect future annual expenditures on MAOP replacement projects of about $2.6 million from 2026 through 2029.

C. Casing Renewals

The casing renewal project is a multi-year program which started in 2021. The objective of this project is to mitigate risks by renewing pipeline or installing equipment that allows ongoing testing to ensure isolation of pipelines from casings. Pipelines were installed inside casings to protect the pipe from a variety of forces. Casings were routinely used in a variety of situations, including under roads and railroads. Improved pipeline design has mostly eliminated the use of casings in modern gas construction. The Company has identified several instances where it is unknown whether a pipeline carrying gas is or is not isolated from the casing. Pipelines that are not isolated from the casing can create a corrosion risk and lead to pipeline failure. Identifying and remedying these instances are an important safety effort, and we believe the costs we will incur are eligible for GUIC Rider recovery in full.

The Company's Gas Standards Manual section 9.9.9 and 49 Code of Federal Regulations (CFR) § 192.467 require the ability to test for isolation of a pipe and casing. Both the federal code and our standards manual require the Company to take pipe-to-soil and casing-to-soil readings annually for all metallic carrier pipe installed in a metallic casing, with the purpose of determining whether the two pieces of pipe are in contact. If testing shows the pipe and casing are isolated, the casing is added to the annual test leak survey and will be monitored and maintained over time. If testing shows no isolation, the casing will be renewed under this project.

This project started during the 2021 construction season and will continue until all casing risks on the program list have been mitigated. We anticipate completing construction on one casing project in 2025. This project was initially planned for completion in 2024 but was moved to 2025 completion based on constructability reviews. The anticipated capital expenditures for 2025 are $11.1 million. We anticipate incurring an additional $1.9 million in capital expenditures for casing renewal work in 2026, with no additional work planned for 2027 through 2029.

III. DIMP PROJECTS

The Company's DIMP is grounded in federal rules issued by PHMSA with a goal to ensure safe and reliable gas delivery to our customers.[19] The DIMP rules are intended to help gas system operators identify, prioritize, and evaluate risks; identify and implement measures to address those risks; and validate the integrity of the gas distribution system.

To date, two major DIMP initiatives have been completed—Distribution Pipeline Data and Federal Code Mitigation. The Company currently has five major ongoing DIMP initiatives under way.

- Poor Performing Main Replacement,
- Poor Performing Service Replacement,
- Distribution Pipeline Inspection and Replacement,
- Distribution Valve Replacement Project,
- Casing Renewals.

In addition to our five major ongoing initiatives listed above, we also have sewer and gas line conflict investigation work planned for 2025. The main planned work for our sewer and gas line conflict remediation plan was completed in 2019. However, the Company has identified a number of additional inspections that will be completed in 2024. The Company plans to increase legacy clearing efforts in high-risk locations, including approximately 3,500 services in 2025.

Table 4 below shows the estimated 2025 DIMP projects costs.

---

[19] *See* 49 CFR. 192, Subpart P. PHMSA is a Department of Transportation agency created in 2004, responsible for developing and enforcing regulations for the safe, reliable, and environmentally sound operation of the Unites States' 2.6-million-mile pipeline transportation.

Table 4
2025 Estimated DIMP Project Costs ($ Millions)

Program	2025 Capital[20]	2025 O&M
Poor Performing Main Replacements	$19.5	$0.0
Poor Performing Service Replacements	$6.5	$0.5
Intermediate Pressure (IP) Line Assessments / Replacements	$0.0	$0.3
Sewer and Gas Line Conflict Investigation	$0.0	$1.3
Distribution Valve Replacement Project	$0.5	$0.0
Casing Renewal	$3.2	$0.0
Total 2025 DIMP Capital Expenditures and O&M	**$29.7**	**$2.1**
Total 2025 Minnesota DIMP Revenue Requirement	**$15.0**	**$1.5**

Project descriptions, scopes, estimated costs, and in-service dates for specific DIMP projects are provided in Attachments D, D1, D2(a), and D2(b). Attachment F reports the capital expenditure forecast for incremental DIMP activities between August 2012 and December 2029. Attachment H shows the development of 2025 revenue requirements for DIMP activities, based on the capital expenditures referenced in Attachment F.

A. Poor Performing Main and Service Replacements

Under 49 CFR Part 192.1007(d), the Company must determine and implement measures designed to reduce the risks from failures of its gas distribution pipeline. As a result, the Company uses subject matter expertise, historical leak data, and industry information to identify risk factors that may lead to gas pipeline leaks or failures. The annual replacement levels of high- and medium-risk pipe are based on these factors. In this filing we are requesting $19.5 million in costs related to Poor Performing Mains and $7.0 million in costs related to Poor Performing Service Replacements. The Company deems a main or service line to be high- or medium-risk through our risk ranking methodology as well as monitoring industry trends and issues. The goal of the Company's risk analysis is to anticipate issues and proactively address them before they become problems on the system. Improvements in data quality and Company processes are aiding the transition to a more proactive approach which benefits customers. Work undertaken systematically reduces costs compared to work undertaken in a reactionary or immediate threat mode. The Company monitors and reviews the leak history of pipe material types and year of installation. Trends of

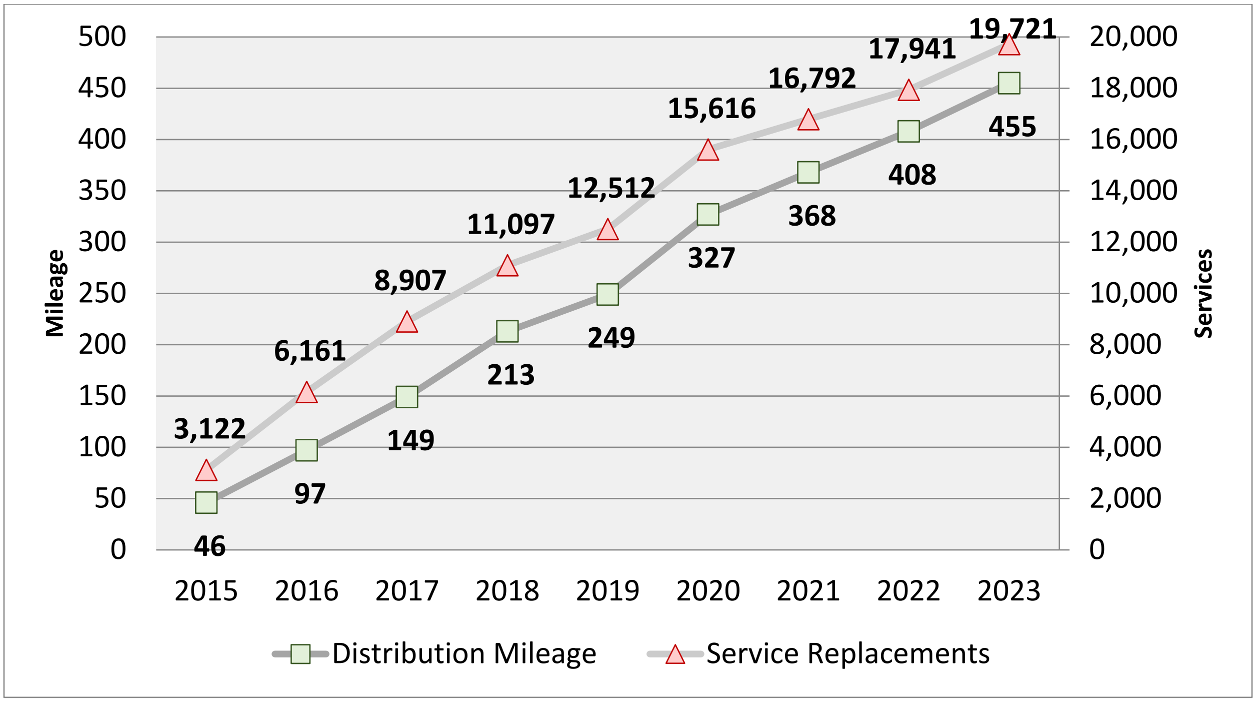
---

[20] Estimated capital costs include estimated removal costs. Details can be seen in Attachment D1.

increasing leak ratio or cause associated with certain pipe types are studied further to determine if proactive action is required.

Figure 2 below illustrates the Company's achievements in integrity-related main and service distribution replacement.

Figure 2
Cumulative Gas Distribution Pipeline Installation and Service Replacements[21]

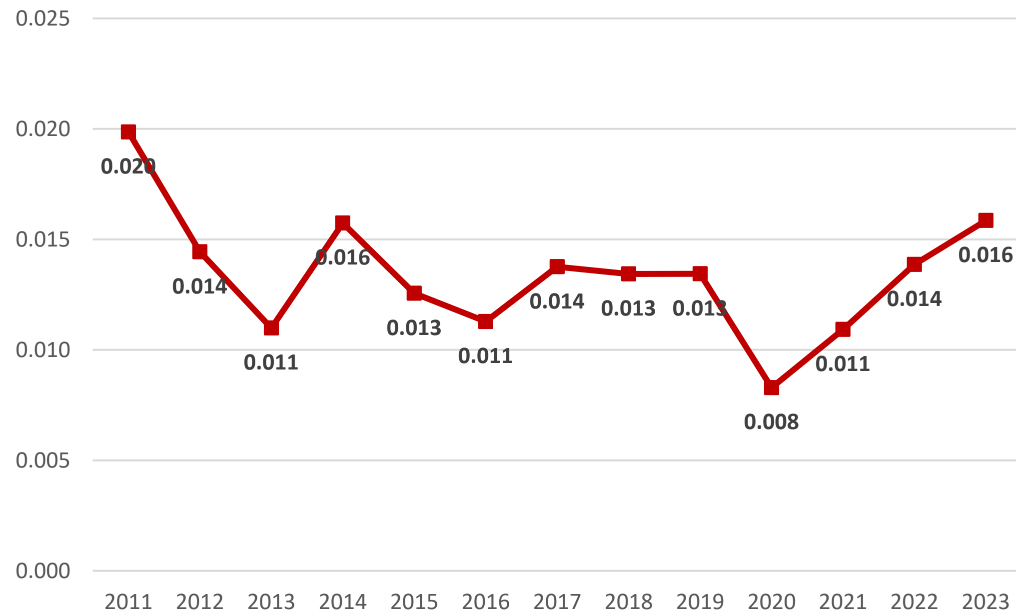


The Company continually collects data to help identify and remove distribution pipe segments that are most susceptible to failure. One of these data collection methods is periodic leak surveys to monitor system integrity and remediate leaks that have the potential to result in an event. Figure 3 below reflects leak data submitted to the United States Department of Transportation for the years 2011 through 2023. As evidenced in Figure 3, the performance of the Company's distribution system has gradually improved, as measured by a decline in the leak rate per mile of main from 2011 to 2023.[22]

---

[21] Please note that the number of 2016 Service Replacements has been corrected and does not tie to the same chart in previous-year filings. This change also affects the cumulative totals in subsequent years.
[22] Leak rates can occasionally increase year over year due to variances in areas where work is focused each year.

Figure 3
Distribution Mains Leak Rate
(Per Mile of Main)



Beyond 2025, our estimated future annual capital expenditures for the poor performing mains project are between $20.1 million and $21.5 million from 2026 through 2029. The estimated future annual capital expenditures for the poor performing services project are between $6.7 million and $7.2 million from 2026 through 2029. Replacement work will require design and construction resource procurement and deployment. The Company does not expect to incur significant O&M costs for the project, as the costs of service transfers are a capital cost when the transfer is completed as the result of, and in conjunction with, another capital project.

B. Distribution Pipeline Inspection and Replacement

Distribution pipeline inspections and replacements are part of an ongoing program that involves the regular inspection and replacement of high- and medium-risk segments of pipeline to satisfy the federal pipeline safety regulations set forth by PHMSA rules.[23] The asset health data collected from these inspections will be used to develop plans for additional mitigation actions as needed to protect public safety. The work planned for 2025 includes underwater assessments of pipeline river crossings, indirect surveys,

[23] *See* 49 CFR Part 192.921 (a). The rule requires an operator to assess the integrity of the line pipe in each covered segment by applying one or more of the approved methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment.

and follow-up digs. All the work planned is considered O&M work. We expect no capital expenditures and O&M expenditures of about $0.3 million in 2025 for the line assessment and replacement work.

As shown in Table 5 below, the Company expects to complete four direct assessment projects in 2025. When adding the mileage for assessments already completed from 2016 to present, the Company expects to assess a total of about 181 miles of distribution pipeline from 2016 through 2025.

Table 5
Distribution Pipeline Integrity Assessments[24]

	2016-2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Pressure Test	1	0	0	0	0	0	0	**1**
Direct Assessment	5	1	4[25]	4	5	6	4	**29**
River Crossing Assessment	0	0	0	13	0	5	16	**34**
Total	**6**	**1**	**4**	**17**	**5**	**11**	**20**	**64**
	2016-2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Pressure Test	2.4	0.0	0.0	0.0	0.0	0.0	0.0	**2.4**
Direct Assessment	47.3	36.2	22.8	24.3	19.2	12.2	16.4	**178.4**
Total	**49.7**	**36.2**	**22.8**	**24.3**	**19.2**	**12.2**	**16.4**	**180.8**

There are no pipeline replacement projects planned for 2025. Beyond 2025, we have no capital expenditures planned, although assessments will continue being performed to direct future projects. We anticipate annual O&M costs of about $0.3 million from 2026 through 2029 to complete the assessment work.

C. Sewer and Gas Line Conflict Inspection

The Company's Sewer and Gas Line Conflict Remediation program was a major DIMP initiative that sought to identify conflicts between sewer and gas lines that are low probability but high consequence. The program was initially launched as a 10-year effort in 2010 in response to an incident where a sewer cleaning contractor working in Saint Paul perforated a natural gas main that intersected the sewer line, resulting in a

[24] 2024 and 2025 amounts are estimates based on expected work scopes. Numbers may change as actual work is completed.
[25] Number includes two excavation projects based on survey results in 2014 and 2020.

fire, property damage, and injury. The program initially was completed in 2019, and over that time the Company saw conflict rates decrease from 0.20 percent to 0.02 percent. During the program the Company performed about 250,000 sewer line inspections and cleared around 150 conflicts.

Due to knowledge-sharing with other utilities and identification of new risk factors significant to identifying potential new sewer and gas line conflict locations, the Company is continuing the conflict inspection process to increase our legacy clearing efforts in high-risk locations. The Company anticipates completing the inspection of 3,500 services for conflicts in 2025. The Company estimates incurring $1.25 million of O&M costs in 2025 to complete the inspections. There are no anticipated capital expenditures for the project in 2025. The sewer and gas mitigation work is anticipated to continue beyond 2025 and we anticipate incurring annual O&M costs of about $1.3 million to $1.5 million from 2026 through 2029.

D. Distribution Valve Replacement Project

The distribution valve replacement project is an ongoing project focusing on the replacement adding, replacing, or otherwise rehabilitating existing distribution valves. This work is in response to the Company's obligation under 49 CFR Part 192.1007(d). We estimate that the annual capital expenditures for distribution valve replacements will be about $0.5 million in 2025.

One aspect of the program will focus on existing distribution system isolation valves which have become inaccessible, inoperable or are beyond their useful life. The Company determines the need for a valve replacement based on valve conditions and locations. Initially, the Company anticipated valve replacement work ending in 2019. However, during period maintenance and operating procedures, additional valves were identified as inoperable. The Company currently estimates a total of 30 distribution valves will be replaced in the South Metro and Southeast areas. Of these valves, six are expected to be replaced in 2025 with the remaining to be replaced in 2026 through 2029. Replacing these valves will allow the Company more options to isolate sections to address an emergency or system incident, while impacting the smallest number of customers.

A second aspect of this project is the installation of new valves. After a review in 2020 determined that new valves were needed to reduce shutdown times during emergencies, we began new valve installations in 2021. The Company anticipates installing 24 new valves in 2025, with seven additional valves to be installed in future years.

We estimate that the capital expenditures for all distribution valve replacements and the installation of new values in 2026 through 2029 will be about $0.6 million annually.

E. Casing Renewal

As with the transmission casing renewal project, this work is being done in accordance with the Company's Gas Standards Manual section 9.9.9 and 49 CFR § 192.467. The casing renewal project is a multi-year program that started in 2021. This is a comparable project to the TIMP casing renewal project discussed earlier, but instead focused on distribution pipelines. Under this project, the Company isolates pipes and casings that are determined to be in contact with one another (or unable to take readings), mitigates leakage risk for sites that indicate the presence of corrosion or where testing has not occurred, and replaces pipe where it is not possible to test or isolate the pipe. Metallic pipes need to remain isolated from each other to reduce corrosion risk.

This project shall continue annually until all casings risks on the program list have been mitigated. We anticipate completing five casing renewals in 2025, with associated capital expenditures of $3.2 million. Beyond 2025, we anticipate completing an additional 15 casing renewals, with annual capital expenditures of about $5.0 to $5.4 million from 2026 through 2029.

IV. MANDATED RELOCATIONS

The mandated relocations program is dedicated to moving 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. The Company must invest capital to achieve these relocations and establishment of service via infrastructure at a different location.

We began including mandated relocations as a GUIC project in 2021. We believe mandated relocations to move facilities that are in direct conflict with street expansions within public rights-of-way is the type of program specifically considered by the statute. One of the two definitions of a project to be included in the GUIC is:

> …*replacement of natural gas facilities located in the public right-of-way required by the construction or improvement of a highway, road, street, public building, or other public work by or on behalf of the United States, the state of Minnesota, or a political subdivision[.]*[26]

The Company has been notified of two new mandated relocation projects occurring in 2025. These projects are planned for the Hugo Line in White Bear Lake and a reconstruction project in Inver Grove Heights.

In addition to the discrete projects we have already been notified of, the Company also expects to complete several other mandated relocation projects in 2025, as additional

[26] Minn. Stat. § 216B.1635 subd. 1.c.1.

infrastructure work is planned by budgets for routine relocation projects that arise during each year. These projects typically have a cost less than $0.3 million.

We estimate that the total capital expenditures for mandated relocations we are asking to recover in the GUIC Rider will be approximately $17.2 million in 2025. Table 6 below shows the estimated mandated relocation project costs.

Table 6
2025 Estimated Mandated Relocation Project Costs ($ Millions)

Mandated Relocation Program	2025 Capital	2025 O&M
Total 2025 Capital Expenditures and O&M	$17.2	$0.0
Total 2025 Minnesota Revenue Requirement	$9.4	$0.0

The amounts included in the 2025 GUIC Rider Petition are based on historical data and anticipated costs. The budget for routine main relocations is based on the average of 2022 and 2023 actuals escalated by the corporate inflation rate.[27] Further, inputs and assumptions regarding inflation factors are used to determine the assumed cost increases or decreases. Beyond 2025, we estimate that capital expenditures for mandatory relocations will be about $18.1 to $18.9 million annually from 2026 through 2029.

Project descriptions, scopes, estimated costs, and in-service dates for specific mandated relocation projects are provided in Section VI of Attachment D. Greater details on the mandated relocation projects are also provided in Attachment E. Attachment F reports the total capital expenditure forecast for mandated relocation activities through December 2029. Attachment H shows the development of the 2025 revenue requirements for DIMP and mandated relocation activities, based on the capital expenditures referenced in Attachment F.[28]

V. COMPLIANCE WITH COMMISSION ORDERS AND STATUTES

A. GUIC Rider Promotes Safety and Reliability and is in the Public Interest

The GUIC Rider continues to be in the public interest, as it enables ongoing improvements that help ensure the safety and reliability of the Company's gas utility assets. As the Commission has recognized, by proactively addressing system risks, the Company can systematically and efficiently conduct critical work. Indeed, working from a proactive stance allows the Company to take advantage of improved economies of scale, engage in regional

[27] About 2.4 percent.
[28] Mandated relocations are shown with DIMP in Attachments H, O, and P.

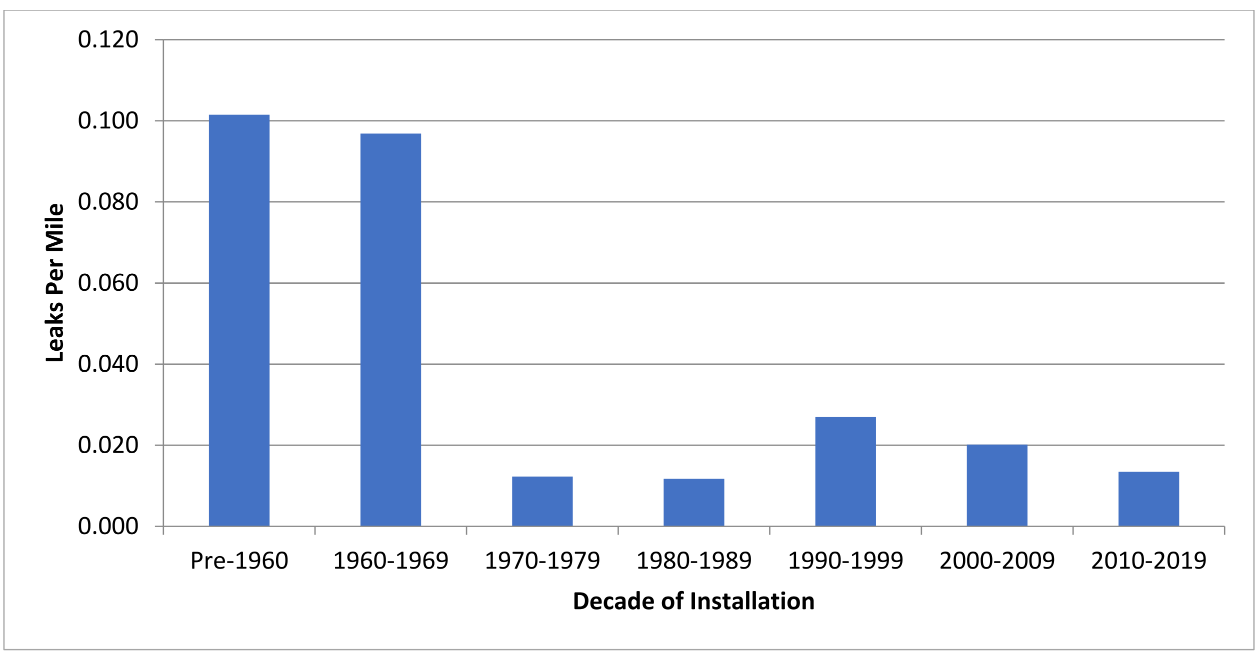
planning, minimize inconvenience to impacted communities, and efficiently deploy resources.

The public and customer benefits of increased safety and reliability that are delivered through integrity management project work are significant and ongoing, but continued efforts are needed. For instance, the needs of our aging infrastructure, particularly in densely populated areas, are addressed through our integrity management work. Thus, integrity management project work reduces the risks of major catastrophes in the event of a failure.

1. *Addressing Aging Assets*

Federal regulation requires pipeline operators to assess the integrity of their pipelines based on threats to which the pipeline is susceptible. The characteristics of the Company's gas utility assets, including material types and construction methods used at the time of installation, introduce varied levels of risk. For example, steel pipes that were installed prior to the requirements or implementation of effective cathodic protection are prone to corrosion and have a higher risk of failure. Older assets also have a higher risk of material or construction flaws. A demonstration of this fact is shown in Figure 4 below. In this figure, leak rates per mile are shown for each decade of installation for our coated steel distribution pipelines.

Figure 4
MN Coated Steel Leak Rate by Install Decade
Five-Year Average (2019-2023)

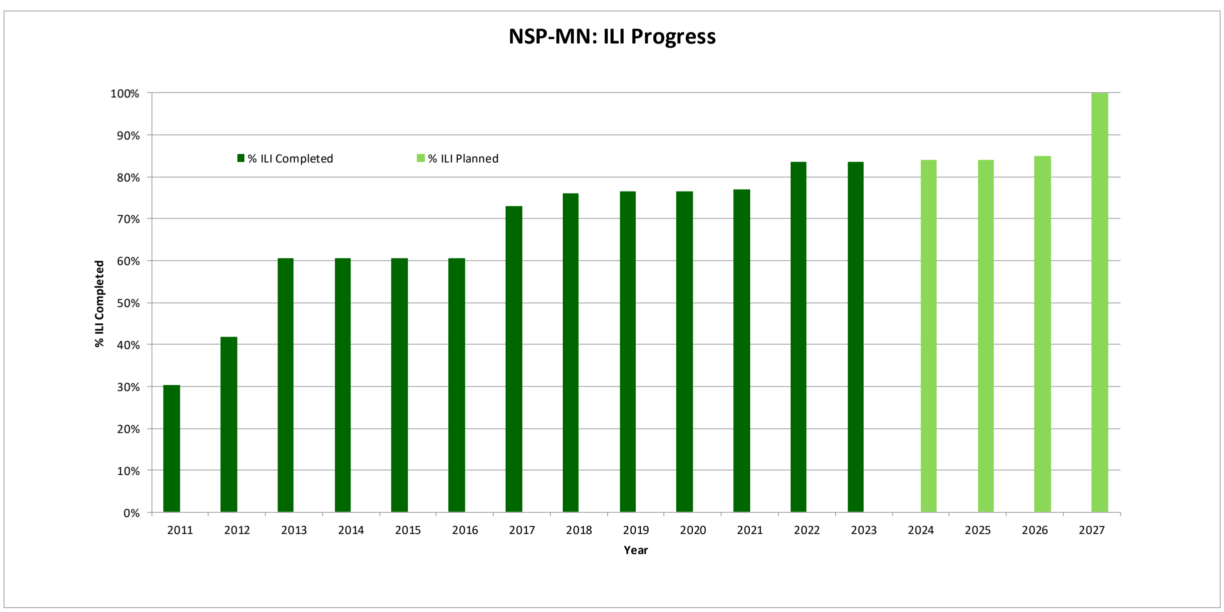


As can be seen, the leak rate for pipe installed in more recent decades is consistently lower than the leak rate for pipe installed earlier. While age alone does not indicate an imminent risk of failure, it is a predictive factor, and we must address risks posed by legacy construction techniques and materials. Leak rates for steel installed in 2020 through 2023 were not included in Figure 4 above, as a five-year average will not be available until 2025. There were three underground, non-excavation damage leaks recorded for steel installed between 2020-2023, corresponding to a three-year leak rate of 0.05 leaks per mile.

To assess aging gas transmission assets, the Company primarily uses ILI due to its superior ability to provide detailed information regarding the current pipeline condition without having to remove the line from service. Not all pipelines can be assessed by ILI due to limitations in the capabilities of available ILI tools. For example, the same ILI tool may not be able to be used on the entire length of a pipeline if the pipe diameter varies.

As shown in Figure 5 below, approximately 84 percent of the Company's gas transmission system that is planned to be assessable using ILI tools has been assessed. The Company's current assessment plan projects 100 percent of transmission pipelines that are feasible to be assessed by ILI tools will be ILI compatible by 2027. The Company has started using robotic ILI tools, which has expanded the transmission pipelines that can be assessed by ILI.

Figure 5
Transmission System ILI Assessment Progress[29]



[29] This chart does not include recently installed pipelines that are not yet due for their baseline assessment after being placed in-service.

2. Safety and Population Density

Many communities with older gas utility assets have grown significantly since the gas system in that area was initially built. Increased population density brings with it a higher risk of catastrophic consequences in the event of a failure. Population density is a critical focus of determining the criticality of pipeline work and is a factor in our risk modeling processes that help us prioritize work in high-density areas.[30] Pipeline assets, both transmission and higher-pressure distribution lines, require increased effort and related expense as the Company works to help ensure the safe and reliable operation of these systems.

3. Risk Assessment Methodology

The Company evaluates the threats to our pipeline that may pose a safety or reliability risk. Pipeline asset information from existing records, operating data, and input from subject matter experts is initially used to identify events or conditions that could cause or increase the likelihood or consequence of pipeline failure. This risk evaluation process provides information to facilitate decisions about the prioritization of health and condition assessments, the frequency of assessment, which assessment methodology is most appropriate, and in certain cases information to substantiate the need for replacement of an asset. The Company provides detailed explanations of our risk assessment processes in Attachments C and D.

The Company continues to assess our assessment processes to ensure that they are as useful as possible. The actual results of the risk assessments can be found in Attachments C2, D2(a), and D2(b).

B. GUIC Rider Activities are Reasonable and Prudent

The GUIC statute requires that our annual filing include information regarding the reasonableness and prudency of our integrity management project costs incurred.[31] Through stringent oversight processes and a contract and charge review process, the Company can ensure that costs are tracked and are reasonable in comparison to forecasted amounts. The Company looks for many opportunities to control costs, and the following discussion will highlight these efforts undertaken by the Company to ensure the reasonableness and prudency of our integrity management project costs.

The Company believes integrity management project work is prudent, regardless of the recovery mechanism used. The primary advantages of a rider mechanism are the added flexibility, frequency of regulatory review, and promptness of recovery. Rider recovery

---

[30] High-density areas are also referred to as high consequence areas in PHMSA guidelines.
[31] Minn. Stat. § 216B.1635 subd. 4(2)(iv).

also provides additional certainty by allowing the Company to develop multiyear programs of work that are more comprehensive and cost effective, which can deliver cost savings over time through more efficient work planning. When the work is proactive in nature, construction crews can be optimized to reduce mobilization and demobilization costs, coordinate permitting and street construction with impacted communities, and minimize traffic control and rerouting to reduce the overall inconvenience of this work for our customers. Additionally, we can leverage economies of scale by obtaining the requisite project equipment at a competitive price. When work must be completed due to a reactive or emergency driven situation, there is less ability to plan strategically about costs, efficiencies, or community impact.

1. Forecasting

Expenditures for integrity management projects must successfully pass through the Company's capital and O&M budgeting process, which is approved by Company officers and the board of directors. The Company leverages experience with assessments and repairs to assist in developing budgets for future work. Additionally, the Company's gas project management department handles large gas projects and programs. This department provides centralized project management to address overall scope, scheduling, and budgeting for major capital gas projects.

While the Company has strict cost controls in place to ensure that costs are prudently incurred, actual work requirements may cause actual costs to be either higher or lower than initial forecasts. To the extent actual costs are higher, this should not disqualify the additional costs from being considered reasonable, prudent, and eligible for GUIC Rider recovery consideration. The recovery of projects costs, whether in base rates or through a rider, depends on the prudency of those costs rather than the accuracy of an initial forecast. The Commission has previously concluded that "cost overruns can be prudently incurred" and that the "Commission will therefore permit utilities to seek higher recovery levels in future proceedings, with proper documentation and explanation in their rider filings."[32]

Beyond being consistent with longstanding Commission practice and precedent, allowing the Company to true-up GUIC Rider costs if costs differ from initial forecasts is also good policy. Utilities should be encouraged to provide forecasts that are as accurate as possible, given the best information available at the time of the forecast and based on the expertise and judgment of their engineering and project teams. This promotes transparency and predictability when it comes to the costs (and ultimately the rates) associated with these projects. Adopting a bright-line rule with

---

[32] *In the Matter of the Application of ITC Midwest LLC for a Certificate of Need for the Minnesota-Iowa 345 kV Transmission Line Projects in Jackson, Martin, and Faribault Counties*, Docket No. ET-6675/CN-12-1053, at 6 (November 25, 2014).

respect to any costs above a utility's forecast—whether due to permitting delays, weather, or any other factor beyond a utility's control—would distort utility incentives around forecasting accuracy. Specifically, it would create significant incentives for utilities to adopt more conservative approaches to forecasting project costs to avoid disallowances for the sole reason that actual costs exceeded the forecast.

2. *Cost Controls*

The Company's gas business unit monitors capital expenditures to ensure that authorized projects align with the established budget to achieve the lowest reasonable and prudent cost. On a monthly basis, budget to actual spend is compared and financial forecasts are updated for programs and projects.

Integrity management projects follow the Company's sourcing policy, which provides that, with few exceptions, all standard goods and services agreements with a value greater than $50,000[33] are awarded on a documented competitive basis.[34] In the limited circumstances where a competitive process is not required, written justification and director level authorization from the business area and the Company's supply chain department is required.[35]

Furthermore, where practical, the Company establishes bid-unit contracts for activities that are reproducible. Contracts are awarded to the vendors that provide the best overall value, resource availability, and proven safety performance. When bid-unit contracts cannot be used, the Company employs project-specific lump sum bids or written proposals against existing contractual agreements that establish the intended work activities through a written scope of work and confirm the vendor's understanding in their written proposals and schedules.[36]

Aging infrastructure across the country has resulted in many gas operators implementing multi-year replacement programs. This has resulted in heavy competition to secure specialized equipment, engineers, and construction crews required for renewal work. The contractors that complete work as a part of these multi-year replacement programs have been unable to support the total amount of work being done. This has put stress on available engineers, construction contractors, and other needed resources. To that end,

---

[33] Including cumulative amounts in multi-year agreements.
[34] The bid process also ensures compliance with Company policies regarding the use of diverse contractors and suppliers as specified within the Company's corporate policy on supplier diversity.
[35] Some examples of situations where a competitive bid would not be used include emergency work and the absence of competitive firms.
[36] Agreements with a value less than $50,000 are awarded on an informal competitive basis to the extent reasonable to obtain goods and services from a source whose offer is most advantageous to Xcel Energy considering the administrative cost of the purchase.

we have invested not only in robust supply chain procedures, but also in human resources, including engineers and construction crews.

3. *Oversight Methods and Contract/Charge Review*

In addition to using a competitive bid process to secure needed resources, we also employ significant and ongoing cost oversight. The Company conducts a monthly status review of major capital programs and projects, including integrity management projects. We review actual overall capital spending in comparison with forecasted spending monthly and at year-end.

The Company's Rider Review Committee (RRC) reviews projects included in our various rider recovery mechanisms. For the GUIC Rider, the RRC is tasked with ensuring that modifications made to integrity management projects met the intent of the GUIC statute and Company's GUIC Rider. The RRC process is designed to formalize the structure and documentation practices as well as increase the transparency around capital and O&M expenditures related to gas integrity initiatives recovered through rider cost-recovery mechanisms. Program proposals modifying original plans are subject to review, approval, and sign-off based on cost thresholds governed by the RRC's approval matrix guidelines.

In addition to the financial oversight and controls mentioned above, the Company also employs various levels of operational oversight and controls to meet internal standards, and external requirements set forth by the Code of Federal Regulations. All gas projects completed by contractors have assigned inspectors that assist in oversight and validate that the contractor is performing work in accordance with the Company's Pipeline and Compliance Standards Manual. The Company primarily uses contract inspectors for oversight work, as these inspectors can provide specialized experience and equipment. Also, using outside resources for oversight work allows for an independent approach to inspections that is completed in a standard manner consistent with our Pipeline Compliance and Standards Manual.

Other oversight methods include scheduled and unscheduled inspection from members of the Minnesota Office of Pipeline Safety (MNOPS). Each year, MNOPS conducts scheduled field and records inspections throughout our service territory. Additionally, the Company provides MNOPS with information regarding active projects, and inspectors have authority to make unannounced inspections at any time. For example, MNOPS performed 10 planned inspections, 60 unplanned inspections, and evaluated 13 unplanned events through September 2024. Inspections included a review of field locations and records, operations and maintenance procedures, safety-related concerns, and outages.

Integrity management projects have internal personnel identified that oversee the activities. Those personnel work closely with gas engineering, design, and our contractors before, during, and after construction to plan and schedule the work, discuss efficiency opportunities, and communicate challenges that may impact the work as well as its cost. The personnel responsible for oversight also review and approve all project-related invoices to ensure the costs are accurate and reasonable.

As part of our cost review process, all capital and O&M transactions identified as integrity management-related are now individually reviewed monthly and require management approval. We believe this enhanced examination of individual transactions and subsequent validation that each transaction relates to a master service agreement involving Minnesota-specific work and will help prevent instances of inadvertent incorrect jurisdictional assignments moving forward.

4. Outsourcing

While the Company seeks to minimize its outsourcing of TIMP and DIMP work, in certain instances external expertise is needed to help ensure the safe and efficient completion of projects. In these instances, the Company seeks and relies on outside assistance.

The Company uses internal resources when the work falls within the Company's core competencies. External resources are used when the Company has neither the internal expertise nor the equipment available to perform the specialized aspects of a project. By outsourcing the specialized portion of work, the Company saves customers the cost of purchasing expensive, specialized equipment, and ensures investigations are conducted by experienced resources.

When outsourcing is needed, contractor performance is managed through contractor scorecard meetings. Performance is tracked using high-level categories of timeliness, quality and cost specific goals such as:

- Work is completed and invoiced in a timely manner and invoicing is accurate.
- Contractor safety performance is acceptable; damages to existing Company and customer facilities and customer outages are reported accurately and resolved in a timely manner.
- Cost per unit and total spend by work activity are reasonable and explainable, and that the contractors adhere to the contract structure, and identify and explain discrepancies.

The Company's contractual agreements include terms and conditions that address each of the goals listed above. Indeed, the contract covers situations such as work changes, suspension of work, work warranties, and insurance requirements that insulate the Company and its customers from cost overruns due to circumstances within the contractor's control. Once the work is complete, the general conditions specify actions required for final acceptance of the work and price and payment terms. For instance, the Company is not obligated to pay the contractor for work performed incorrectly, work that was beyond the scope of the agreement, or damage caused by the contractor's negligence. These contractual protections serve an important role in protecting against unreasonable and inappropriate cost overruns.

The use of contractors in specialized situations such at this has proven to be cost-effective. It is estimated that by the end of 2025, the Company will have saved almost $16 million using contract work for sewer inspections. This is especially evident as the scope of sewer inspection work has been minimal the past few years and is still planned to be well below where it was before 2019. This work relies on specialized equipment, and the use of contractors prevents the Company incurring sunk costs for purchasing the equipment when the scope of work does not support owning the equipment long-term. A detailed analysis of the savings reaped from contract work in sewer inspections can be found in Attachment I.

C. GUIC Rider Costs are Incremental

The projects for which recovery is being requested in this filing are incremental expenditures not included in either the Company's last natural gas rate case or the pending natural gas rate case. The federal Call to Action leading to the emergence of TIMP and DIMP post-dated the Company's last approved rate case, and the work is uniquely targeted at assessing and improving the safety, reliability, and integrity of our natural gas infrastructure pursuant to state and federal regulatory requirements.

As we have discussed previously, the Commission has agreed that these costs are new and outside of what was requested in our last approved rate case.[37] There have been no foundational changes to TIMP and DIMP that would counsel toward a different result. As such, the Commission should again conclude that the projects that are the subject of this petition were not requested in our previous natural gas rate case, and—in that way—are appropriate for rider recovery.

In addition, all GUIC Rider work completed before December 31, 2021 was rolled into base rates as a part of our most recently approved rate case.[38] The Company filed a new natural gas rate case on November 1, 2023.[39] As a part of that rate case the Company has proposed to roll all GUIC costs incurred between January 1, 2022 and December 31, 2023

[37] *See* ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES, Docket No. G002/M-15-808 (August 18, 2016) at page 6.
[38] Docket No. G002/GR-21-678.
[39] Docket No. G002/GR-23-413.

into base rates at the time final rates are implemented. The costs anticipated to be recovered through the GUIC Rider have not been included in the interim rate request of that filing and are instead showing them in this GUIC Rider request.

The Company has reached a Comprehensive and Unanimous Settlement Agreement with parties in the pending rate case that we anticipate resolving issues.[40] As of the date of this filing, the Commission has not approved the settlement agreement and issued an order in the case. To ensure that no double recovery occurs, after resolution of the pending rate case and this GUIC Rider request, we will adjust our GUIC Rider revenue requirement request to remove any costs rolled into the newly established base rates.

We also note that in previous GUIC Rider filings, we included an adjustment to account for the impact of projects included in our previous base rates that were subsequently replaced as a part of our GUIC work. We are no longer including this adjustment. The most recently approved rate case reset our base rates to 2022, and the pending rate case, if resolved before this request is decided by the Commission would resent our base rates to 2024. As such, the cumulative effect of assets retired due to GUIC work is not yet material enough to factor into our overall request.

Attachment J includes the calculation of our estimate of annual integrity management project-related retirements from 2012 through 2025. In conjunction with the information contained in Table 7 below, Attachment J contains the information required in Minn. Stat. § 216B.1635 subd. 4(iii). Our calculation is primarily based on an analysis of retirement information from 2012 through 2023. For retirements in 2024 and 2025, complete actual data was not yet available.

1. *Internal Capitalized Costs*

While the Company maintains that recovery of internal capitalized costs[41] is appropriately recoverable under the statute as a part of our GUIC Rider requests and the costs are reasonable and necessary for our GUIC work, we understand that the Commission has declined to permit Rider recovery in the past. Since the Commission has denied recovery of these costs in their last several Orders in GUIC dockets, we have removed these costs from this year's proposal. The Company may reassess the inclusion of these costs in future requests.

D. O&M Costs are Specifically Authorized

With this GUIC Rider request, the Company seeks to recover its O&M costs, consistent with the statute and the Commission's approval of this cost treatment in our previous GUIC Rider filings.

---

[40] Filed June 26, 2024 in Docket No. G002/GR-23-413.
[41] Overhead, other, and transportation costs.

The Company provides actual and estimated TIMP and DIMP cost data for 2023 through 2029 in Attachment K. Though we enter our TIMP and DIMP building cycles with a concrete plan of action, ongoing pipeline inspections may result in the reprioritization of projects as we discover risks that may require more immediate intervention. The need for flexibility in planning is critical in pipeline work, and emergent projects can result in fluctuating O&M costs year over year. The Commission has previously recognized this dynamic, noting "[t]he costs of these investments can vary widely from year to year and are difficult to forecast with accuracy. Approving a rider will give Xcel Energy the ability to implement multi-year pipeline-replacement programs, adjusting the rates annually to correct for over- or under-recovery."[42]

E. Estimated Revenue Requirement

Table 7 below presents Xcel Energy's estimated 2025 GUIC Rider revenue requirement of $27.2 million for TIMP, DIMP, and Mandated Relocation activities. Capital-related revenue requirements and O&M expenses total $25.1 million and $2.1 million, respectively.[43]

Table 7
2023-2025 GUIC Rider Revenue Requirement ($ Millions)

	2023 Actuals	2024 Current Forecast	2025 Forecast
Capital-Related Revenue Requirement			
TIMP	$8.83	$2.50	$3.38
DIMP	18.87	11.25	15.00
Mandated Relocations	4.09	6.27	9.42
Total	$31.80	$20.02	$27.80
O&M Expenses			
TIMP	$0.46	$1.04	$0.53
DIMP	0.25	0.41	1.53
Total	$0.70	$1.45	$2.06
Annual Internal Capitalized Costs	($0.70)	($0.70)	($0.70)
MAOP Projects at Long-term Debt Rate of Return	(1.36)	(0.45)	(0.54)
Low-Risk Infrastructure	(0.26)	(0.65)	(1.05)
Prior-year Disallowances	(3.99)	(3.30)	(4.84)
Revenue Requirement Subtotal	$26.19	$16.37	$22.73
True-up Carryover	2.97	4.75	4.46
Total GUIC Rider Revenue Requirement	**$29.16**	**$21.12**	**$27.19**

---

[42] *See* ORDER APPROVING RIDER WITH MODIFICATIONS, Docket No. G002/M-14-336 (January 27, 2015) at page 7.

[43] Numbers in this sentence do not include reductions related to regulatory treatment. Those amounts are shown as separate adjustments in Table 8.

F. Estimated Costs and Salvage Value

Capital expenditure estimates from 2012 through 2029 total about $179 million for TIMP, $452 million for DIMP, and $172 million for mandated relocates, reflecting an estimated total of about $802 million. Distribution mains and services are depreciated using a composite depreciation rate of 2.61 percent, and transmission mains are depreciated using a depreciation rate of 1.69 percent. The Company's depreciation calculations assume an average remaining life of 38.29 years[44] and a net salvage rate of negative 22.85 percent for distribution mains and services and an average remaining life of 59.07 years[45] and net salvage rate of negative 15 percent for transmission mains. The Company's annual cost and salvage estimates related to actual and planned integrity management project capital investments are shown in Table 8 below.

Table 8
GUIC Capital Expenditures and Net Salvage: 2012-2029[46]
($ Thousands)

	TIMP			DIMP[47]	Mandated Relocates	Total
Year	**Transmission**	**Distribution[48]**	**Total**			
2012	$95	$0	$95	$83	$0	$178
2013	65	9,497	9,562	343	0	9,905
2014	(24)	11,651	11,627	240	0	11,867
2015	1,073	17,937	19,010	10,011	0	29,021
2016	4,556	14,196	18,752	13,227	0	31,979
2017	6,191	600	6,791	13,444	0	20,235
2018	8,763	(33)	8,730	36,974	0	45,704
2019	18,603	0	18,603	24,409	0	43,012
2020	28,961	0	28,961	28,441	0	57,402
2021	3,613	0	3,613	51,280	12,915	67,808
2022	3,521	0	3,521	50,557	22,463	76,541
2023	11,772	0	11,772	38,784	20,706	71,263
2024	4,097	0	4,097	27,668	24,386	56,151
2025	17,929	0	14,466	28,199	17,243	63,371
2026	5,840	0	5,840	30,737	18,210	54,787
2027	4,208	0	2,944	31,578	18,145	53,931
2028	2,944	0	2,953	32,234	18,578	53,756
2029	3,012	0	3,012	33,004	19,025	55,041
Total	**124,726**	**53,849**	**178,575**	**451,745**	**171,672**	**801,992**
Salvage Rate[49]	-15.00%	-22.85%		-22.85%	-22.85%	
Net Salvage	**$(18,709)**	**$(12,305)**	**$(31,013)**	**$(103,224)**	**$(39,227)**	**$(173,464)**

[44] Composite average service life for distribution mains and services is 51.76 years.
[45] Average service life for transmission mains is 75 years.
[46] Numbers shown in Table 8 do not include internal labor or RWIP.
[47] Includes approximately $445,000 in software in 2016.
[48] The East Metro Project was originally identified from activities related to TIMP assessment activities; therefore, it is classified under the TIMP category. However, the new plant installed is considered distribution plant from a regulatory accounting perspective.
[49] Depreciation lives and salvage rates approved on July 12, 2022 in Docket No. E,G002/D-22-299. The depreciation lives and salvage rates can be found in Attachment L.

G. Magnitude of GUIC Rider in Relation to the Gas Utility's Approved Base Revenue and Capital Expenditures

The Commission accepted a settlement agreement from all parties in the Company's most recent gas general rate case.[50] The settlement included total related revenue of $806.43 million for the test year ending December 31, 2022. Excluding $5.36 million of other operating income for customer-related charges not included in retail rates and $558.25 million for gas purchase and transportation charges, the total settled base retail revenue was $242.82 million. The revenue collection estimates using the sales information based on a proposed 2025 GUIC Rider rate generates $27.9 million of GUIC Rider-related revenues from March 1, 2026 to February 28, 2027. The GUIC Rider revenue estimates reflect 11.2 percent of the base revenues of $242.82 million included in the accepted rate case settlement for the most recent natural gas rate case.

For more details on the expected 2025 revenues in relation to the last rate case, please reference Attachment M.[51]

VI. GUIC RIDER FACTOR CALCULATIONS, TIMING OF IMPLEMENTATION, TRACKER ACCOUNTING, AND TARIFF SHEET

A. Revenue Requirements and Proposed 2025 GUIC Rider Rate Adjustment Factor

In this section, we provide the 2025 revenue requirement and 2025 rate adjustments factor calculations for the proposed GUIC Rider.

1. Revenue Requirement

The projected 2025 revenue requirement proposed for recovery through the 2025 GUIC Rider adjustment factors from Minnesota gas customers is $27.2 million. The proposed revenue requirement includes recovery of capital property taxes, current and deferred taxes, and book depreciation.

Attachments G and H summarize the projected revenue requirements for the TIMP, DIMP, and mandated relocation projects respectively. The projected GUIC Rider revenue requirements for 2023 through 2029 are summarized in Attachment O to this filing. The supporting revenue requirements and projected 2023 through 2025 GUIC Rider

---

[50] *See* ORDER ACCEPTING AGREEMENT SETTING RATES AND UPDATING BASE COST OF GAS, Docket No. G002/GR-21-678 (April 13, 2023).
[51] Filed in Docket No. E,G999-PR-21-4.

Tracker activity are provided in Attachment P. Attachment Q provides descriptions of the rate base and return calculation categories included in Attachments G and H.

2. Proposed 2023 and 2024 Rates and Carryover Balance

The Company is currently recovering its GUIC Rider revenue requirements based on the rate factors approved in our 2023 GUIC Rider request.[52] For illustrative purposes in this docket, we have assumed that the 2023 carryover balance and 2024 revenue requirements will be recovered from March 2025 through February 2026. The presumed rate factors are shown in Table 10 below.

3. GUIC Rider Rate Adjustment Factors

The Company's GUIC Rider adjustment factor rate design currently provides for rates specific to four customer groups (residential, commercial firm, commercial demand billed, and interruptible). The revenue requirement is allocated to classes in the same manner as revenues were apportioned in our most recently approved natural gas rate case.[53] Consistent with most recent approved GUIC Rider request, the Company is using an apportionment that combines transportation customers with their respective firm or interruptible sales classes. This aligns with our rate design goal to remain indifferent to a customer's choice of sales or transportation service. Table 9 below provides the current revenue apportionment.

Table 9
Current Revenue Apportionment

Class	Current Allocator
Residential	64.1618%
Commercial	24.1303%
Demand (including Firm Transport)	6.6297%
Interruptible (including Interruptible Transport)	5.0782%
Total	**100%**

Proposed class factors are calculated by dividing the class revenue responsibility by the 12 months of weather-normalized actual sales data. The GUIC Rider adjustment factor is included in the Resource Adjustment line on customer bills. Consistent with our 2024 GUIC Rider filing, we are using actual sales data in our 2025 GUIC factor calculation for this request.

---

[52] *See* ORDER, Docket No. G002/M-22-578 (May 30, 2023)
[53] Docket No. G002/GR-21-678.

The 2024 and 2025 GUIC Rider adjustment factor calculations are shown in Attachment R. Table 10 below shows the currently approved 2023 and 2024 GUIC Rider adjustment factors and proposed 2025.

Table 10
Proposed GUIC Rider Adjustment Factors (Dollars per therm)

Classes	Current Factors	2024 Approved Factors[54]	2025 Proposed Factors[55]
Residential	$0.040548	$0.027955	$0.045267
Commercial Firm	$0.025059	$0.016760	$0.027222
Demand	$0.005090	$0.002401	$0.003815
Interruptible	$0.009463	$0.006854	$0.013254

The residential bill impacts under each factor are shown in Table 11 below.

Table 11
Monthly Residential Bill Impacts

	Impact of Current Factors	Impact of 2025 Proposed Factors
Monthly Bill Impact	$3.58	$3.21
Incremental Bill Impact Change as % of Total Bill		-.061%

B. Timing of 2025 GUIC Rider Factor Implementation

We request approval to implement GUIC Rider factors in this annual report, effective March 1, 2026, pending review and approval by the Commission. The factor calculations shown above assume that the 2025 GUIC Rider costs will be recovered during this timeframe. Our proposed timing for 2025 GUIC Rider recovery is consistent with the timing of recovery approved in our 2024 GUIC Rider filing, which follows the approved timing of recovery approved in our 2023 GUIC Rider filing. Starting recovery on March 1, 2026 has the added benefit of eliminating the need to prorate our ADIT calculation, as recovery will not start until after the end of the cost period. In addition, the proposed timing will allow us to collect 12 months of GUIC Rider costs over 12 months of bills, which allows for more stable factors.

---

[54] Approved by Commission in Docket No. G002/M-23-457 via consent agenda on September 17, 2024. Assumes recovery from March 1, 2025 through February 28, 2026.
[55] Assumes the 2025 GUIC Rider revenue requirement is recovered March 1, 2026 through February 28, 2027.

The Company believes this approach is beneficial as it is consistent with the Legislature's intent to provide timely cost recovery to support the significant and mandated natural gas infrastructure investments. It also maintains appropriate regulatory protections and oversight by allowing the Commission and other state agencies the time required to audit and review costs sought for recovery, thus ensuring that any regulatory adjustments will be recognized and implemented appropriately.

C. GUIC Rider Tracker Account

To ensure that customers are not under or overcharged, we record the actual GUIC Rider revenue recovery and requirements in a tracker account as the accounting mechanism for eligible integrity management project costs. As revenues are collected from retail customers each month, the Company tracks the amount of recovery under the GUIC Rider rate factor and compares that amount with the monthly revenue requirements.

The difference is recorded in the tracker account as the amount of over- or under-recovery. Differences in revenue requirements from forecast to actual amounts are also recorded in the tracker. Any over- or under-recovery balance at the end of the year is used in the calculation of the rate factor for the next year's forecasted revenue requirement. In other words, over-recovery is considered by reducing the subsequent year's rate factor calculation. Under-recovery is similarly considered by increasing the subsequent year's rate factor calculation. The revenue requirements included in the tracker are only those related to Minnesota's jurisdictional share of eligible integrity management projects.

We calculate the monthly Minnesota jurisdictional revenue requirements (including appropriate overall return, income taxes, property taxes, and depreciation), compare them with monthly GUIC Rider recoveries from customers, and place the under-recovered amounts in FERC Account 182.3, Other Regulatory Assets and over-recovered amounts in FERC Account 254, Other Regulatory Liabilities (the Tracker Accounts). Tracker balances for GUIC Rider activity estimated in 2024 are shown on Attachment R within the carryover rollforward section. Attachment S includes a tracker that presents revenue requirement, rates, and recoveries within the same page to provide a clearer understanding of how the GUIC revenue requirement is recovered via the rider.

D. Proposed Tariff Sheet and Customer Notice

1. Proposed Revised Tariff Sheet

The proposed 2025 GUIC Rider factors can be found in the clean and redline formats of Tariff Sheet No. 5-64 provided in Attachment T.

2. *Proposed Customer Notice*

We will provide notice to customers regarding inclusion of this cost on their monthly bill. The following is our proposed language to be included as a notice on customers' bills the month the GUIC Rider factor is implemented:

> This month's Resource Adjustment includes an updated Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is $x.xxxx per therm for Residential customers; $x.xxxx per therm for Commercial Firm customers; $x.xxxx per therm for Commercial Demand Billed customers; and $x.xxxx per therm for Interruptible customers.

We will work with the Department and Commission staff if there are any suggestions to modify this notice.

VII. RATE OF RETURN

The GUIC statute states that "[t]he return on investment for the rate adjustments shall be at the level approved by the commission in the public utility's last general rate case, unless the commission determines that a different rate of return is in the public interest."

For our 2025 GUIC Rider request, the Company is using the return on equity, capital structure, and rate of return agreed to in the unanimous settlement and approved by the Commission in our prior natural gas rate case for recovery purposes in this GUIC Rider request. In the settlement, parties agreed to a return of equity of 9.57 percent, a cost of short-term debt of 0.94 percent, and a cost of long-term debt of 4.13 percent.[56] When paired with the settled-upon capital structure from the rate case, we propose using an overall rate of return of 6.97 percent for this request. Table 12 below shows the capital structure ratios and costs proposed in the rate case and the calculation of the overall rate of return.

---

[56] ORDER ACCEPTING AGREEMENT SETTING RATES AND UPDATING BASE COST OF GAS, Docket No. G002/GR-21-678.

Table 12
Recommend Capital Structure, Costs, and Rate of Return

	Percent of Total Capital	Cost	Weighted Cost
Short-Term Debt	0.61%	0.94%	0.01%
Long-Term Debt	46.89%	4.13%	1.94%
Common Equity	52.50%	9.57%	5.02%
Total	100.00%		6.97%

We understand that we have a settlement agreement in front of the Commission in our currently pending natural gas rate case. We are not proposing using the capital structure, costs, and rate of return from that pending rate case in this request as it has not yet been approved by the Commission. If it is approved by the Commission, we will modify the request to use the approved rate of return factors.

VIII. GUIC RIDER PERFORMANCE METRICS

The development of performance metrics has been an ongoing effort since our 2016 GUIC Rider filing. This effort started at the behest of the Commission. In its August 18, 2016 Order,[57] the Commission requested that:

> *The Company develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC filings, and provide stakeholders the opportunity for meaningful involvement.*

The Commission also instructed that:

> *Each metric should include a reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.*

Through several discussions with stakeholders the Company developed a set of metrics that were ultimately approved by the Commission. These metrics have been refined over time as additional review has taken place. Table 13 below shows the TIMP and DIMP performance metrics most recently approved by the Commission.[58] Attachment

---

[57] ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES, Docket No. G002/M-15-808.
[58] Docket No. G002/M-22-578.

U further discusses this set of the metrics to measure the appropriateness of GUIC expenditures.[59]

Table 13
Performance Metrics

Program	Project	Cost Performance Metric	Effectiveness Performance Metric
TIMP	Transmission Pipeline Integrity Assessments	Estimated versus actual costs per project	Anomalies repaired by type
	ASVs and RCVs	Estimated versus actual costs per project	Reduction in response time per project
	Programmatic Replacement and MAOP Remediation	Estimated versus actual costs per project	Percentage of high/medium risk projects system-wide
DIMP	Poor Performing Main Replacement	Poor performing main replacement unit cost (per foot)	Leak rate by vintage
	Poor Performing Service Replacement	Poor performing service replacement unit cost (per foot)	Leak rate by vintage
	Distribution Pipeline Integrity Assessment	Estimated versus actual costs per project	Anomalies repaired by type
	Distribution Valve Replacement	Estimated versus actual costs per project	Percentage of inoperable valves replaced
	Distribution Valve Replacement (New Valves Only)	Estimated versus actual costs per project	Reduction in potential customer outages
	Sewer and Gas Line Conflict Remediation	Inspection Unit Cost	Percentage of Total Premises Inspected
TIMP/DIMP	Casing Renewals	Estimated versus actual costs per project	Percentage of casing projects planned for the year completed Total number completed compared to Total number requiring remediation, since inception
	Mandated Relocations	Estimated versus actual costs per project	Number of planned mandated relocations versus actual relocations

[59] Please note we are not including performance metrics information for ASVs and RCVs as there is no completed or planned activity for that program from 2023 through 2029.

IX. RATE CASE SETTLEMENT COMPLIANCE INFORMATION

The following information is provided in Compliance with the settlement agreement approved in Docket No. G002/GR-21-678.

A. DIMP Multi-year Project Estimates

The information provided in Table 14 below depicts the current estimated DIMP costs for five years, broken out by capital and O&M expenditures. It is important to note that in many cases the figures presented are high-level estimates.

Table 14
Forecasted DIMP Costs
($ in Millions)

	2025 Estimates		2026 Estimates		2027 Estimates		2028 Estimates		2029 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Poor Performing Mains	$19.5	$0.00	$20.05	$0.00	$20.6	$0.00	$21.0	$0.00	$21.5	$0.00
Poor Performing Services	$6.50	$0.53	$6.68	$0.57	$6.87	$0.64	$7.00	$0.71	$7.17	$0.78
IP Line Assessments	$0.00	$0.28	$0.00	$0.32	$0.00	$0.25	$0.00	$0.26	$0.00	$0.27
Sewer and Gas Line Conflict Investigation	$0.00	$1.25	$0.00	$1.30	$0.00	$1.35	$0.00	$1.41	$0.00	$1.47
Distribution Valve Replacements	$0.47	$0.00	$0.61	$0.00	$0.62	$0.00	$0.64	$0.00	$0.65	$0.00
Casing Renewals	$3.20	$0.00	$5.00	$0.00	$5.12	$0.00	$5.24	$0.00	$5.37	$0.00

Poor Performing Mains and Services: Under 49 CFR Part 192.1007(d), the Company must determine and implement measures designed to reduce the risks from failures of its gas distribution pipeline. As a result, the Company uses subject matter expertise, historical leak data, and industry information to identify risk factors that may lead to gas pipeline leaks or failures. The annual replacement levels of high- and medium-risk pipe and services are based on these factors. Additionally, IP line inspections and replacements are part of an ongoing program that involves the regular inspection and replacement of high- and medium-risk segments of pipeline to satisfy the federal pipeline safety regulations set forth by PHMSA rules.[60]

Distribution Valve Replacement: This work is in response to the Company's obligation under Code 49 CFR Part 192.1007(d). In addition to new valve installations, the program will replace existing distribution system isolation valves which have become inaccessible, inoperable or are beyond their useful life.

Casing Renewal: As with the transmission casing renewal project, this work is being done in accordance with the Company's Gas Standards Manual section 9.9.9 and 49 CFR § 192.467. Under this project, the Company isolates pipes and casings that are determined to be in contact with one another (or unable to take readings), mitigates leakage risk for sites that indicate the presence of corrosion or where testing has not occurred, and replaces pipe where it is not possible to test or isolate the pipe. Metallic pipes need to remain isolated from each other to reduce corrosion risk.

B. TIMP Multi-year Project Estimates

The information provided in Table 15 below depicts the current estimated TIMP costs for five years, broken out by capital and O&M expenditures. It is important to note that in many cases the figures presented are high-level estimates.

Table 15
Forecasted TIMP Costs
($ in Millions)

	2025 Estimates		2026 Estimates		2027 Estimates		2028 Estimates		2029 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Transmission Pipeline Assessments	$0.94	$0.55	$1.15	$0.73	$1.82	$0.60	$0.38	$0.80	$0.39	$0.82
Transmission Pipeline Assessment Sleeve Repair	$0.10	$0.00	$0.10	$0.00	$0.10	$0.00	$0.19	$0.00	$0.19	$0.00
Programmatic Replacement / MAOP Remediation	$3.88	$0.00	$2.57	$0.00	$2.57	$0.00	$2.57	$0.00	$2.63	$0.00
Transmission Rule	$0.00	$0.05	$0.00	$0.05	$0.00	$0.06	$0.00	$0.06	$0.00	$0.06
Casing Renewal	$11.1	$0.00	$1.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

[60] *See* 49 CFR Part 192.921 (a). The rule requires an operator to assess the integrity of the line pipe in each covered segment by applying one or more of the approved methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment.

Transmission Pipeline Assessments: This project is an ongoing program, beginning in 2002, of health and condition assessments on gas transmission lines. Federal regulations require assessment of gas transmission pipelines using ILI, pressure testing or direct assessment.[61] Regular assessment of pipelines is based on the health and condition of the assets as well as an evaluation of the risks and threats. The Company's objective is to monitor anomalies found on the pipelines, assess if they are stable or deteriorating, and mitigate the anomaly before it becomes a threat to public safety.

Programmatic Replacement/MAOP Remediation: The MAOP Remediation Advisory Bulletin[62] issued by PHMSA in 2012, and MAOP Reconfirmation requirements contained in CFR § 192.624, specifically address pipeline safety in terms of verification of maximum allowable operating pressure records. Federal code requires operators to reconfirm the MAOP of all applicable pipeline segments, and ensure the MAOP is supported by traceable, verifiable, and complete records. The MAOP initiative focuses on obtaining adequate proof of MAOP records and ensuring that they become part of the Company's official system of record. Remediation of data gaps is also part of the scope. The cost estimates for this program are based on our experience with similar assets in prior years. Actual results from assessments will drive the overall scope and timing of these capital expenditures.

Casing Renewal: This project is like the shorted casing – Distribution Project. As an integrated part of the Company's DIMP plan, similar needs have been identified as part of TIMP for Transmission pipelines, which is a principal requirement of managing risk under integrity management programs. Metallic pipes need to remain isolated from each other to reduce corrosion risk. This project started in the 2021 construction season and shall continue annually until all casings risks on the program list have been mitigated.

C. Suggestion of Delay or Cancel Expected Projects

As the above-mentioned programs/projects have been identified as being of High- or Medium-risk or are required to comply with federal and state pipeline safety laws and regulations, the Company believes it is not reasonable nor prudent to not proceed with the planned work in support of system safety and integrity. This is consistent with safety and system integrity benefits that have been generated by our DIMP and TIMP work.

---

[61] The requirements are further defined in the Company's TIMP manual.
[62] ADB-12-06, Docket No. PHMSA-2012-0068.

CONCLUSION

The Company implemented transmission and distribution integrity management plans to be able to follow evolving federal and state regulatory standards. Our TIMP and DIMP plans are prudent investments that have resulted in the replacement of aging pipelines. By completing these replacements, the Company has minimized public safety risks associated with aging assets that deliver gas service.

The legislature authorized the prompt recovery of integrity management costs in 2013, and the Commission validated the importance of that prompt recovery in their previous GUIC Rider Orders. In this filing, the Company provides updates on the status of our TIMP and DIMP activities by describing the safety and reliability the Company brings to our gas system with the planned work. We further highlight our plan to recover the remaining 2024 investment that has not yet been recovered and outline our proposal to recover the 2025 investments. Xcel Energy respectfully requests that the Commission, consistent with its previous GUIC Rider Orders, grant recovery of gas utility infrastructure costs through the GUIC Rider and approve the proposed 2025 GUIC Rider factors.

Dated: October 31, 2024

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF A GAS UTILITY INFRASTRUCTURE COST RIDER TRUE-UP REPORT FOR 2023, UPDATED COSTS FOR 2024, REVENUE REQUIREMENTS FOR 2025, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. G002/M-24-___

PETITION, COMPLIANCE FILING, AND ANNUAL REPORT

SUMMARY OF FILING

Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), submits this Petition, Compliance Filing, and Annual Report to the Minnesota Public Utilities Commission. To promote a safe and reliable gas system, Xcel Energy has undertaken approved threat evaluation, assessment, and risk mitigation activities, in compliance with federal regulations. We request approval to recover gas utility infrastructure costs (GUIC) through the GUIC Rider. Xcel Energy requests cost recovery of its projected 2025 Transmission and Distribution Integrity Management Programs costs pursuant to Minn. Stat. § 216B.1635, which permits a utility to petition the Commission for recovery. The Company also seeks approval of its 2025 GUIC Rider adjustment factors and its proposed capital structure and ROE for 2025.

Compliance Matrix

Petition Requirements	Reference
Minnesota Statute § 216B.1635	
Subd. 2. **Gas infrastructure filing.** A public utility submitting a Petition to recover gas infrastructure costs under this section must submit to the commission, the department, and interested parties a gas infrastructure project plan report and a Petition for rate recovery of only incremental costs associated with projects under subdivision 1, paragraph (c). The report and Petition must be made at least 150 days in advance of implementation of the rate schedule, provided that the rate schedule will not be implemented until the Petition is approved by the commission pursuant to subdivision 5. The report must be for a forecast period of one year.	The filing date of this Petition, October 31, 2024, is 486 days before our proposed implementation date of March 1, 2026. We discuss the proposed implementation date in Section VI.B. of our Petition. The report is for a one-year forecast period from January 1, 2025 through December 2025.
Subd. 3. **Gas infrastructure project plan report.** The gas infrastructure project plan report required to be filed under subdivision 2 shall include all pertinent information and supporting data on each proposed project including, but not limited to, project description and scope, estimated project costs, and project in-service date.	Details on each TIMP project can be found in Attachments C and C1. Details on each DIMP project can be found in Attachments D and D1. Details on the Mandated Relocation projects can be found in Attachments D and E.
Subd. 4. **Cost recovery Petition for utility's facilities.** Notwithstanding any other provision of this chapter, the commission may approve a rate schedule for the automatic annual adjustment of charges for gas utility infrastructure costs net of revenues under this section, including a rate of return, income taxes on the rate of return, incremental property taxes, incremental depreciation expense, and any incremental operation and maintenance costs. A gas utility's Petition for approval of a rate schedule to recover gas utility infrastructure costs outside of a general rate case under section 216B.16 is subject to the following: (1) a gas utility may submit a filing under this section no more than once per year; and (2) a gas utility must file sufficient information to satisfy the commission regarding the proposed GUIC. The information includes, but is not limited to:	The filing date of this Petition is October 31, 2024. Our 2024 GUIC Rider Petition was filed on October 23, 2023.

Compliance Matrix

Petition Requirements	Reference
(i) the information required to be included in the gas infrastructure project plan report under subdivision 3;	Details on each TIMP project can be found in Attachments C and C1. Details on each DIMP project can be found in Attachments D and D1. Details on the Mandated Relocation projects can be found in Attachments D and E.
(ii) the government entity ordering or requiring the gas utility project and the purpose for which the project is undertaken;	The government entity ordering each project and purpose for each TIMP project can be found in Attachment C1. The same information can be found for each DIMP project in Attachment D1 and the Mandated Relocation projects in Attachment E.
(iii) a description of the estimated costs and salvage value, if any, associated with the existing infrastructure replaced or modified as a result of the project;	A description and quantification of the assets retired because of GUIC work is included in Attachment J. The estimated salvage value of our GUIC projects is shown in Table 8 in Section V.F. of our Petition.
(iv) a comparison of the utility's estimated costs included in the gas infrastructure project plan and the actual costs incurred, including a description of the utility's efforts to ensure the costs of the facilities are reasonable and prudently incurred;	Actual and estimated cost information and a discussion of the reasonableness and prudence of our TIMP projects can be found in Attachment C. The same information can be found for our DIMP projects in Attachment D.
(v) calculations to establish that the rate adjustment is consistent with the terms of the rate schedule, including the proposed rate design and an explanation of why the proposed rate design is in the public interest;	The public interest support for our request is found in Section V.A. of our Petition. The revenue requirements and proposed GUIC Rider Rate Adjustment Factors are discussed in Section VI.A of our Petition. Details of our revenue requirement request can be found in Attachments F,G,H,K,O,P,Q,R.

Compliance Matrix

Petition Requirements	Reference
(vi) the magnitude and timing of any known future gas utility projects that the utility may seek to recover under this section;	Details of the magnitude and timing of known future TIMP projects through 2025 can be found in Attachment C1. A higher-level summary of the magnitude and timing of costs through 2029, by program, can be found in Attachments C and Attachment F. Details of the magnitude and timing of our DIMP projects can be found in Attachment D1, and higher-level information of magnitude and timing can be found in Attachments D and Attachment F. Details of the magnitude and timing of our Mandated Relocation projects can be found in Attachments D and E, and higher-level information of magnitude and timing can be found in Attachment F.
(vii) the magnitude of GUIC in relation to the gas utility's base revenue as approved by the commission in the gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges; (viii) the magnitude of GUIC in relation to the gas utility's capital expenditures since its most recent general rate case; and	A comparison of our requested GUIC Rider recovery in relation to the base revenues and capital expenditures agreed to in the Company's most recent natural gas rate case settlement is shown in Section V.G. of our Petition and Attachment M.

Compliance Matrix

Petition Requirements	Reference
(ix) the amount of time since the utility last filed a general rate case and the utility's reasons for seeking recovery outside of a general rate case.	The Company last filed a general rate case in 2023. The Company reached a Comprehensive and Unanimous Settlement Agreement with parties. The Settlement Agreement is pending Commission action. The Settlement Agreement included a 2024 test year. We discuss our reasons for seeking recovery through the GUIC Rider mechanism in Sections I, V.A., V.B., and V.D. of our Petition.
Subd. 6. **Rate of return.** The return on investment for the rate adjustment shall be at the level approved by the commission in the public utility's last general rate case, unless the commission determines that a different rate of return is in the public interest.	We are requesting to use the rate of return included in the approved settlement from our most recent natural gas rate case. We discuss this in Section VII of our Petition.
In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider (GUIC) True-up Report for 2015, Forecasted 2016 GUIC Revenue Requirement, and Revised GUIC Adjustment Factors **Minnesota Public Utilities Commission** ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES **August 18, 2016 Docket No. G002/M-15-808**	
2. Xcel shall develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC Rider filings, and provide stakeholders the opportunity for meaningful involvement. Each metric should include reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.	We provide a discussion of performance metrics in Section VIII of our Petition. The Commission approved the set of metrics on May 5, 2023 in Docket No. G002/M-21-765. The results of the performance metrics are provided in Attachment U.

Compliance Matrix

Petition Requirements	Reference
8. Xcel shall modify the proposed customer notice to read: This month's Resource Adjustment includes ~~the addition of the~~ an updated Gas Utility Infrastructure Cost Adjustment (GUIC), which recovers the costs of assessments, modifications and replacement of natural gas facilities as required by state and federal safety programs. The GUIC portion of the Resource Adjustment is $x.xxxx per therm for Residential customers; $x.xxxx per therm for Commercial Firm customers; $x.xxxx per therm for Commercial Demand Billed customers; and $x.xxxx per therm for Interruptible customers. Questions? Contact us at 1-800-895-4999.	The proposed customer notice for our 2025 request reflects this language. We show the proposed customer notice in Section VI.D.2 of our Petition.
In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider (GUIC) True-up Report for 2016, Forecasted 2017 GUIC Revenue Requirement, and Revised GUIC Adjustment Factors **Minnesota Public Utilities Commission** ORDER APPROVING RIDER RECOVERY WITH MODIFICATIONS **February 8, 2018 Docket No. G002/M-16-891**	
6. Xcel shall continue to provide, in future GUIC filings, specific information about each individual project in the GUIC rider that sufficiently (1) describes what the project is, (2) explains why the project is necessary, (3) discusses what benefits ratepayers will receive from the project, and (4) identifies the agency, regulation, or order that requires the project.	A discussion of each TIMP program is provided in Section II of our Petition, with details of each project in Attachments C and C1. A discussion of each DIMP program is provided in Section III of our Petition, with details of each project in Attachment D and D1. A discussion of our Mandated Relocation program is provided in Section IV of our Petition, with details of each project in Attachments D and E.
8. The Commission approves a revised sales forecast based on the Company's regression model results before monthly sales and demand-side management (DSM) adjustments as set forth by the Company in Attachment F of its reply comments for the 2017 GUIC rider.	Not applicable for this filing. 12 months of weather-normalized actual sales data were used to calculate proposed rate factors.

Compliance Matrix

Petition Requirements	Reference
10. Xcel shall provide a cost/benefit analysis in its initial Petition in future GUIC rider filings if the Company wishes to receive accelerated recovery of sewer lines costs on a going forward basis.	The use of contract work for the completion of sewer inspection work is discussed in Section V.B.4. An analysis of the cost of using contract work versus in-house resources is included in Attachment I.
In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider True-up Report for 2017, the Forecasted 2018 Revenue Requirements, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER APPROVING RIDER RECOVERY WITH MODIFICATIONS **August 12, 2019 Docket No. G002/M-17-787**	
16. In all future GUIC rider Petitions, Xcel must include the reporting required by Minn. Stat. § 216B.1635, subd. 4(2)(iii).	A description and quantification of the assets retired because of GUIC work are included in Attachment J. The estimated salvage value of our GUIC projects is shown in Table 8 in Section V.F of our Petition.
17. In all future GUIC rider Petitions, Xcel must include only incremental rate base amounts in its GUIC rider rate base.	The costs removed from our GUIC Rider request to ensure that only incremental costs are included are discuss in Section V.C of our Petition. The costs removed are for internal capital costs, such as overheads and other costs.
18. Xcel must include, prior to applying its calculated property tax rate, only the incremental property tax expense amount for all GUIC years by adjusting the original cost of GUIC projects by the original cost of plant assets replaced by (or retired through) the GUIC projects in each year.	With base rates being reset to 2022 in our most recent rate case (and potentially to 2024 in our pending rate case), this adjustment is not currently material enough to include. We will reassess this adjustment in the future.

Compliance Matrix

Petition Requirements	Reference
22. In all future GUIC filings, Xcel must include historical and projected GUIC revenue requirements, rates, and recoveries within a single tracker for each year.	This information is shown in Attachment R.
In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of a Gas Utility Infrastructure Cost Rider True-Up Report for 2018, the Forecasted 2019 Revenue Requirements, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS **January 9, 2020 Docket No. G002/M-18-692**	
3. Xcel shall not apply prorated accumulated deferred income tax (ADIT) to rate base when it is not required by the Internal Revenue Service for normalization purposes.	As our requested recovery period begins after the end of our requested test year, there is no need to prorate ADIT. This issue is discussed in Petition Section VI.B.
5. Xcel shall use the most recent 12 months of actual natural gas sales to calculate the final GUIC rate.	12 months of weather-normalized actual sales data were used to calculate proposed rate factors. This is noted in Section VI.A.3 of the Petition. Sales forecast amounts are shown in Attachment R.
6. The Commission denies Xcel's request for a carrying charge in the GUIC tracker account.	Request does not include carrying charge.
7. Xcel shall remove and exclude from the GUIC rider costs related to low-risk infrastructure replacement that is not mandated by government regulations or public work requirements.	We removed all known low-risk infrastructure work from the 2018 through 2025 revenue requirements.

Compliance Matrix

Petition Requirements	Reference
8. The return on the capital costs incurred to remediate the system's MAOP data gaps shall be limited to Xcel's weighted long-term cost of debt.	Our request includes an adjustment to limit the return on 2018 through 2025 capital costs for the MAOP program to the Company's weighted long-term cost of debt. The adjustment is reflected in the 2018 through 2025 regulatory treatment adjustments in Attachments O and P.
9. Xcel shall remove the costs of Overhead, Transportation, and Other, totaling $8,157,695, from the GUIC rider.	Our request includes adjustments to remove the costs from revenue requirement calculations for 2025. The adjustments reflect the amount of overheads, transportation, and other costs removed from 2018 through 2025 GUIC projects. The adjustment is reflected in the 2023 through 2025 regulatory treatment adjustments in Attachments O and P. We discussed this in Section V.C.1 of our Petition.
11. Xcel shall exclude from its 2019 and future GUIC rider revenue requirements all costs related to emergency sewer-conflict work. Accordingly, Xcel shall adjust its 2019 GUIC rider revenue requirement to remove (1) $50,000 for these costs applicable to 2019, and (2) $371,364 for costs that were erroneously included in the rider in previous years.	An adjustment was previously included for our 2019 revenue requirement to reflect the removal of emergency sewer-conflict work. No adjustment is currently necessary, as no emergency sewer work is included in our 2020 through 2025 requests.
14. Xcel shall continue to improve its risk assessment reporting in future GUIC filings, with the goal of providing better explanations of the Company's assets.	We discuss our continued improvement process for risk assessments in Section V.A.3 of the Petition.

Compliance Matrix

Petition Requirements	Reference
15. Xcel shall provide consequence class information for both plastic and steel mains and services in future GUIC filings.	Consequence class information for mains and services is included in Attachments C, C2, D, and D2 and is discussed in Section V.A.3 of the Petition.
16. Xcel shall develop full risk-assessment profiles for the TIMP Transmission Pipeline Assessment program and the TIMP Programmatic/MAOP Remediation program.	Full risk-assessments profiles are included for the TIMP programs. Issue is discussed in Section V.A.3 of our Petition and information is shown in Attachments C and C2.
18. The Department and Xcel shall continue efforts to reach a consensus on establishing performance metrics in future GUIC Petitions.	We provide a discussion of performance metrics in Section VIII of our Petition. The Commission approved the set of metrics on May 5, 2023 in Docket No. G002/M-21-765. The results of the performance metrics are provided in Attachment U.
In the Matter of the Petition of Northern States Power Company for Approval of a Gas Utility Infrastructure Cost Rider True-Up Report for 2019, Revenue Requirements for 2020, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS **May 3, 2021 Docket No. G002/M-19-664**	
3. Xcel Energy shall use the most recent 12 months of actual natural gas sales to calculate the final GUIC rate.	12 months of weather-normalized actual sales data were used to calculate proposed rate factors. This is noted in Section VI.A.3 of the Petition. Sales forecast amounts are shown in Attachment R.

Compliance Matrix

Petition Requirements	Reference
4. The "return on" the capital costs incurred to remediate the system's MAOP data gaps shall be limited to Xcel Energy's weighted long-term cost of debt over the life of these capital expenditures.	Our request includes an adjustment to limit the return on 2018 through 2025 capital costs for the MAOP program to the Company's weighted long-term cost of debt. The adjustment is reflected in the 2018 through 2025 regulatory treatment adjustments in Attachments O and P.
5. The Company's proposed recovery of GUIC internal capital costs for Overheads, Other, and Transportation is denied, to the extent these costs are not removed elsewhere.	Our request includes adjustments to remove the costs from revenue requirement calculations for 2025. The adjustments reflect the amount of overheads, transportation, and other costs removed from 2018 through 2025 GUIC projects. The adjustment is reflected in the 2023 through 2025 regulatory treatment adjustments in Attachments O and P. We discussed this in Section V.C.1 of our Petition.
In the Matter of Northern States Power Company, for Approval of a Gas Utility Infrastructure Cost Rider True-Up Report for 2020, Revenue Requirements for 2021, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER **November 18, 2022 Docket No. G002/M-20-799**	
5. Required Xcel Energy to continue to assign revenue responsibilities of project costs based on the apportionment established in the Company's most recent rate case.	Apportionment of costs is discussed in Section VI.A.3 of our Petition.

Compliance Matrix

Petition Requirements	Reference
6. Required Xcel Energy to use the most recent 12 months of actual natural gas sales to allocate the costs across jurisdictions and classes.	12 months of weather-normalized actual sales data were used to calculate proposed rate factors. This is noted in Section VI.A.3 of the Petition. Sales forecast amounts are shown in Attachment R.
In the Matter of the Application of Northern States Power Company d/b/a/Xcel Energy for Authority to Increase Natural Gas Rates in Minnesota **Minnesota Public Utilities Commission** ORDER ACCEPTING AGREEMENT SETTING RATES AND UPDATING BASE COST OF GAS **April 13, 2023 Docket No. G002/GR-21-678**	
Settlement Agreement, Section III, Part F (October 4, 2022) For purposes of Settlement, the Settling Parties agree that within 30 days of the Docket No. G002/GR-21-678 Commission's final order in this proceeding, the Company will provide a compliance filing including (1) an estimate of its TIMP and DIMP costs for the next five years, and (2) a narrative of the types of projects included in the cost estimates and the extent to which it would be possible to delay or cancel the expected projects while continuing (a) compliance with federal and state pipeline safety laws and regulations and (b) identification and replacement of High and Medium risk infrastructure to reduce risk and maintain appropriate levels of work to support system safety and integrity. Beginning in 2023 (i.e., with the 2024 GUIC filing), the Company will also provide subparts (1) and (2) of this paragraph in its annual GUIC petition (as opposed to in the attachments to the GUIC petition).	This required information is provided in Section IX of the Petition.

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Company, for Approval of a Gas Utility Infrastructure Cost Rider True-Up Report for 2020, Updated Costs for 2021, Revenue Requirements for 2022, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS **May 5, 2023 Docket No. G002/M-21-765**	
5. Xcel Energy shall continue to assign revenue responsibilities for GUIC Rider costs based on the apportionment established in Docket No. G-002/GR-09-1153, *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Gas Service in Minnesota*.	Apportionment of costs are discussed in Section VI.A.3 of our Petition.
6. The Commission approves Xcel Energy's request to use the most recent 12 months of Actual natural gas sales to allocate the costs across jurisdictions and classes.	12 months of weather-normalized actual sales data were used to calculate proposed rate factors. This is noted in Section VI.A.3 of the Petition. Sales forecast amounts are shown in Attachment R.
9. The Commission approves Xcel Energy's Performance Metrics.	We provide a discussion of performance metrics in Section VII of our Petition. The Commission approved the set of metrics on May 5, 2023 in Docket No. G002/M-21-765. The results of the performance metrics are provided in Attachment U.

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Company, for Approval of a Gas Utility Infrastructure Cost Rider True-Up Report for 2021, Updated Costs for 2022, Revenue Requirements for 2023, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER **May 30, 2023 Docket No. G002/M-22-578**	
2. Ordered Xcel to adjust its GUIC revenue requirement to account for cancelled Projects.	The 2023 revenue requirement request does not include cancelled projects, and the 2024 revenue requirement only includes projects we expect to complete in 2024.
4. Ordered Xcel to report all reimbursements as offsets to total revenue requirements in future true-up filings.	The actual amount of reimbursements received for mandated relocation projects is shown in Attachment D. Please note that capital expenditures shown in Attachment D and the plant in-service and capital expenditures shown in other parts of this report are shown net of reimbursements, and our revenue requirement is calculated net of reimbursements. As such no additional adjustments are needed for reimbursements.

Compliance Matrix

Petition Requirements	Reference
In the Matter of the Petition of Northern States Power Co., d/b/a Xcel Energy for Approval of Gas Utilities Infrastructure Cost Rider True-Up Report for 2022, Updated Costs for 2023, Revenue Requirements for 2024, and Revised Adjustment Factors **Minnesota Public Utilities Commission** ORDER (via Consent Calendar) **September 17, 2024 Docket No. G002/M-23-457**	
2. Required Xcel Energy to provide true-up information for 2023 and 2024 in the next GUIC rider filing	Updates to TIMP, DIMP, and Mandated Relocation costs for 2023 and 2024 are shown in Attachments C and D. Attachments O and M show details of the updated revenue requirement information for 2023 and 2024.
3. Required Xcel Energy to report reimbursements as adjustments/offsets in future true-up filings	The actual amount of reimbursements received for mandated relocation projects is shown in Attachment D. Please note that capital expenditures shown in Attachment D and the plant in-service and capital expenditures shown in other parts of this report are shown net of reimbursements, and our revenue requirement is calculated net of reimbursements. As such no additional adjustments are needed for reimbursements.
4. Required Xcel Energy to provide a compliance filing, based on Commission decisions, within 10 days of Commission Order, including electronic files with formulae intact of the revenue requirement and corresponding rate factor schedules	Compliance Filing submitted on September 27, 2024.

Index of Attachments

Attachment	Item
A	Compliance Matrix
B	Index of Attachments
C	TIMP Overview
C1	TIMP Project Detail 2023-2025
C2	TIMP Quantitative Risk Assessment Scores for 2025
D	DIMP and Mandated Relocations Overview
D1	DIMP Project Detail 2023-2025
D2(a)	DIMP Quantitative Risk Assessment Scores for 2025
D2(b)	DIMP Replacements Risk Assessment Scores for 2025
E	Mandated Relocations Project Detail for 2023-2025
F	Capital TIMP, DIMP and Mandated Relocations Expenditures Actual and Forecast Through 2029
G	TIMP Capital Revenue Requirements for 2025
H	DIMP and Mandated Relocations Capital Revenue Requirements for 2025
I	Cost Comparison of Using Contractor vs. In-House Workforce and Equipment for Sewer Inspection
J	Calculation of Estimated Annual GUIC-Related Retirements for 2012-2025
K	TIMP and DIMP O&M Expense Actuals 2022 and Forecast 2024-2029
L	Universal Inputs

Index of Attachments

Attachment	**Item**
M	Magnitude of GUIC Rider in Relation to Last Approved Rate Case Docket No. G002/GR-21-678
N	Cost/Revenue Reconciliation to 2021 Jurisdictional Annual Report *Not in use. Held in reserve.*
O	Annual Revenue Requirement Tracker Summary for 2023-2029
P	Monthly Revenue Requirement Tracker Summaries for 2023-2025
Q	TIMP and DIMP Revenue Requirements Category Descriptions
R	Monthly Collection Pattern - GUIC Rate Factor Calculations
S	Carryover Rollforward: GUIC Over/Under Collection
T	Proposed Tariff Sheet No. 5-64 Revisions: Redline and Clean
U	Performance Metrics

Transmission Integrity Management Program
Overview and Project Detail

I. TIMP Overview

Our Transmission Integrity Management Program (TIMP) was developed pursuant to the Pipeline Safety Improvement Act of 2002 and the regulations promulgated by the Department of Transportation's (DOT) Office of Pipeline Safety. On December 17, 2004, we published a TIMP manual, in accordance with 49 C.F.R. § 192, Subpart O. The TIMP manual specifies procedures for gathering, integrating, and analyzing data; assessing pipelines; and implementing remedial actions to improve pipeline safety.

At its core, the TIMP can be summarized in three steps:

1) understand your assets,
2) risk evaluation, and
3) risk mitigation.

Our processes for these three steps are outlined below.

1. Understand Your Assets

For the TIMP to be successful, the Company needs to gather, evaluate, and integrate data in order to better understand our gas transmission system. The TIMP process has allowed us to update asset records and improve overall asset knowledge, as well as information on the surrounding area. Fundamentally, aspects about the physical and operating characteristics and ongoing integrity of a system need to be known. These aspects include date of installation and length, size, material, and operating pressure of the pipeline. In addition, information about the installation location of the gas transmission assets is also important, including class location, geotechnical data, and structures in the area.

Managing the risk of gas transmission assets is an ongoing process and evolves over time. The Company's baseline assessment plan prioritizes pipeline segments based on many factors, including population density, and the likelihood and severity of potential failure. The plan is updated regularly, incorporating new information on the health and condition of the assets and other system information.

2. *Risk Evaluation*

The Company evaluates the threats to a given pipeline that may pose a safety or reliability risk, with pipeline segments in populated areas[1] receiving the highest priority. Pipeline asset information from existing records, operating data, and input from subject matter experts (SMEs) is initially used to identify potential threats. Industry guidance materials, such as those published by the American Society of Mechanical Engineers, have also been incorporated into the threat identification process.

- The Company evaluates our gas transmission pipelines for the following threats: Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking
- Stable threats such as manufacturing, welding, fabrication, or construction defects
- Time independent threats such as third-party damage, mechanical damage, incorrect operations, weather related, and outside force damage to include consideration of seismicity, geology, and soil stability of the area
- Human error, such as operational or maintenance mishaps, or design and construction mistakes

Xcel Energy's risk assessment process identifies events or conditions that could cause or increase the likelihood or consequence of pipeline failure. The condition and the physical characteristics of its gas assets, along with industry guidance and directives, are incorporated into risk evaluations and subsequent risk mitigation strategies. This risk evaluation process provides information to facilitate decisions about the prioritization of health and condition assessments, the frequency of assessment, which assessment methodology is most appropriate, and in certain cases information to substantiate the need for replacement of an asset.

3. *Risk Mitigation*

The Pipeline Safety Action Plan[2] issued by the DOT in 2011 called for gas system operators to accelerate their efforts to replace pipeline facilities and take other actions to enhance the integrity of natural gas facilities. We integrate the results from our risk evaluation processes into determining planned risk mitigation activities. Typical risk

---

[1] Known as high consequence areas (HCA) and moderate consequence areas (MCA).
[2] https://www.phmsa.dot.gov/regulations-fr/rulemaking/2019-20306.

mitigation measures include excavation of the pipeline, repair, or complete removal of the anomaly, and reducing the operating pressure of the system.

Other risk mitigation activities focus on reducing consequences in the event of a failure. An example is the installation of specialized valves that can remotely or automatically shut down a pipeline, limiting or reducing the consequence in the event of a pipeline failure or rupture. These specific valves are commonly referred to as automatic shut-off valves (ASVs) or remote-controlled valves (RCVs).

In March of 2016, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Notice of Proposed Rulemaking (NPRM) under Docket No. PHMSA-2011-0023. This NPRM proposed revisions to the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. PHMSA proposed changes to the integrity management (IM) requirements as well as changes to non-IM requirements. The NPRM was originally published as one rule in 2016 and was later split into three separate rules. The first of the three rules was published on October 1, 2019.[3] The second rule was published on August 24, 2022.[4] Then PHMSA issued a limited enforcement discretion for RIN-2 ("mega rule part 2") on December 6 2022, extending some implementation requirements by nine months from May 24, 2023 to February 24, 2024. The third rule was published on November 15, 2021.[5]

The focus of the first rule is records retention, material verification, MAOP reconfirmation and integrity assessments outside of HCAs. The rule carries progressive effective dates, the first of which was July 1, 2020, but was extended to December 31, 2020, due to the impacts of COVID-19. The 2025 GUIC includes MAOP reconfirmation projects and costs needed to comply with this new rule.

The specific IM requirement changes from the first rule include:

- Expansion of IM beyond high consequence areas (HCAs),
- Establishment of moderate consequence areas (MCAs),
- Maximum Allowable Operating Pressure (MAOP) validation and reconfirmation,
- Materials verification requirements, and
- Spike testing.

[3] Docket No. PHMSA-2011-0023; Amdt. Nos. 191-26; 192-125.
[4] Docket No. PHMSA-2011-0023; Amdt. No. 192-132.
[5] Docket No. PHMSA-2011-0023; Amdt. Nos. 191-30; 192-129.

The IM requirement changes from the second rule include:

- HCA and non-HCA assessment response criteria
- Corrosion control,
- Risk assessment requirements,
- New construction and repairs,
- Management of change, and
- Inspection of pipelines following weather events.

Finally, the IM requirement changes from the third rule addresses the expansion of regulated gas gathering lines.

In summary, risk mitigation can include initiating preventative measures, more frequent inspections and health and condition assessments, utilizing specialized technology to address a specific threat, repair, or replacement of anomalous conditions along a pipeline, or complete replacement of a given asset. As part of its comprehensive IM program, the Company has identified different risk mitigation strategies intended to reduce the likelihood of consequences posed by threats.

The 2025 TIMP project detail is presented in Attachment C1, and the risk assessment scores for 2025 TIMP projects are presented in Attachment C2.

II. 2025 TIMP Projects

In this filing, the Company requests recovery of the following operational and maintenance (O&M) and capital expenditures associated with five 2025 TIMP programs:

2025 Estimated TIMP Project Costs
($ Millions)

Program	2025 Capital	2025 O&M
Transmission Pipeline Assessments	$0.94	$0.55
Transmission Pipeline Assessment Sleeve Repair	$0.10	$0.00
ASV/RCV	$0.00	$0.00
Programmatic Replacement / MAOP Remediation	$3.88	$0.00
Transmission Rule	$0.00	$0.05
Casing Renewal	$11.12	$0.00
Total 2025 TIMP Expenditures	**$16.04**	**$0.60**
Total 2025 Minnesota TIMP Revenue Requirement	**$3.38**	**$0.53**

These projects, except for Casing Renewal, Sleeve Repair, and Transmission Rule, were included in the Company's 2015 through 2024 Gas Utility Infrastructure Cost (GUIC) Rider petitions.[6] The Casing Renewal project began in 2021. The capital-related cost estimates for 2025 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads. The 2025 project detail for each project is presented in Attachment C1 and the risk assessment scores for 2025 projects are presented in Attachments C2.

Projects planned for completion in 2025 and outlined below will begin during the 2nd and 3rd quarters of 2025 and will be placed in service during the 3rd and 4th quarters of 2025.

1) Transmission Pipeline Assessments & Sleeve Repair
Work Breakdown Structure (WBS):[7] E.0000018.052, E.0010073.016 (Capital); A.0008610.004.002.002 (O&M)

<u>2025 Estimated Project Costs</u>:
$1.04 million Capital expenditure
$0.55 million O&M expenditure

<u>Project Summary and Scope</u>
This project is an ongoing program, beginning in 2002, of health and condition assessments on gas transmission lines. Federal regulations require assessment of gas transmission pipelines using In Line Inspection (ILI), pressure testing or direct assessment.[8] Regular assessment of pipelines is based on the health and condition of the assets as well as an evaluation of the risks and threats.

The Company met the HCA Baseline Assessment requirements,[9] and is now focusing on the reassessment of pipelines in HCAs as well as assessing remaining transmission pipe beyond HCAs. The program includes requirements to ensure the safe operation of all gas transmission pipelines under American Society of Mechanical Engineers Standard B31.8S.[10]

---

[6] Docket Nos. G002/M-14-336, G002/M-15-808, G002/M-16-891, G002/M-17-787, G002/M-18-692, G002/M-19-664, G002/M-20-799, and G002/M-21-765.
[7] WBS has replaced the parent project number for projects in previous GUIC Rider filings. This switch in numbering has been due to a change in our work and asset management system.
The previously used parent projects generally correspond with one WBS.
[8] The requirements are further defined in the Company's TIMP manual.
[9] Federal requirements stipulated that all pipelines in HCAs needed to be assessed by December 17, 2012.
[10] This standard is incorporated by reference into 49 C.F.R. § 192, Subpart O.

The Company has selected ILI as the primary assessment methodology due to its superior ability to provide detailed information regarding the current pipeline condition over the entire length of the line. However, based on the threats to which a pipeline is susceptible and the feasibility of assessment methodologies, the Company may choose to utilize direct assessment and pressure testing as the primary or complementary assessment methodologies.

ILI requires unique inspection equipment and specialized knowledge. Outside vendors maintain fleets of such tools, which may cost upwards of $1 million, and have the expertise needed to analyze data collected during an ILI. Additionally, ILI tools are constantly being re-engineered to gather more information about the health and condition of pipelines which makes owning such tools uneconomic at this time. Working with outside contractors to complete this work provides access to specialized expertise and equipment that is outside of the Company's normal scope of business and ensures that assessments are completed safely and efficiently.

Federal regulation requires the Company to apply knowledge gained from all assessments to all similar pipelines within the system, both inside and outside HCAs. While the initial investment incurred to make lines accessible to ILI tools can be significant, the benefit of this investment is the ability to assess for multiple threats, gather a more comprehensive profile of the integrity of a pipeline, and complete assessments over longer distances.

There are two distinct elements in the selection and prioritization of work to be performed in this program: the assessment of pipelines and addressing issues found during the assessment. Assessment work in prior years was primarily driven by the date and type of the previous assessment. Findings from initial assessments can and do impact the timing of subsequent assessments, with a maximum interval of at least once every seven years. The objective is to monitor anomalies found on the pipelines, assess if they are stable or deteriorating, and mitigate the anomaly before it becomes a threat to public safety.

The Company evaluates anomalous conditions found during the assessment including the location of the anomaly, severity, nature (threat cause), and type of feature (e.g., dent or metal loss). The potential for other locations along the pipeline or in the system where similar conditions may exist is also considered and evaluated. Based on this evaluation, the Company categorizes the anomaly into an immediate condition, one–year condition, or monitored condition. These conditions are used to prioritize remediations. A typical remediation may include excavation and repair, removal of the anomaly, and/or reducing the operating pressure of the system.

The cost of TIMP assessments is highly variable and depends on the assessment method, pipeline age, configuration, as well as seasonal and operational constraints.

The scope of work in 2025 includes three projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Montreal Line N	Reassessment ILI	0.3	Capital/O&M
Highbridge Line	Reassessment ILI	2.6	Capital/O&M
Blue Lake Line	Reassessment ILI	10.9	Capital

- **Montreal Line North:** This project involves reassessment of approximately .3 miles of 20- & 24-inch pipeline utilizing in line inspection. Costs associated with a second time ILI are typically classified as O&M and most repairs as a result of ILI assessment are capitalized, but some repairs may be classified as O&M per the Company's capitalization policy.

- **Highbridge Line:** This project involves reassessment of approximately 2.6 miles of 16-inch pipeline utilizing in line inspection. Costs associated with a second time ILI are typically classified as O&M and most repairs as a result of ILI assessment are capitalized, but some repairs may be classified as O&M per the Company's capitalization policy.

- **Blue Lake Line:** During the 2024 assessment it was discovered that there was a high induced AC voltage on our pipeline due to interference with the overhead power lines. Having high AC induced voltage is a personnel electrical shock risk and also sometimes can cause very aggressive corrosion on the pipeline. In 2025 it is planned to install an AC mitigation system on the Blue Lake Pipeline to greatly reduce electrocution and corrosion risks to personnel and the pipeline. Installation of an AC mitigation system is classified as capital costs per the Company's capitalization policy.

Costs for direct assessment and direct examination are classified as O&M per the Company's capitalization policy. Due to the generally non-invasive nature of direct assessment activities, the cost is generally related to the length of pipe evaluated with some variability due to the route, depth, and environment of the pipeline (open field, natural forest, in the road ditch, under a major highway, etc.).

The costs to modify pipelines for initial ILI runs are capital costs per the Company's capitalization policy. This includes vendor costs associated with the use of specialized ILI tools and the advanced analysis required to interpret the results. Once an initial ILI assessment is completed on a specific section of pipeline, all costs for subsequent assessment by ILI will be O&M with the exception of repairs resulting from data collected during ILI runs, in most cases repair costs are capitalized. The costs for assessment by pressure test including test equipment, test medium, and disposal of medium will be classified as O&M in all cases.

Repairs to existing pipelines involving cut-out of the existing pipe or sleeve repairs are defined by the capitalization policy as Capital. If a cut-out is required, capitalization policy defines the O&M or capital designation based upon the length of the required cut-out.

2) ASVs and RCVs
WBS: E.0000018.041 (Capital)

2025 Estimated Project Costs:
$0.00 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope:
N/A

3) Programmatic Replacement/MAOP Remediation & Transmission Rule
WBS: E.0010073.011 (Capital);
WBS: A.0008610.004.002.003, A.0008610.004.002.004 (O&M)

2025 Estimated Project Costs:
$3.88 million Capital expenditure
$0.05 million O&M expenditure

Project Summary and Scope

The MAOP Remediation Advisory Bulletin[11] issued by PHMSA in 2012, and contained in the Federal Register, specifically addressed pipeline safety in terms of verification of records. The initial language in the advisory required operators to "take action as appropriate to assure that all MAOP and MOP [Maximum Operating Pressure] are supported by records that are traceable, verifiable, and complete." As discussed earlier, the first of the three new PHMSA Gas Transmission and Gathering Pipeline final rules was published in October of 2019. The focus of the first rule is records retention, material verification, MAOP reconfirmation and integrity assessments outside of HCAs. The codes and rules around material testing, welding standards, and record keeping have evolved over time. Consequently, the Company acknowledges there are gaps in data regarding our facilities that need to be closed to meet the Federal standards. Some data gaps are more critical than others. For instance, the construction and maintenance data of gas transmission pipelines and operating pressures are critical to support the safe operation of these assets. The MAOP initiative focuses on obtaining adequate proof of MAOP records and ensuring that they become part of the Company's official system of record. Remediation of data gaps is also part of the scope.

In the new rule published on October 1, 2019, PHMSA required operators to reconfirm MAOP for the following categories:

1) Grandfathered pipelines in HCAs, MCAs, and Class 3 and 4 locations
2) Pipelines for which records to support the MAOP are not traceable, verifiable, and complete in:
    a. HCAs,
    b. Class 3 and 4 locations
    c. Piggable grandfathered pipelines operating at greater than 30% SMYS within MCAs

Pipelines are prioritized for renewal and/or pressure tested based on a variety of factors and competing demands, including:

- Location within or outside of HCAs,
- Class Location,
- Type of documentation missing, and
- Criticality to system.

[11] ADB-12-06, Docket No. PHMSA-2012-0068.

The MAOP review portion of the work will be completed by hiring contract engineering and research analysts. The Company's internal engineering department will assist in the design of the remediation projects with the project management group's oversight. Material procurement will be completed using our current agreements with our vendors and using our Company sourcing group to ensure we receive the best prices and delivery schedules.

The cost estimates for this program are based on our experience with similar assets in prior years. Actual results from assessments will drive the overall scope and timing of these capital expenditures.

In 2025 we will perform the following work:

Line/Loop	Type	Project Length (mi)	Project Type
TL0205/Montreal Line	Pressure Test / Renew	0.26	Capital
Various Regulator Stations	Pressure Test	3 Stations	Capital
Various Station/Mainline Testing	Material Verification	-	O&M
East County Line	Replace	0.03	Capital
East County Line (West of the Mississippi)	Pressure Test	0.26	Capital

- **<u>TL0205/Montreal Line:</u>** As a part of MAOP reconfirmation and document reviews, the company plans to execute a pressure test on approximately 0.26 miles of main on the Montreal Line. The project will be designed in 2025 and executed in 2026. A section of this is also under review for possible conflict with MN DOT roadway improvement project.

- **<u>Regulator Stations:</u>** As a part of MAOP reconfirmation and document reviews, the Company plans to execute pressure tests on approximately three transmission regulator stations in 2024. Individual station remediation projects will be determined in late 2024 or early 2025.

- **<u>Materials Documentation</u>:** As part of MAOP reconfirmation, the Company needs to perform material verification on stations and mainlines where pressure test documentation is adequate, but materials documentation is not. In 2024, this will entail field verification of station components and mainline pipe.

- **East County Line:** As a part of MAOP reconfirmation and document reviews, the Company executed a replacement on approximately 0.03 miles of main on the East County Line. The project was designed in 2022-2023 and executed in 2023-2025.

- **East County Line (West of the Mississippi):** As a part of MAOP reconfirmation and document reviews, the company will execute a pressure test on approximately 0.26 miles of main on the East County Line. The project was designed in 2022-2023 and executed in 2024-2025.

Cost associated with pressure testing and replacement are classified as capital per the Company's capitalization policy.

4) Casing Renewal
WBS: E.0010073.006 (Capital)

2025 Estimated Project Costs:
$11.12 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
This project is similar to the shorted casing – Distribution Project (see prior discussion). As an integrated part of the Company's DIMP plan, similar needs have been identified as part of TIMP for Transmission pipelines, which is a principal requirement of managing risk under integrity management programs. Metallic pipes need to remain isolated from each other to reduce corrosion risk. The Company's Pipeline and Compliance Standards Manual section 9.9.9 and 49 C.F.R. § 192.467 provide that for all metallic carrier pipe installed in a metallic casing, the Company shall take pipe-to-soil and casing-to-soil readings annually to determine whether the two pieces of pipe are in contact with each other, and thereby considered to be shorted. If the Company is unable to verify those readings and/or the readings indicate that both the pipe and casing are in contact, the Company shall perform gas leak surveys at a minimum of two times per year – four times per year in business districts – given the potential for corrosion between the two pieces of pipe.

Under this project, the Company isolates pipes and casings that are determined to be shorted (or unable to take readings), mitigates leakage risk for sites that indicate the presence of corrosion or where testing has not occurred, and replaces pipe where it is not possible to test or isolate the pipe.

This project started in the 2021 construction season and shall continue annually until all casings risks on the program list have been mitigated. The locations proposed for replacement in 2025 and beyond are based on risk analysis originally completed in 2020 and reviewed in 2022.

The 2025 scope of work includes the following casing:

Casing Location	Pipe Size	Leaking	Shorted
20-inch Pt Douglas & Springside	20"	No	Unknown

The existing 20-inch-high pressure transmission pipeline at Pt Douglas and Springside has a casing without test leads and therefore pipe to soil readings are not possible. This project entails renewing the US Highway 10/61 crossing with new and uncased 20-inch steel piping.

Note: This project was originally planned to be completed in 2024. Upon field investigation, it was determined that the tie-in point on the west side of Hwy 61 was inaccessible due to the close proximity of the highway, retaining wall, as well as the RR tracks. It is not possible to reasonably construct on that side of the highway. An alternative route will be designed in 2024 with planned construction in 2025.

III. 2024 TIMP Projects

In 2024, there are four projects under the TIMP:

1) Transmission Pipeline Assessments,
2) ASVs and RCV,
3) Programmatic Replacement / MAOP Remediation, and
4) Casing Renewal

The TIMP project costs included in the Company's 2024 GUIC Rider Petition, Docket No. G002/M-23-457, as compared to updated 2024 cost estimates[12] based on emerging project developments and actual construction activity, are provided below:

[12] Based on actual costs as of 6/30/2024 and estimates from 7/1/2024 through 12/31/2024.

2024 Estimated TIMP Project Costs
($ Millions)

TIMP Program	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Transmission Pipeline Assessments	$0.32	$0.37	$0.05	15.6%	$1.25	$0.84	($0.41)	-33%
ASV/RCV	$0.00	$0.00	$0.00	0.00%	$0.00	$0.00	$0.00	0.00%
Programmatic Replacement / MAOP Remediation	$3.40	$3.10	($0.30)	-8.8%	$0.45	$0.31	($0.14)	-31.1%
Casing Renewal	$0.73	$0.69	($0.04)	-5.5%	$0.00	$0.00	$0.00	-
Transmission Rule	$0.00	$0.00	$0.00	-	$0.05	$0.03	($0.02)	-40%
Total 2024 TIMP Capital Expenditures and O&M	**$4.45**	**$4.15**	**($0.30)**	**-6.7%**	**$1.75**	**$1.18**	**($0.57)**	**-32.6%**
Total 2024 Minnesota TIMP Revenue Requirement	**$2.59**	**$2.50**	**($0.09)**	**-3.70%**	**$1.54**	**$1.04**	**($0.50)**	**-32.60%**

The capital-related cost estimates for 2024 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads not related to internal labor. TIMP projects planned for completion in 2024 and outlined below generally began during the 2nd and 3rd quarters of 2024 and will begin service during the 3rd and 4th quarters of 2024.

1) Transmission Pipeline Assessments
WBS: E.0000018.052 (Capital); A.0008610.004.002.002 (O&M)

Project Summary and Scope

The scope of assessments in 2024 includes four projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Blue Lake Line	Reassessment ILI	10.9	Capital/O&M
Rosemount Line	Reassessment ILI	7.9	Capital/O&M
Island Line S	Inspection/Repairs	N/A	Capital
Lake Elmo Line	Inspection/Repairs	N/A	Capital

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.32	$0.37	$0.05	15.6%	$1.25	$0.84	($0.41)	-33%

Variance Explanation

Capital: Capital variance is mainly due to two separate instances. First is the Lake Elmo Line capital repair. The Lake Elmo line successfully underwent ILI in 2023, but the validation dig location was within Union Pacific Railroad right-of-way and permitting delays pushed this project from 2023 into 2024.

Second is the Blue Lake ILI project, when conducting prework for the project it was determined that the AC mitigation system which protects our facilities and personnel from induced AC current from overhead power lines had failed and needed to be repaired in order to safely complete the ILI assessment. This work was completed in Q2 of 2024.

O&M: The O&M variance is due to changing the scope of the Island Line S project from a reassessment ILI into a dig and material verification project. A recent determination has given Xcel Energy a path to non-destructively test in-service pipe for steel strength. The Island Line S pipeline original construction lacks tracible, verifiable, and complete records and because of that is listed as a lower strength steel than we anticipate due to ancillary documentation. We expect to review the test results and be able to attribute higher steel strength to this pipeline segment which will reassign this pipeline to a distribution line and save costs for further TIMP inspections.

Please note the variances between capital and O&M are not equal as the change in capital considers a portion of the costs will be related to internal labor and therefore non GUIC recoverable.

2) ASVs and RCVs
WBS: E.0000018.041 (Capital)

2024 Estimated Project Costs:
$0.00 million Capital expenditure
$0.00 million O&M expenditure

Project Summary and Scope
N/A - No ASVs or RCVs projects in 2024.

Valve Location	Size	Description
N/A	N/A	No ASVs or RCVs Projects in 2024

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.00	$0.00	$0.00	--	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: None

O&M: None

3) Programmatic Replacement/MAOP Remediation & Transmission Rule
WBS: E.0010073.011, E.0010043.030, E.0010073.018 (Capital)
WBS: A.0008610.004.002.004 (O&M)

Project Summary and Scope
In 2024 the scope of work includes two projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
East County Line	Replace	0.5	Capital
East County Line (West of the Mississippi)	Pressure Test	1.6	Capital

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$3.40	$3.10	($0.30)	-8.8%	$0.45	$0.34	($0.11)	-24.4%

Variance Explanation

Capital: The decrease in capital expenditures was due to unforeseen flooding conditions that significantly delayed our access to the remaining replacement work on the east side of the river. This replacement work has been deferred to 2025.

O&M: None.

4) Casing Renewal
WBS: E.0010073.006, E.0010073.019 (Capital)

Project Summary and Scope

This project started in the 2021 construction season and shall continue annually until all casings risks on the program list have been mitigated. The locations proposed for replacement in 2024 are based on risk analysis originally completed in 2020 and reviewed in 2024.

The 2024 scope of work includes the following casing:

Casing Location	Pipe Size	Leaking	Shorted
20-inch Pt Douglas & Springside	20”	N	Unknown

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.73	$0.69	($0.04)	-5.5%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: This project was originally planned to be completed in 2024. Upon field investigation, it was determined that the tie-in point on the west side of Hwy 61 was inaccessible due to the close proximity of the highway, retaining wall, as well as the RR tracks. It is not possible to reasonably construct on that side of the highway. An alternative route will be designed in 2024 with planned construction in 2025.

O&M: None.

IV. 2023 TIMP Projects

In 2023, there were four projects under the TIMP:

1) Transmission Pipeline Assessments,
2) ASVs and RCVs,
3) Programmatic Replacements and MAOP Remediation, and
4) Casing Renewal.

The following are the TIMP project costs included in the Company's 2023 GUIC Rider Petition, Docket No. G002/M-22-578, as compared to actual 2023 costs.

2023 Actual TIMP Project Costs
($ Millions)

Program	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Transmission Pipeline Assessments	$0.26	$0.43	$0.18	68.99%	$0.63	$0.46	($0.16)	26.29%
ASV/RCV	$0.00	$0.00	$0.00	-	$0.00	$0.00	$0.00	-
Programmatic Replacement / MAOP Remediation	$8.64	$6.16	($2.48)	-28.68%	$0.05	$0.00	($0.05)	-
Casing Renewal	$2.10	$3.70	$1.60	76.19%	$0.00	$0.00	$0.00	0.00%
Total 2023 TIMP Capital Expenditures and O&M	**$11.00**	**$10.30**	**($0.70)**	**-6.35%**	**$0.68**	**$0.46**	**($0.21)**	**31.75%**
Total 2023 Minnesota TIMP Revenue Requirement	**$13.67**	**$8.83**	**($4.83)**	**-35.38%**	**$0.55**	**$0.46**	**($0.09)**	**16.91%**

TIMP projects completed in 2023 and outlined below generally began during the 2nd and 3rd quarters of 2023 and were placed into service during the 3rd and 4th quarters of 2023.

1) Transmission Pipeline Assessments
WBS: E.0000018.052 (Capital); A.0008610.004.002.002, A.0008510.114.002.002 (O&M)

Project Summary and Scope

The project scope in 2023 included three projects on the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Wescott Line 8-inch	Baseline ILI	1.6	Capital/O&M
Wescott Line 12-inch	Baseline ILI	1.6	Capital/O&M
Island Line North	Direct Examination	0.01	O&M

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.26	$0.43	$0.18	68.99%	$0.63	$0.46	($0.16)	-26.29%

Variance Explanation

Capital: Two main factors affect the capital variance, first is the fact that when originally forecasting projects it was assumed that both the Wescott 8 & 12" ILI make piggable work could be done concurrently. System constraints only allowed us to complete work on one line at a time, this increased our construction time by approximately three weeks and is associated with these higher capital costs. A second, smaller increase in capital expenditures is due to a determination by Capital Asset Accounting that sleeve repairs can be classified as capital repairs, and greater than expected construction costs and timeline on the Wescott lines.

O&M: The variance is due to a determination by Capital Asset Accounting that sleeve repairs can be classified as capital repairs; historically, these repairs were considered O&M.

Please note the variances between capital and O&M are not equal, as the change in capital considers a portion of the costs will be related to internal labor and therefore non GUIC recoverable.

2) ASVs and RCVs
WBS: E.0000018.041 (Capital)

Project Summary and Scope
N/A - No ASVs or RCVs projects in 2023.

Valve Location	Size	Description
N/A	N/A	No ASVs or RCVs Projects in 2023

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.00	$0.00	$0.00	-	$0.00	$0.00	$0.00	-

Variance Explanation

Capital: None.

O&M: None.

3) Programmatic Replacement/MAOP Remediation WBS: E.0010043.030, E.0010073.018 (Capital)

Project Summary and Scope

Expenses relate to engineering and design work on the following line:

Line/Loop	Type	Project Length (mi)	Project Type
East County Line	Replace	0.5	Capital
East County Line (West of the Mississippi)	Pressure Test	1.6	Capital

The East County Line Pressure Test was pushed to 2024 due to low estimated costs of the entire East County Line MAOP remediation that needs to occur. It was determined there was insufficient funding to complete the replacement work, the casing work at Hwy 494 & Hardmann Ave, and the pressure test work. The replacement work was underestimated in the areas of environmental remediation due to a landfill adjacent to the Xcel Energy property, unknown rock which also slowed productivity, causing additional costs. The Contractor's rates also increased in the contract, raising the cost of the bore under I-494.

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$8.64	$6.16	($2.48)	-28.68	$0.05	$0.00	($0.05)	-

Variance Explanation

Capital: In 2023 the replacement work came in lower than estimated due to the project needing to be expanded into 2024 and 2025. Overall, the project was higher than estimated, as a sum of both the pressure test and the replacement work, the variance is due to moving the pressure test work to 2024 as well as decreasing the replacement work by ~150 LF to include a design of a launcher/receiver needed on the east side of the river which is planned for 2025.

O&M: None.

4) Casing Renewal
WBS: E.0010073.006, E.0010073.019 (Capital)

Project Summary and Scope

The 2023 scope of work included the following casing:

Casing Location	Pipe Size	Leaking	Shorted
24 inch High Pressure at Hardman and 494	24"	N	Unknown
16in Rosemount Line Crossing at Cahill	16"	N	Unknown

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$2.10	$3.70	$1.60	76.19%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The increase in capital expenditures was due to an increase in the Contractor contract prior to execution of the process. Replacement of the asphalt was also not factored into the original estimate. Due to the contract with the Union which states that the Union must be given the first right to any project under 1,800 LF, the internal Union employees led the project. However, a Contractor was still needed to support the work and complete the hydrotest. This addition of staff was not accounted for in the original estimate.

O&M: None.

V. TIMP MULTI-YEAR PLAN

As previously stated, some of the TIMP projects will span multiple years. As such, the Company has formulated a multi-year plan for those that will extend beyond 2025.

The table below depicts the estimated capital and O&M costs for this multi-year plan. Many of these projects require more detailed design and engineering work to improve the quality of the estimate. Other factors, including coordination with city entities, securing rights-of-way and permits, resource and equipment availability, and unforeseen circumstances all can have an impact on a final construction estimate.

The information provided below is an initial high-level budgeting estimate for each program.

TIMP 2026-2029 Plan[13]
($ Millions)

	2026 Estimates		2027 Estimates		2028 Estimates		2029 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Transmission Pipeline Assessments	$1.15	$0.73	$1.82	$0.60	$0.38	$0.80	$0.39	$0.82
Transmission Pipeline Assessment Sleeve Repair	$0.10	$0.00	$0.10	$0.00	$0.19	$0.00	$0.19	$0.00
ASV/RCV	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Programmatic Replacement / MAOP Remediation	$2.57	$0.00	$2.57	$0.00	$2.57	$0.00	$2.63	$0.00
Transmission Rule	$0.00	$0.05	$0.00	$0.06	$0.00	$0.06	$0.00	$0.06
Casing Renewal	$1.88	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**$5.70**	**$0.78**	**$4.49**	**$0.66**	**$3.13**	**$0.86**	**$3.21**	**$0.88**

[13] Capital figures denoted represent total estimated capital expenditures, including removal costs.

Northern States Power Company

Docket No. G002/M-24-____
Gas Utility Infrastructure Cost Rider - 2025 Factors
Attachment C1 - Page 1 of 1

TIMP 2023-2025 Project Detail

CAPITAL

Program	Regulation	WBS Structure	2023 Actuals	2024 Actuals [1]	2024 Forecast	2024 Total	2025 Plan	Cost Per Unit (CPU) Assumptions
TIMP Assessments & Sleeve Repair	49 CFR Part 192, Subpart O	E.0000018.052 E.0010073.016	$ 430,927	$ 129,193	$ 240,511	$ 369,704	$ 1,042,000	See Attachment C1(a)
ASV/RCV Replacements	49 CFR Part 192.935	E.0000018.041	$ -	$ -	$ -	$ -	$ -	See Attachment C1(b)
Programmatic Replacement/MAOP Validation	On May 7, 2012, the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an Advisory Bulletin to clarify the record verification requirements for establishing Maximum Allowable Operating Pressure (MAOP) for natural gas pipelines. See http://www.gpo.gov/fdsys/pkg/FR-2012-05-07/pdf/2012-10866.pdf.	E.0010043.030 E.0010073.011 E.0010073.018 E.0000042.001	$ 6,162,346	$ 489,866	$ 2,603,478	$ 3,093,344	$ 3,875,000	See Attachment C1(c)
Casing Renewal	49 CFR Part 192.467	E.0010073.006 E.0010073.019	$ 3,703,931	$ 4,328	$ 681,427	$ 685,755	$ 11,124,000	See Attachment C1(d)
TOTAL TIMP CAPITAL			**$ 10,297,203**	**$ 623,387**	**$ 3,525,416**	**$ 4,148,803**	**$ 16,041,000**	

O&M

Program	Regulation	WBS Structure	2023 Actuals	2024 Actuals [1]	2024 Forecast	2024 Total	2025 Plan	Cost Per Unit (CPU) Assumptions
TIMP Assessments	49 CFR Part 192, Subpart O	A.0008610.004.002.002	$ 460,680	$ 526,513	$ 310,000	$ 836,513	$ 550,000	See Attachment C1(a)
TIMP Transmission Rule	49 CFR Part 192.607	A.0008610.004.002.004	$ -	$ -	$ 25,000	$ 25,000	$ 52,000	See Attachment C1(c)
MAOP Reconfirmation	49 CFR Part 192.624	A.0008610.004.002.003	$ -	$ -	$ 314,400	$ 314,400	$ -	See Attachment C1(c)
TOTAL TIMP O&M			**$ 460,680**	**$ 526,513**	**$ 649,400**	**$ 1,175,913**	**$ 602,000**	

[1] Actual costs through June 2024.

TIMP 2023-2025 Project Detail - Assessments

2023				
Line/Loop	**Project Description**		**Actual Cost**	**O&M or Capital**
Rosemount Line - Inver Hills Lateral	**2nd ILI**	**$**	**298,899**	
Task 1	Capital ILI Repairs	$	147,484	Capital
Task 2	Pigging Runs/Validation Digs	$	151,415	O&M
Lake Elmo Line	**2nd ILI**	**$**	**326,483**	
Task 1	Capital ILI Repairs	$	4,366	Capital
Task 2	Pigging Runs/Validation Digs	$	322,117	O&M
Blue Lake Line	**2nd ILI**	**$**	**401,304**	
Task 1	Make piggable modifications	$	401,304	Capital
East County Line	**Baseline ILI/ECDA**			
Task 1	Pipe Support Installation	$	44,569	O&M
Island Line North	**Direct Examination**			
Task 1	Carryover Costs	$	2,531	O&M
	Total Capital	**$**	**553,154**	
	Total O&M	**$**	**520,632**	

* Amounts above include non-GUIC recoverable costs associated with internal labor.

2024				
Line/Loop	**Project Description**		**Estimated Cost**	**O&M or Capital**
Rosemount Line	**Reassessment ILI**	**$**	**617,413**	
Task 1	Capital ILI Repairs	$	75,000	Capital
Task 2	Pigging Runs/Validation Digs	$	542,413	O&M
Blue Lake Line	**2nd ILI**	**$**	**493,362**	
Task 1	Capital ILI Repairs	$	200,000	Capital
Task 2	Pigging Runs/Validation Digs	$	293,362	O&M
Island Line South	**Inspection/Repair**	**$**	**200,000**	
Task 1	Capital ILI Repairs	$	200,000	Capital
East County Line	**Baseline ILI/ECDA**	**$**	**1,345**	
Task 1	Carryover Costs	$	1,345	O&M
Lake Elmo Line	**Inspection/Repair**	**$**	**150,000**	
Task 1	Capital ILI Repairs	$	150,000	Capital
Task 2	Pigging Runs/Validation Digs	$	646	O&M
	Total Capital	**$**	**625,000**	
	Total O&M	**$**	**837,765**	

* Amounts above include non-GUIC recoverable costs associated with internal labor.

2025				
Line/Loop	**Project Description**		**Estimated Cost**	**O&M or Capital**
Montreal Line N	**Reassessment ILI**	**$**	**450,000**	
Task 1	Capital ILI Repairs	$	150,000	Capital
Task 2	Pigging Runs/Validation Digs	$	300,000	O&M
Highbridge Line	**Reassessment ILI**	**$**	**400,000**	
Task 1	Capital ILI Repairs	$	150,000	Capital
Task 2	Pigging Runs/Validation Digs	$	250,000	O&M
Blue Lake Line	**Reassessment ILI**	**$**	**740,000**	
Task 1	AC Mitigation System	$	740,000	Capital
	Total Capital	**$**	**1,040,000**	
	Total O&M	**$**	**550,000**	

* Amounts above include non-GUIC recoverable costs associated with internal labor.

TIMP 2023-2025 Project Detail - ASV/RCV

2023			
Subproject	**Size**	**Description**	**Estimated Cost**
None			$0
		Total	**$0**
2024			
Subproject	**Size**	**Description**	**Estimated Cost**
None			$0
		Total	**$0**
2025			
Subproject	**Size**	**Description**	**Estimated Cost**
None			$0
		Total	**$0**

TIMP 2023-2025 Project Detail - Programmatic Replacement/MAOP Validation

2023

Individual Project Name	Project Description	Actual Cost	O&M or Capital
East County Line (Mississippi River to Carver Ave and Highway 61)	Replace approximately 2,400' of pipeline	$ 6,001,000	Capital
East County Line (West of the Mississippi)	Pressure Test approximately 8,500' of pipeline - design only	$ 168,000	Capital
County Road B Phase 2	True Up of Contract Labor on a replacement started in 2020.	$ (6,723)	Capital
MAOP (Records Verification)	Pressure test analysis on approximately eight pipelines totaling approximately 22 miles	$ -	O&M
	Total Capital	**$ 6,162,277**	
	Total O&M	**$ -**	

2024

Individual Project Name	Project Description	Estimated Cost	O&M or Capital
Regulator Stations	Engineer and execute three stations	$ -	Capital
Transmission Rule	Programmatic Material Verification	$ 25,000	O&M
MAOP (Records Verification)	Material Verification for stations and mainline that have adequate pressure test documentation but not material documentation.	$ 314,400	O&M
East County Line (West of the Mississippi)	Pressure Test approximately 7000' of pipeline, 1500' delayed to 2025 due to flooding conditions	$ 310,210	Capital
East County Line (Mississippi River to Carver Ave and Highway 61)	Replace approximately 2,400' of pipeline. Delayed to 2025 due to flooding conditions	$ 2,783,134	Capital
	Total Capital	**$ 3,093,344**	
	Total O&M	**$ 339,400**	

2025

Individual Project Name	Project Description	Estimated Cost	O&M or Capital
Regulator Stations	Engineer and execute three stations	$ 3,375,000	Capital
TL0205/Montreal Line	Engineer/planning	$ 500,000	Capital
Transmission Rule	Programmatic Material Verification	$ 52,000	O&M
MAOP (Records Verification)	Material Verification for stations and mainline that have adequate pressure test documentation but not material documentation.	$ -	O&M
East County Line (West of the Mississippi)	Pressure Test approximately 1500' of pipeline and modify valve stations on either side of the river to accommodate pressure test.	$ -	Capital
East County Line (Mississippi River to Carver Ave and Highway 61)	Replace approximately 2,400' of pipeline. Delayed to 2025 due to flooding conditions	$ -	Capital
	Total Capital	**$ 3,875,000**	
	Total O&M	**$ 52,000**	

TIMP 2023-2025 Project Detail - Casing Renewal

2023				
Casing Location	**Size**	**Leaking**	**Shorted**	**Estimated Cost**
24in High Pressure at Hardman and 494	24"	N	Unknown	$ 3,394,681
16 inch Rosemount Line Crossing at Cahill	16"	N	Unknown	$ 309,250
			Total	**$ 3,703,931**

2024				
Casing Location	**Size**	**Leaking**	**Shorted**	**Estimated Cost**
20in High Pressure at Pt Douglas & SpringSide	20"	N	Unknown	$ 685,755
			Total	**$ 685,755**

2025				
Casing Location	**Size**	**Leaking**	**Shorted**	**Estimated Cost**
20in High Pressure at Pt Douglas & SpringSide	20"	N	Unknown	$ 11,120,000
			Total	**$ 11,120,000**

Quantitative Risk Assessment for 2025 GUIC Programs and Initiatives

TIMP

Methodology

Xcel Energy's risk assessment methodology is a process to evaluate unwanted consequences and the likelihood of the consequences occurring on the Company's natural gas infrastructure. The goal of the Company's integrity programs is to protect the public, property, and the environment from pipeline failures.

The purpose of this risk assessment methodology is to develop a quantitative risk score and assign a risk category (high, medium, low) for identified projects that are funded through the Company's GUIC Rider.

These quantitative risk assessment methodologies assign numeric values to likelihood and consequences by using available data and quantifying assessments. In some cases, subject matter expert (SME) input is utilized.

TIMP Transmission Pipeline Assessments
Replacement Project Risk

2025 Projects by Risk Category
None

Data Inputs: Findings from completed pipeline assessments and pipeline patrols. Data and information is gathered and integrated for the pipeline segment that could be relevant. In some cases, replacement may be required due to the inability to assess for an applicable threat as required by Subpart O of 49 CFR 192.

Risk = Σ (Likelihood x Consequence) for all threats

<u>Likelihood of Failure Lookup Table</u>

Likelihood of Failure Score (L) = 0 if there are no known defects or situations of concern for the threat category. When known issues exist the following table is utilized.

TIMP Quantitative Risk Assessment Scores for 2025

Threat Category	L = 5	L = 3	L = 0.25
External Corrosion	An immediate repair condition as per 192.933(d)(1) Any metal-loss indication affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding. Predicted metal loss greater than 80% of the nominal wall thickness. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	A calculation of the remaining strength of the pipe shows a defect may grow to an immediate repair condition prior to the next scheduled assessment. A calculation of the remaining strength of the pipe is not commensurate with the pipeline class location. Predicted metal loss greater than 50% of nominal wall thickness. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
Internal Corrosion	An immediate repair condition as per 192.933(d)(1) Any metal-loss indication affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding.	A calculation of the remaining strength of the pipe shows a defect may grow to an immediate repair condition prior to the next scheduled assessment. A calculation of the remaining strength of the pipe is not commensurate with the pipeline class location.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
	Predicted metal loss greater than 80% of the nominal wall thickness. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Predicted metal loss greater than 50% of nominal wall thickness. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	
Stress Corrosion Cracking (SCC) or other crack like defects	An immediate repair condition as per 192.933(d)(1) A calculation of the remaining strength of the pipe shows a defect may grow to an immediate repair condition prior to the next scheduled assessment. Any indication of significant SCC or significant selective seam weld corrosion (SSWC). A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Evidence of cracks or crack-like defects in the pipe body, longitudinal seam, circumferential or branch-connection welds that are not an immediate condition. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	The pipeline meets the SCC threat criteria per ASME B31.8S Appendix A but no indications of SCC have been found as a result of assessments. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
Manufacturing	An immediate repair condition as per 192.933(d)(1) A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Tooling marks, rolling scabs, or other imperfections from the original pipe fabrication > 10% of the nominal wall thickness An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	Tooling marks, rolling scabs, or other imperfections from the original pipe fabrication ≤ 10% of the nominal wall thickness An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
Welding/Fabrication/Construction	An immediate repair condition as per 192.933(d)(1) or a one-year condition as per 192.933(d)(2) A leaking defect. A dent that has any indication of metal loss, cracking, or a stress riser. An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	A dent that exceeds the criteria established in 192.933 (d) (3) but is not an immediate repair condition or a one-year condition as per 192.933(d)(2) Presence of legacy construction techniques (e.g., miter bends, wrinkle bends, dresser couplings, acetylene welds, puddle welds, or a crease in a field bend). An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	A dent that meets the criteria established in 192.933 (d) (3) An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
Equipment	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii). A leaking defect.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
3rd Party Mechanical Damage	An immediate repair condition as per 192.933(d)(1) or a one-year condition as per 192.933(d)(2) Any metal-loss indication affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding. A dent that has any indication of metal loss, cracking, or a stress riser. Predicted metal loss greater than 80% of the nominal wall thickness. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	A plain dent that exceeds the criteria established in 192.933(d)(3) but in not an immediate repair condition or a one-year condition. A calculation of the remaining strength of the pipe is not commensurate with the pipeline class location. A gouge or groove greater than 12.5% of nominal wall thickness. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	A plain dent that meets the criteria established in 192.933(d (3) Tooling marks, rolling scabs or other imperfections from the original pipe fabrication ≤ 10% of the nominal wall thickness in conjunction with a dent whose depth is > 4% of the nominal pipe diameter. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.

Threat Category	L = 5	L = 3	L = 0.25
Weather/Outside Force	An immediate repair condition as per 192.933(d)(1) A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	An active land slide zone. Line exposed due to erosion and subject to abnormal stresses. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires remediation prior to the next assessment.	An indication or anomaly that in the judgment of the person designated to evaluate the assessment results does not require remediation prior to the next assessment.
Other	Pipeline cannot be assessed for a specific threat or threats with currently available assessment techniques. A leaking defect. An indication or anomaly that in the judgment of the person designated to evaluate the assessment results requires immediate action as per 192.933(d)(iii).	Replacement is more economical than the cost of conducting ongoing assessments. Line must be taken out of service for the pipeline assessment, but it is not possible to take the pipeline out of service or provide a temporary supply to serve the load.	N/A

<u>Consequence of Failure Lookup Table</u>

Class Location	Score
4	1.15
3	1.10
2	1.05
1	1

Risk Matrix

For a segment of pipeline in the same Class Location, the following table may be used.

			Consequence			
			Class 1	Class 2	Class 3	Class 4
			1	**1.05**	**1.1**	**1.15**
Likelihood of Failure	Sum of Likelihood of Failure Scores	**≥ 5**	≥ 5	≥ 5.25	≥ 5.5	≥ 5.75
	Sum of Likelihood of Failure Scores	**4**	4	4.2	4.4	4.6
	Sum of Likelihood of Failure Scores	**3**	3	3.15	3.3	3.45
	Sum of Likelihood of Failure Scores	**≤ 2**	≤ 2	≤ 2.1	≤ 2.2	≤ 2.3
	Sum of Likelihood of Failure Scores	**≤ 1**	≤ 1	≤ 1.05	≤ 1.1	≤ 1.15

High Risk: Risk Score ≥ 5
Medium Risk: 3 ≤ Risk Score < 5
Low Risk: Risk Score < 3

TIMP Quantitative Risk Assessment Scores for 2025

TIMP Transmission Pipeline Assessments
Integrity Assessments Project Risk

Project	Project Location (Service Area)	Pipe Diameter	Pipe Vintage	Years Since Last Assessment	HCA	Risk Scor	Risk Level
Montreal Line N	Rice Street	20/24	1962	6	Yes	4	High
Highbridge Line	Newport	20	2007	6	Yes	4	High

Data Inputs:
- Years since last integrity assessment
- Presence of High Consequence Areas on the line.

Used for decisions on prioritizing integrity assessments.

Risk Score = Likelihood of Failure x Consequence of Failure

TIMP Quantitative Risk Assessment Scores for 2025

Risk Matrix

			Consequence	
			Non-HCA	HCA
			1	**2**
Likelihood of Failure	Last Assessment > 20 years prior or no previous assessment	**4**	4	8
	15 years ≤ Last Assessment < 20 years prior	**3**	3	6
	5 years ≤ Last Assessment < 15 years prior	**2**	2	4
	Last Assessment < 5 years prior	**1**	1	2

High Risk, Risk Score ≥ 4
Medium Risk, 2 ≤ Risk Score < 4
Low Risk, Risk < 1

Risk Category	Project Risk Scores Range	Number of pipelines identified as of December 31, 2023	Percentage
High	Risk Score ≥ 4	5	31%
Medium	2 ≤ Risk Score < 4	7	44%
Low	Risk < 1	4	25%
Total	All	16	

TIMP Quantitative Risk Assessment Scores for 2025

TIMP MAOP Project Risk

Project	Regulation	Project Location (Service Area)	Current Classification	Prior Test	Material	Consequence	Risk Score	Risk Level
TL0205/ Montreal Line	49 CFR 192.619(a)(2)	Multiple	Transmission	2	0.4	4	9.6	High
East County Line Pressure Test	49 CFR 192.619(a)(2)	Multiple	Transmission	2	0.4	4	9.6	High
Regulator Stations	49 CFR 192.619(a)(2)	Multiple	Transmission	2	0.4	4	9.6	High

Data inputs:

- Test Pressure (validated as traceable, verifiable, and complete)
- Material Records (validated as traceable, verifiable, and complete)
- Class Location
- Presence of High Consequence Area (HCA) or Moderate Consequence Area (MCA)
- Grandfathered Pipeline as per 49CFR 192.619(c)

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = Prior Test Score + Material Score

Prior Test Lookup Table

Condition	Prior Test Score
MAOP established in accordance with 192.619(c) "Grandfather Clause"	3
Records necessary to establish the MAOP in accordance with 192.619(a)(2) are not Traceable, Verifiable, and Complete ("TVC")	2
Test Pressure records are satisfactory	0

Material Lookup Table

Condition	Material Score
Pipeline or station contains material not validated	0.4
Pipeline or station material is validated	0

Consequence Lookup Table

TIMP Quantitative Risk Assessment Scores for 2025

Condition	Consequence Score
Contains HCA	4
Class 3 or Class 4, no HCA	3
Class 1 or 2 with MCA	2
Class 1 or 2, no HCA	1

Risk Matrix

			Consequence			
			Class 1 or 2, no HCA	Class 1 or 2 with MCA, no HCA	Class 3 or Class 4, no HCA	Contains HCA
			1	**2**	**3**	**4**
Likelihood of Failure	MAOP established in accordance with 192.619(c) “Grandfather Clause”, Material no validated	**3.4**	3.4	6.8	10.2	13.6
	MAOP established in accordance with 192.619(c) “Grandfather Clause”, Material validated	**3**	3	6	9	12
	Records necessary to establish the MAOP in accordance with 192.619(a)(2) are not TVC, Material not validated	**2.4**	2.4	4.8	7.2	9.6
	Records necessary to establish the MAOP in accordance with 192.619(a)(2) are not TVC, Material validated	**2**	2	4	6	8
	Test Pressure Records Satisfactory; Pipe or Station Material NOT Validated	**0.4**	0.4	0.8	1.2	1.6
	Test Pressure Records Satisfactory; Pipe or Station Material Validated	**0**	0	0	0	0

High Risk: Risk Score ≥ 5
Low Risk: Risk Score < 5
No Risk: Risk Score = 0

TIMP Quantitative Risk Assessment Scores for 2025

Risk Category	Project Risk Scores Range	Number of pipelines identified as of December 31, 2023	Percentage
High	Risk Score ≥ 5	9	22.5%
Low	Risk < 5	10	25%
No Risk	Risk Score = 0	0	0%
Under Evaluation	TBD	21	52.5%
Total	All	40	

TIMP Quantitative Risk Assessment Scores for 2025

TIMP Transmission Casing Renewal Project Risk

Project Name/Location	Size	Likelihood of Failure	Consequence	Risk Score	Risk Level
20 in High Pressure at Pt Douglas & SpringSide	20”	4	4	16	High

Data inputs:

- Indication of a metallic short or electrolytic short between the casing and carrier pipe
- Guided Wave Ultrasonic Testing (“GWUT”) indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area, in accordance with PHMSA Guided Wave UT Go-No Go Procedures (I.e., “18-point checklist”)
- Carrier Pipe diameter, operating pressure and location

Risk Score = Likelihood of Failure x Consequence of Failure

Consequence of Failure = Potential Impact Radius of downstream pipeline (PIR)

$$PIR\ (ft) = .69 * \sqrt{Pressure(psig) * Diameter(in)^2}$$

<u>Likelihood of Failure Lookup Table</u>

Condition	Score
Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short. A leak on the carrier pipe.	4
Indication of an electrolytic contact between the casing and carrier pipe.	3
No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area.	2
Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using the PHMSA Guidelines for Integrity Assessment of Carrier Pipes.	1

<u>Consequence of Failure Lookup Table</u>

Condition	Score
Transmission Carrier Pipe that contains HCA	5
Transmission Carrier Pipe – Class 3 or Class 4; Distribution Main Carrier Pipe – PIR > 100 feet	4
Transmission Carrier Pipe – Class 1 or Class 2; Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	3
Distribution Main Carrier Pipe – PIR ≤ 20 feet	2
Distribution Service Carrier Pipe	1

TIMP Quantitative Risk Assessment Scores for 2025

Risk Metric

			Consequence				
			Distribution Service Carrier Pipe	Distribution Main Carrier Pipe – PIR ≤ 20 ft.	Transmission Carrier Pipe – Class 1 or Class 2 OR Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	Transmission Carrier Pipe – Class 3 or Class 4 OR Distribution Main Carrier Pipe – PIR> 100 ft.	Transmission Carrier Pipe that Contains HCA
			1	**2**	**3**	**4**	**5**
Likelihood of Failure	Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short	**4**	4	8	12	16	20
	Indication of an electrolytic contact between the casing and carrier pipe	**3**	3	6	9	12	15
	No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area	**2**	2	4	6	8	10
	Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using PHMSA Guidelines for Integrity Assessment of Cased Pipe	**1**	1	2	3	4	5

High Risk, Risk Score ≥ 15

Medium Risk, 6 ≤ Risk Score < 15

Low Risk, Risk < 6

Distribution Integrity Management Program and Mandated Relocations Overview and Project Detail

I. DIMP OVERVIEW

Managing the integrity and safe operation of our gas systems is a continuous process. At its core, the Distribution Integrity Management Program (DIMP) can be summarized in three steps:

1) understand your assets,
2) risk evaluation, and
3) risk mitigation.

Our processes for these three steps are outlined below.

The progression of these steps is part of the Company's proactive integrity management program and continually evolves as new information becomes available about the Company's natural gas assets. We incorporate knowledge gained about our assets through normal operations as well as routine maintenance activities, pipeline surveys, inspections, proactive mitigation measures, industry trends, and regulatory guidance or changes to state or federal codes. Using the processes identified below, we are continually updating our DIMP plans and projects to address the ongoing obligation to ensure the safe and reliable operation of our gas distribution system.

1) Understand Your Assets

The overall goal of the Company's integrity programs is to provide safe and reliable service to our customers. For the DIMP to be successful, the Company needs to gather information about gas distribution assets and their operating environments. We collect specific data and information, including paper documents, electronic databases, and the experience of subject matter experts (SMEs).

2) Risk Evaluation

Using the knowledge of our gas distribution assets, we evaluate relative risk based on variables including pipe material, pipe size, prior failures, and failure causes. The Company also considers historical incidents, industry trends, Pipeline

DIMP and Mandatory Relocations Overview

Hazardous Materials Safety Administration (PHMSA) advisory bulletins, regulatory commitments, and knowledge from other distribution operators and industry members. The Company employs a risk assessment methodology to evaluate unwanted consequences and the likelihood of the consequences occurring on the Company's natural gas infrastructure. A probabilistic risk score is assigned and is used as guidance by SMEs, enabling stratification or ranking of projects based on asset characterization and probability of pipe failure. This risk assessment methodology leads to a quantitative risk score and a risk category — high, medium, or low – along with other outputs useful for risk mitigation planning.

The Company evaluates our gas pipelines for the following threats:

- Corrosion,
- Natural forces,
- Excavation damage,
- Other outside force,
- Materials, weld, or joint failure,
- Equipment failure,
- Incorrect operation, and
- Other threats.

The Company also evaluates the historical cause of leaks to gain an understanding of the presence of particular threats to the system.

3) Risk Mitigation

The Company integrates the results from the risk evaluation process into determining planned risk mitigation activities. Using the information gathered and industry best practices, we take appropriate measures to reduce or remove the risks to the distribution system — either by reducing the likelihood or lessening the consequences of a threat or multiple threats. One such measure is the targeted replacement of pipe segments that are poor performing or problematic. Xcel Energy's gas distribution replacement programs have traditionally been material-based, targeted towards removing identified higher risk materials (e.g., cast-iron, bare steel, vintage plastic, etc.). For material families that have noticeably higher risk than other families, this has been a reasonable approach, providing for reasonable optimization of risk reduced per unit of capital invested. Specific programs identified as appropriate measures to reduce risk include:

- Replacement of poor performing coated steel pipelines to address corrosion;
- Renewal of mechanical or compression coupled mains and services to address material and welds concerns and corrosion;
- Renewal of poor performing Aldyl-A (PEA) pipelines, a type of polyethylene pipe material to address material and weld concerns and equipment issues;
- Replacement of copper services and risers to address corrosion;
- Inspecting intermediate pressure (IP) pipelines[1] and repairing or replacing as needed to address corrosion and joint, material, and weld concerns; and
- Replacement of IP pipelines to address corrosion and joint, material and weld concerns.

In continuing risk reduction efforts, as these material-based replacement programs start wrapping up, Xcel Energy has continued to develop strategies to continue to remove risk in the most beneficial and cost-effective ways.

The advent of true quantitative risk assessment methodologies provides a tool for developing such optimized replacement strategies - moving from the material-based approach to a true risk optimized approach. As shown below, this type of approach can be effective in developing optimized replacement strategies for assets outside the common bad actor families (e.g., cast-iron) and even within these families.

No two assets have the exact same risk profiles. Even within asset families, such as cast-iron and bare steel, there is a distribution of risk based on the specifics of each asset and its environment. For example, vintage plastic – which is prone to slow crack growth failures due to rock impingement – installed in areas with rocky soils, in pipelines operating at higher pressures, and in areas with higher ground temperatures, will have higher failure rates than the same vintage plastic pipe installed in areas with sandy soils operating at lower pressures with lower ground temperatures. So, while the materials-based approach provides a gross level of risk ranking, it does not capture the subtleties of the risk distributions within each asset family and across the distribution system.

A true quantitative risk assessment, which assesses the risk for each individual asset based on its specific factors, provides for the ability to accurately rank risk across the entire distribution system and hence provide for a true risk-based prioritization for

[1] Generally defined as lines operating above 60 pounds per square inch gauge and below transmission.

replacement programs. The J-DIMP™ by JANA, Xcel Energy gas distribution risk model does exactly that.

Risk mitigation is not solely focused on pipe replacement programs but can also include preventative measures, performing inspections using specialized technology, or more frequent equipment and pipeline inspections. As part of its comprehensive integrity management program, the Company has identified different risk mitigation strategies, all of which intend to reduce the likelihood or consequences posed by a threat or multiple threats.

II. 2025 DIMP PROJECTS

The Company requests recovery of the following operational and maintenance (O&M) and capital expenditures associated with six 2025 DIMP programs:

2025 Estimated DIMP Project Costs
($ Millions)

Program	2025 Capital	2025 O&M
Poor Performing Mains	$19.53	$0.00
Poor Performing Services	$6.50	$0.53
Intermediate Pressure (IP) Lines Assessments / Replacements	$0.00	$0.28
Sewer and Gas Line Conflict Investigation	$0.00	$1.25
Distribution Valve Replacement	$0.47	$0.00
Casing Renewal	$3.20	$0.00
Total 2025 DIMP Capital Expenditures and O&M	**$29.70**	**$2.06**
Total 2025 Minnesota DIMP Revenue Requirement	**$15.00**	**$1.53**

All of these projects, except for Casing Renewal and Sewer and Gas Line Conflict Investigation, were included in the Company's 2015 through 2024 GUIC Rider petitions.[2] The Casing Renewal project began in 2021, and the Sewer and Gas Line

[2] Docket Nos. G002/M-14-336, G002/M-15-808, G002/M-16-891, G002/M-17-787, G002/M-18-692, G002/M-19-664, G002/M-20-799, G002/M-21-765, G002/M-22-578 and G002/M-23-457.

DIMP and Mandatory Relocations Overview

Conflict Investigation was included in the Company's 2015 through 2018 GUIC Rider petitions. The capital-related cost estimates for 2025 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads. The 2025 project detail for each project is presented in Attachment D1 and the risk assessment scores for 2025 projects are presented in Attachments D2(a) and D2(b). Main and service projects are generally planned six months to one year in advance. Actual construction on identified main projects will generally begin during the 2nd quarter, and assets will typically be in-service during the 3rd and 4th quarters. For example, 2025 project identification typically occurs in the 3rd and 4th quarters of 2024 and 1st quarter of 2025, construction will commence during the 2nd quarter of 2025, and in-servicing will occur during the 3rd and 4th quarters of 2025.

1) Poor Performing Main Replacements
Work Breakdown Structure (WBS):[3] E.0010011.003; E.0010043.019 (Capital)

2025 Estimated Project Costs
$19.53 million Capital expenditure

Project Summary and Scope
The Company's approach for the systematic renewal of poor performing mains allows for optimized resource use and coordination with local communities, reducing the inconvenience of street construction for our customers. The Company is continually evaluating threats on the pipeline system and identifying distribution main segments that pose a risk due to pipe material deterioration or leaks. The selection and prioritization of pipe segments and/or areas targeted for replacement is based on leak history, relative ranking from the risk modeling, deficiencies in coating or cathodic protection, and construction methods, particularly those joined using mechanical couplings. Additional reviews and input from engineers and SMEs are incorporated into the replacement decisions. Replacing main pipeline segments is a multi-year project with the areas identified as higher risk being mitigated earlier in sequence than lower risk areas.

[3] WBS has replaced the parent project number for projects in previous GUIC filings. This switch in numbering is due to a change in our work and asset management system. The previously used parent projects generally correspond with one WBS.

Materials and construction methods are a major contributing factor in poor main performance. For example, mains made from Polyethylene Aldyl-A (PEA)[4] can become brittle over time and are subject to sudden failure from cracking.

The Company has also identified segments of vintage coated steel pipe to be removed due to the mechanical couplings that were used to join the pipe. Many of these mains appear to pose no risk unless they have been disturbed through third-party damage (i.e., excavation damage) or natural forces (i.e., frost heave). Once disturbed, the mechanical couplings can begin to leak, resulting in property damage, outages, and other consequences. The systematic removal of these pipe segments will reduce operating risk and reduce the likelihood of incidents.

As previously described, the Company utilizes a risk assessment process to perform the initial relative ranking of poor performing mains. This list is then reviewed by SMEs, who may adjust the project priorities based on their knowledge. SMEs consist of engineering, cathodic protection, construction, and integrity management employees.

To minimize costs to customers and ensure customer safety and system reliability, main and service renewal projects are designed with consideration of adjacent facilities, municipal requirements, and distribution system operational needs. This includes the viability of dual main installations, which eliminates directional boring associated with installing gas services under roadways. The Company may also convert segments from low-pressure to high-pressure distribution, eliminating the need for additional capital and on-going operating expenses for regulator stations. Additionally, to the extent possible, main and service replacements will be coordinated with city rehabilitation and resurfacing projects to further reduce overall costs and minimize construction impacts on neighborhoods. Both main and service replacements are considered for simultaneous construction to minimize overall costs.

The Company utilizes a sourcing process that results in multi-year, unit cost agreements. Materials are sourced through our standard procurement contracts. Engineering and design are completed in-house using Company employees and contractor staff. Internal labor costs are excluded from the GUIC Rider.

---

[4] PHMSA has issued several advisory bulletins about PEA mains, including PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02.

2) Poor Performing Service Replacements
WBS: E.0010011.004 (Capital)
A.0008610.004.001.001 (O&M)

2025 Estimated Project Costs
$6.50 million Capital expenditure
$0.53 million O&M expenditure

Project Summary and Scope
As with the analysis of poor performing mains, the Company uses the aforementioned risk assessment methodology to provide a relative ranking of problematic service segments. These problematic segments are then reviewed by SMEs, who may adjust project priorities based on their knowledge. SMEs consist of engineering, cathodic protection, construction, and integrity management employees. This is a multi-year program with the areas identified as higher risk, as measured by leak ratios and other factors, being mitigated in the appropriate order. Where pertinent, service replacements are considered for simultaneous construction along with main replacements to minimize construction costs.

3) IP Line Assessments
WBS: E.0000007.053(Capital); A.0008610.004.001.005 (O&M)

2025 Estimated Project Costs
$0.00 million Capital expenditure
$0.28 million O&M expenditure

Project Summary and Scope
This is an ongoing project to assess and renew IP lines. Selection of assessment methodologies and pipeline segments for inspection is based on an evaluation of the critical IP lines in the distribution system, and an evaluation of elements of specific DIMP threats. The IP system is comprised of steel pipe susceptible to the threats from corrosion, manufacturing defects,[5] construction methods,[6] and third-party damage. The consequences associated with a failure of these pipelines are heightened due to the higher operating pressures and the location of many of these

[5] Material defects, long seam defects.
[6] Compression couplings and welds.

lines in heavily developed areas. For IP lines, direct assessment is the primary assessment methodology. However, pressure testing may also be utilized based on the applicable threats and the ability to take the pipeline out of service.

The Company plans on conducting between two and five IP line assessments per year. The Company maintains a prioritized list of anomalies identified through indirect inspections and verification digs that will be completed on these anomalies, as applicable. O&M budgets for this program are volatile depending on the condition of the pipelines assessed and the number of anomalies identified for excavation and repair.

This project includes health and condition assessments on IP lines. In 2025, the Company plans to conduct integrity assessments including follow up excavations on one pipeline and indirect surveys on three pipelines to identify any potential threats of corrosion and repair any corrosion defects. Lastly, the Company is assessing sixteen river crossings using underwater divers to identify any potential threat from natural forces due to changing river flows and currents. The IP Line Assessment work in 2025 includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Multiple River Crossings	Underwater Assessment	N/A	O&M
Colby Lake Lateral	Indirect Survey	3.6	O&M
East County Line A	Indirect Survey	3.6	O&M
Langdon Line	Indirect Survey	9.2	O&M
Follow Up Digs	Follow Up Digs	Various	O&M

- **River Crossing Assessments:** This project includes using underwater divers to inspect for pipeline damage from debris at the bottom of the river and to assure that cover over the pipeline remains adequate due to changing riverbed depths from silt deposit changes. A total of 16 crossings will be assessed ranging in size from 2-inch to 6-inch. Mitigation of anomalies will depend on the condition of the pipelines assessed and changes to river bottom depths identified.

- **Indirect Survey:**
    - Colby Lake Lateral: This project covers 3.6 miles of high-pressure distribution pipe near Woodbury, MN. This segment will be assessed using an indirect survey.
    - East County Line A: This project covers 3.6 miles of high-pressure distribution pipe near Newport, MN. This segment will be assessed using an indirect survey.
    - Langdon Line: This project covers 9.2 miles of high-pressure distribution pipe near Newport, MN. This segment will be assessed using an indirect survey.

- **Follow Up Digs:**

  Follow up excavations based on survey results from 2024 work will occur in 2025.

4) Sewer and Gas Line Conflict Investigation
WBS: A.0008610.004.001.006 (O&M)

2025 Estimated Project Costs
$0.00 million Capital expenditure
$1.25 million O&M expenditure

Project Summary and Scope
In 2010, the Company at the request of the Minnesota Public Utilities Commission (MPUC) and PHMSA, developed and implemented safety plans to reduce the risk to customers and minimize the threat of future cross bores. The Company focused on, in particular, PHMSA's Gas Distribution Pipeline Integrity Management Enforcement Guidance 3 which notes, "Cross bores of gas lines in sewers have been reported at 2-3 per mile in high-risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in proximity of each other. As such, operators must determine the potential for cross bore of sewers resulting in gas lines intersecting with sewers."

The Company has been inspecting sewer laterals and mains since 2010 and has incorporated a post construction clearing as a requirement prior to in-servicing any newly installed main or service. Sewer clearing efforts over the last few years have been primarily focused on the Company's "Call before you clear" program and post construction camera work. As a result of knowledge sharing with industry partners and the identification of new risk factors significant to identifying potential sewer and gas line conflict locations, the Company plans to increase legacy clearing efforts in high-risk locations. The current plan estimates that approximately 3,500 services will be inspected for conflicts in 2025 as a part of legacy inspections.

5) Distribution Valve Replacement Project
WBS: E.0010011.005 (Capital)

2025 Estimated Project Costs
$0.47 million Capital expenditure

Project Summary and Scope
The placement, accessibility, and functionality of valves in the gas distribution system are critical components of gas operations, as valves provide the ability to isolate sections of the system in the event of an emergency or incident. By isolating sections during these events, the public can be better protected, and customer impacts can be minimized.

The Company has identified a need to add, replace, or otherwise rehabilitate existing distribution valves. As a result of DIMP regulations, the Company is focusing directly on valve conditions and locations when determining valves that should be replaced or installed. This work is in response to the Company's obligation under Code 49 CFR Part 192.1007(d).

A review of existing valve isolation areas has identified the need for adding 31 new valves to reduce the time to shut down a section of main in an emergency. These valves range in size from 2-inch to 12-inch and will be installed throughout the service areas. Of these new valves, 24 are expected to be installed in 2025 with the remaining seven to be installed in 2026-2029.

In addition to new valve installations, the program will replace existing distribution system isolation valves which have become inaccessible, inoperable or are beyond their useful life.

Additional valves have been identified as inoperable while performing periodic maintenance and operating procedures. The Company currently estimates a total of 30 distribution valves will be replaced in the South Metro and Southeast areas. These valves range in size from 2-inch to 16-inch. Of these valves, six are expected to be replaced in 2025 with the remaining to be replaced in 2026-2029. Replacing these valves will allow the Company more options to isolate sections to address an emergency or system incident, while impacting the smallest number of customers.

The 2025 scope of work includes the following valves:

Distribution Valve Location	Valve #	Size / Material
Frank St & Burns (Southside), St Paul (NPT Area)	EV1228	12" Steel
Prior Ave & Milwaukee RR Tracks (Southside), St Paul	EV1332	8" Steel
Roselawn & Fairview (60# side), Roseville	EV1440	8" Steel
Dodd Rd & Willow Ln (Eastside), Mendota Heights	DV3781	3" PE
Western Ave N & Front Ave (Northside), St Paul	DV3342	6" Steel
Thompson Ave & 19th Ave N, South St Paul	DV1544	3" PE

6) Casing Renewal Project
WBS: E.0010011.012 (Capital)

<u>2025 Estimated Project Costs</u>
$3.20 million Capital expenditure

<u>Project Summary and Scope</u>
Casings were routinely installed for a variety of situations including under roads and railroads. Pipelines were installed inside the casings to protect the pipe from a variety of forces. Improved design has mostly eliminated the use of casings in modern gas construction. In several instances, the Company cannot determine if the pipeline carrying gas is isolated from the casing, a situation that can create a corrosion risk and lead to pipeline failure.
The objective of this project is to mitigate the risk by renewing the pipeline or installing equipment that allows ongoing testing to ensure isolation.

The ability to test for isolation is in accordance with the Company's Gas Standards Manual section 9.9.9 and 49 CFR § 192.467 which provide that for all metallic carrier pipe installed in a metallic casing, the Company shall take pipe-to-soil and casing-to-soil readings annually with the purpose of determining whether the two pieces of pipe are in contact (shorted). The Company assumes all casings that cannot be tested for isolation between the carrier pipe and the casing are shorted (electrically continuous) until test leads can be installed and tested. If testing shows the pipe and casing are isolated, the casing is added to the annual test lead survey and will be monitored and maintained over time. If testing shows no isolation (shorted), the casing will be renewed under this project. Some casings were installed when road right of way (ROW) was narrower and casings were not extended when the road was widened. In these cases, the Company renews the carrier pipe and eliminates the casing, thus removing the corrosion risk.

This project began in 2021 and will continue annually until all casing risks on the program list have been mitigated.

The Company currently has 20 distribution casings remaining to be renewed in the East Metro, Southeast and Northwest areas. Of these casings, five are expected to be renewed in 2025 with the remaining casings being renewed in 2026-2029.

The 2025 scope of work includes the following casings:

Casing Location	Pipe Size	Leaking	Shorted
Renew intersection at Wabash & Vandalia (12in, 8in, 4in)	6”	N	Y
12in main at W 5th St & East Ave	12”	N	N
16in on University Ave.	16”	N	N
RR Crossing at Fairview and County Rd C	4”	N	Y
Gervais Ave & HWY 61, Maplewood	6”	N	Y

III. 2024 DIMP PROJECTS

There are 5 projects under the DIMP in 2024. The following are the DIMP project costs originally included in the Company's 2024 GUIC Rider Petition,[7] as compared to revised 2024 cost estimates[8] based on current-year project developments and actual construction activity:

2024 Estimated DIMP Project Costs
($ Millions)

Program	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Poor Performing Mains	$19.14	$19.97	$0.83	4.34%	$0.00	$0.00	$0.00	0.00%
Poor Performing Services	$6.37	$3.94	($2.43)	-38.15%	$0.00	$0.40	$0.40	-
Intermediate Pressure (IP) Lines Assessments	$0.00	$1.32	$1.32	-	$0.29	$0.22	($0.07)	-24.1%
Sewer and Gas Line Conflict Investigation	$0.00	$0.00	-	-	$0.10	$0.20	$0.10	95%
Distribution Valve Replacement	$0.42	$0.45	$0.03	7.14%	$0.00	$0.00	$0.00	-
Casing Renewal	$2.67	$2.87	$0.20	7.49%	$0.00	$0.00	$0.00	-
Total 2024 DIMP Capital Expenditures and O&M	**$28.60**	**$28.54**	**($0.05)**	**-0.17%**	**$0.39**	**$0.81**	**$0.42**	**107.7%**
Total 2024 MN DIMP Revenue Requirement	**$10.07**	**$11.25**	**$1.18**	**11.68%**	**$0.39**	**$0.41**	**$0.02**	**5.8%**

The capital-related cost estimates for 2024 exclude internal labor and include materials, outside services, transportation, and the portion of construction overheads not related to internal labor. The 2024 project details for each project are presented in Attachment D1.

[7] Docket No. G002/M-23-457.
[8] Based on actual costs as of 6/30/2024 and estimates from 7/1/2024 through 12/31/2024.

DIMP and Mandatory Relocations Overview

1) Poor Performing Main Replacements
WBS: E.0010011.003, E.0010043.019, E.0010038.070 (Capital)

Project Summary and Scope

The Company's approach for the systematic renewal of poor performing mains allows for optimized resource use and coordination with local communities, reducing the inconvenience of street construction for our customers. The Company is continually evaluating threats on the pipeline system and identifying distribution main segments that pose a risk due to pipe material deterioration or leaks. The selection and prioritization of pipe segments and/or areas targeted for replacement is based on leak history, relative ranking from the risk modeling, deficiencies in coating or cathodic protection, and construction methods, particularly those joined using mechanical couplings. Additional reviews and input from engineers and SMEs are incorporated into the replacement decisions. Replacing main pipeline segments is a multi-year project with the areas identified as higher risk being mitigated earlier in sequence than lower risk areas.

Materials and construction methods are a major contributing factor in poor main performance. For example, mains made from Polyethylene Aldyl-A (PEA)[9] can become brittle over time and are subject to sudden failure from cracking.

The Company has also identified segments of vintage coated steel pipe to be removed due to the mechanical couplings that were used to join the pipe. Many of these mains appear to pose no risk unless they have been disturbed through third-party damage (i.e., excavation damage) or natural forces (i.e., frost heave). Once disturbed, the mechanical couplings can begin to leak, resulting in property damage, outages, and other consequences. The systematic removal of these pipe segments will reduce operating risk and reduce the likelihood of incidents.

As previously described, the Company utilizes a risk assessment process to perform the initial relative ranking of poor performing mains. This list is then reviewed by SMEs, who may adjust the project priorities based on their knowledge. SMEs consist of engineering, cathodic protection, construction, and integrity management employees.

[9] PHMSA has issued several advisory bulletins about PEA mains, including PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB 08-02.

DIMP and Mandatory Relocations Overview

To minimize costs to customers and ensure customer safety and system reliability, main and service renewal projects are designed with consideration of adjacent facilities, municipal requirements, and distribution system operational needs. This includes the viability of dual main installations, which eliminates directional boring associated with installing gas services under roadways. The Company may also convert segments from low-pressure to high-pressure distribution, eliminating the need for additional capital and on-going operating expenses for regulator stations. Additionally, to the extent possible, main and service replacements will be coordinated with city rehabilitation and resurfacing projects to further reduce overall costs and minimize construction impacts on neighborhoods. Both main and service replacements are considered for simultaneous construction to minimize overall costs.

The Company utilizes a sourcing process that results in multi-year, unit cost agreements. Materials are sourced through our standard procurement contracts. Engineering and design are completed in-house using Company employees and contractor staff. Internal labor costs are excluded from the GUIC Rider.

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$19.14	$19.97	$0.83	4.34%	$0.00	$0.00	$0.00	-

Variance Explanation

Capital: The variance is primarily due to more main renewal work than anticipated and unexpected soil mitigation and higher than anticipated mechanical construction costs associated with the Old Hwy 8 main renewal project.

O&M: None.

DIMP and Mandatory Relocations Overview

2) Poor Performing Service Replacements
WBS: E.0010011.004 (Capital)
A.0008610.004.001.001 (O&M)

Project Summary and Scope
As with the analysis of poor performing mains, the Company uses the aforementioned risk assessment methodology to provide a relative ranking of problematic service segments. These problematic segments are then reviewed by SMEs, who may adjust project priorities based on their knowledge. SMEs consist of engineering, cathodic protection, construction, and integrity management employees. This is a multi-year program with the areas identified as higher risk, as measured by leak ratios and other factors, being mitigated in the appropriate order. Where pertinent, service replacements are considered for simultaneous construction along with main replacements to minimize construction costs.

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$6.37	$3.94	($2.43)	-38.15%	$0.00	$0.40	$0.40	107.7%

Variance Explanation

Capital: The variance is primarily due to less service renewal work relative to main renewal work.

O&M: None.

3) IP Line Assessments
WBS: E.0000007.053, E.0000043.001, E.0000045.001, E.0010033.034, E.0010075.051, E.0010075.067, E.0000146.001 (Capital); A.0008610.004.001.005 (O&M)

Project Summary and Scope

This is an ongoing project to assess and renew IP lines. Selection of assessment methodologies and pipeline segments for inspection is based on an evaluation of the critical IP lines in the distribution system, and an evaluation of elements of specific DIMP threats. The IP system is comprised of steel pipe susceptible to the threats from corrosion, manufacturing defects,[10] construction methods,[11] and third-party damage. The consequences associated with a failure of these pipelines are heightened due to the higher operating pressures and the location of many of these lines in heavily developed areas. For IP lines, direct assessment is the primary assessment methodology. However, pressure testing may also be utilized based on the applicable threats and the ability to take the pipeline out of service.

The Company plans on conducting between two and five IP line assessments per year. The Company maintains a prioritized list of anomalies identified through indirect inspections and verification digs will be completed on these anomalies, as applicable. O&M budgets for this program are volatile depending on the condition of the pipelines assessed and the number of anomalies identified for excavation and repair.

This project includes health and condition assessments on IP lines. In 2024, the Company plans to conduct integrity assessments including follow up excavations on one pipeline and indirect surveys on five pipelines to identify any potential threats of corrosion and repair any corrosion defects. Lastly, the Company is assessing 14 river crossings using underwater divers to identify any potential threat from natural forces due to changing river flows and currents.

[10] Material defects, long seam defects.
[11] Compression couplings and welds.

The IP Line Assessment work in 2024 includes the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Multiple River Crossings	Underwater Assessment	N/A	O&M
R5000 Lateral	Indirect Survey	2.8	O&M
Faribault Feeder Line	Indirect Survey	1.0	O&M
St Bonifacius Lateral	Indirect Survey	7.2	O&M
Babcock Lateral	Indirect Survey	0.5	O&M
Conway Lateral	Indirect Survey	0.7	O&M
Kwik Trip Lateral	Follow Up Digs	Various	O&M
County Road B – Rice to Hamline	Replacement	3.4	Capital
BRD/Nisswa/Co Rd 13	Replacement	0.5	Capital

- **River Crossing Assessments:** This project includes using underwater divers to inspect for pipeline damage from debris at the bottom of the river and to assure that cover over the pipeline remains adequate due to changing riverbed depths from silt deposit changes. A total of 14 crossings will be assessed ranging in size from 6-inch to 20-inch in the communities of St. Paul and Newport. Mitigation of anomalies will depend on the condition of the pipelines assessed and changes to river bottom depths identified.

- **Indirect Survey:**
  - R5000 Lateral: This project covers 2.8 miles of high-pressure distribution pipe near Winona, MN. This segment was assessed using indirect survey.
  - Faribault Feed Line: This project covers 1.0 mile of high-pressure distribution pipe near Faribault, MN. This segment was assessed using indirect survey.

- <u>St. Bonifacius Lateral:</u> This project covers 7.2 miles of high-pressure distribution pipe near St. Bonifacius, MN. This segment was assessed using indirect survey.
- <u>Babcock Lateral:</u> This project covers 0.5 miles of high-pressure distribution pipe near Sunfish Lake, MN. This segment was assessed using indirect survey.
- <u>Conway Lateral:</u> This project covers 0.7 miles of high-pressure distribution pipe near Maplewood, MN. This segment was assessed using indirect survey.

- **Follow Up Digs:**
  - <u>Kwik Trip Lateral:</u> Follow up excavations were not completed on the Kwik trip lateral in 2024. It was determined that an integrity dig was required at R443 that was completed instead.
  - <u>R443 Integrity Dig:</u> Follow up excavation based on concerns from local operations work occurred in 2024.

- **<u>County Road B – Rice to Hamline:</u>** This project is along County Road B in Roseville, MN and entails replacing 3.4 miles of 16-inch, and 12-inch pipe with a standardized 16-inch pipe. This pipeline was originally installed in the 1950s with service lines directly connected to it, multi diameter piping and mechanical couplings. Replacement with a new single diameter will eliminate poor performance, unknown construction specifications and establish MAOP. This was originally identified as a three-year project with engineering and permitting completed in 2020, and construction wrapping up in 2022. However, due to material constraints and construction running into the first snow fall in 2022, some final construction and restoration activities continued into 2023. Due to sourcing material delays, the fence was not installed until January 2024. Additionally, due to internal sourcing challenges, the RCV work at Rose & Hamline was not completed until spring of 2024. The RCV programming work at Rice & B and at Henry & B will be completed in 2024.

- **<u>BRD/Nisswa/Co Rd 13:</u>** This project is along Country Road 13 in Nisswa, MN and entails replacing approximately 2,500 feet of a 6-inch pipe. This pipeline was identified as bare steel through direct examination in 2021. This project was postponed due to the identification of an exposed section of high pressure main at a water crossing near Watab, MN. Due to the adequate cathodic protection observed on this line (Nisswa) the water crossing exposure

DIMP and Mandatory Relocations Overview

was deemed to have a higher immediate risk to pipe integrity and was chosen to proceed in 2023. This project proceeded in 2024.

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.00	$1.32	$1.32	-	$0.29	$0.22	($0.07)	-24.1%

Variance Explanation

Capital: The increase is primarily due to the inclusion of the BRD/Nisswa/Co Rd 13 in the 2024 plan. Additionally, sourcing delays on the County Road B project delayed some final work to 2024.

O&M: None.

4) **Sewer and Gas Line Conflict Investigation**
WBS: A.0008610.004.001.006 (O&M)

Project Summary and Scope
In 2010, the Company at the request of the Minnesota Public Utilities Commission (MPUC) and PHMSA, developed and implemented safety plans to reduce the risk to customers and minimize the threat of future cross bores. The Company focused on, in particular, PHMSA's Gas Distribution Pipeline Integrity Management Enforcement Guidance 3 notes, "Cross bores of gas lines in sewers have been reported at 2-3 per mile in high-risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in proximity of each other. As such, operators must determine the potential for cross bore of sewers resulting in gas lines intersecting with sewers."

The Company has been inspecting sewer laterals and mains since 2010 and has incorporated a post construction clearing as a requirement prior to in-servicing any newly installed main or service. Sewer clearing efforts over the last few years have been primarily focused on the Company's "Call before you clear" program and post construction camera work. As a result of knowledge sharing with industry partners and the identification of new risk factors significant to identifying potential sewer and gas line conflict locations, the Company plans to revitalize legacy clearing efforts in high-risk locations.

The current plan estimates that approximately 1,900 services will be inspected for conflicts in 2024 as a part of legacy inspections. The Company will continue to monitor circumstances that may indicate a need to accelerate legacy inspections.

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.00	$0.00	$0.00	-	$0.10	$0.20	$0.10	95%

Variance Explanation

Capital: None.

O&M: None.

5) Distribution Valve Replacement Project
WBS: E.0010011.005 (Capital)

Project Summary and Scope
The placement, accessibility, and functionality of valves in the gas distribution system are critical components of gas operations, as valves provide the ability to isolate sections of the system in the event of an emergency or incident. By isolating sections during these events, the public can be better protected, and customer impacts can be minimized.

The Company has identified a need to add, replace, or otherwise rehabilitate existing distribution valves. As a result of DIMP regulations, the Company is focusing directly on valve conditions and locations when determining valves that should be replaced or installed. This work is in response to the Company's obligation under Code 49 CFR Part 192.1007(d).

A review of existing valve isolation areas has identified the need for adding 40 new valves to reduce the time it takes to shut down a section of main in an emergency. These valves range in size from 2-inch to 12-inch and will be installed throughout the service area. Of these new valves, nine are expected to be installed in 2024 with the remaining 31 to be installed in 2025-2029.

In addition to new valve installations, the program will replace existing distribution system isolation valves which have become inaccessible, inoperable or are beyond their useful life.

As noted in the 2022 GUIC Rider Filing, the Company anticipated concluding this project in 2019. However, additional valves have been identified as inoperable while performing periodic maintenance and operating procedures. The Company currently estimates a total of 30 distribution valves will be replaced in the South Metro and Southeast areas. These valves range in size from 2-inch to 16-inch. Of these valves, 11 are expected to be replaced in 2024 with the remaining to be replaced in 2025-2029. Replacing these valves will allow the Company more options to isolate sections to address an emergency or system incident, while impacting the smallest number of customers.

The 2024 scope of work includes the following valves:

Distribution Valve Location	Valve #	Size / Material
Fairview Ave and Eleanor Ave	EV1034	16" Steel
11th St & 14th St, St Cloud	EV6203	12" Steel
Western Ave N & Co Rd C W (Southside), Roseville	DV6434	8" Steel
Saint Clair & Fairview (West of Intersection), St Paul	EV1603	4" Steel
Victoria (between Minnehaha & Lafond), St Paul	EV1067	6" Steel
Summit & St. Albans St, St. Paul	EV1088	6" Steel
Maryland and St Albans St, St Paul	EV1079	8" Steel
Holloway and McKnight, Maplewood R278	EV1283	3" Steel
80th St & 79th St (Southeast of Intersection), Cottage Grove	EV4734	4" PE
Dewey St & Roblyn Ave STP	EV1330	16" Steel
Woodbury Dr & Valley Creek Rd (Southwest Corner), Woodbury	DV4696	4" Steel

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$0.42	$0.45	$0.03	7.14%	$0.00	$0.00	$0.00	-

Variance Explanation

Capital: None.

O&M: None.

6) Casing Renewal Project
WBS: E.0010011.012 (Capital)

Project Summary and Scope
Casings were routinely installed for a variety of situations including under roads and railroads. Pipelines were installed inside the casings to protect the pipe from a variety of forces. Improved design has mostly eliminated the use of casings in modern gas construction. In several instances, the Company cannot determine if the pipeline carrying gas is isolated from the casing, a situation that can create a corrosion risk and lead to pipeline failure. The objective of this project is to mitigate the risk by renewing the pipeline or installing equipment that allows ongoing testing to ensure isolation.

The ability to test for isolation is in accordance with the Company's Gas Standards Manual section 9.9.9 and 49 CFR § 192.467 which provide that for all metallic carrier pipe installed in a metallic casing, the Company shall take pipe-to-soil and casing-to-soil readings annually with the purpose of determining whether the two pieces of pipe are in contact (shorted).

The Company assumes all casings that cannot be tested for isolation between the carrier pipe and the casing are shorted (electrically continuous) until test leads can be installed and tested. If testing shows the pipe and casing are isolated, the casing is added to the annual test lead survey and will be monitored and maintained over time. If testing shows no isolation (shorted), the casing will be renewed under this project. Some casings were installed when road right of way (ROW) was narrower and casings were not extended when the road was widened. In these cases, the Company renews the carrier pipe and eliminates the casing, thus removing the corrosion risk.

This project began in 2021 and will continue annually until all casings risks on the program list have been mitigated.

The Company currently has 23 distribution casings remaining to be renewed in the East Metro, Southeast and Northwest areas. Of these casings, two are expected to be renewed in 2024 with the remaining casings being renewed in 2025-2029.

The 2024 scope of work includes the following casings:

Casing Location	Pipe Size	Leaking	Shorted
Casing under RR tracks 400' E of Rice St. at entrance to 1900 Rice St. (St. Paul Water) *	4"	N	Y
12in Bore across I-35E at Arlington	12"	N	Y

Projects denoted with an asterisk (*) above were originally planned for renewal in 2021. Due to these projects requiring railroad permits and potential easements, construction was moved to 2024.

2024 Estimated Project Costs
($ Millions)

	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance	2024 O&M, As Filed	2024 O&M Estimates	Variance	% O&M Variance
Capital / O&M Expenditures	$2.67	$2.87	$0.20	7.49%	$0.00	$0.00	$0.00	-

<u>Variance Explanation</u>

Capital: None.

O&M: None.

IV. 2023 DIMP PROJECTS

There were five projects under the DIMP in 2023. The following are the DIMP project costs originally included in the Company's 2023 GUIC Rider Petition,[12] as compared to actual 2023 costs.

2023 Actual DIMP Project Costs
($ Millions)

Program	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Poor Performing Mains	$18.87	$26.16	$7.29	38.63%	$0.00	$0.00	$0.00	-
Poor Performing Services	$6.18	$3.08	($3.10)	-50.11%	$0.00	$0.70	$0.70	-
Intermediate Pressure (IP) Lines Assessments	$1.69	$2.24	$0.55	32.68%	$0.25	$0.25	$0.00	-1.62%
Distribution Valve Replacement	$0.37	$0.51	$0.14	38.73%	$0.00	$0.00	$0.00	0.00%
Casing Renewal	$1.67	$0.33	($1.34)	-80.17%	$0.00	$0.00	$0.00	0.00%
Total 2023 DIMP Capital Expenditures and O&M	**$28.48**	**$32.33**	**$3.85**	**13.52%**	**$0.25**	**$0.95**	**$0.70**	**280%**
Total 2023 MN DIMP Revenue Requirement	**$25.97**	**$18.87**	**($7.10)**	**(27.33%)**	**$0.25**	**$0.25**	**$0.00**	**0.00%**

The capital-related cost estimates for 2023 exclude internal labor and include only materials, outside services, transportation, and the portion of construction overheads not related to internal labor. The 2023 project detail for each project is presented in Attachment D1.

[12] Docket No. G002/M-23-457.

1) Poor Performing Main Replacements
WBS: E.0010011.003, E.0010043.019, E.0010038.070 (Capital)

Project Summary and Scope

For 2023, the poor performing mains materials primarily included PEA and vintage coated steel.

- **Old Hwy 8:** The City of New Brighton had plans to re-do a portion of Old Highway 8 as part of a city-wide improvement program. The Company coordinated with the city in an effort to minimize disruption and to replace about 1.1 miles of 3-inch, 4-inch, and 8-inch pipe with standardized 8-inch plastic pipe. The replaced pipe includes steel main installed in the 1950s and Aldyl-A pipe installed in the early 1970s. Additionally, the Company replaced about 2,600' of 8" old medium-risk pipe with about 2,600' of 12" HP pipe to alleviate the risk and increase capacity for future growth. This project was completed in 2023.

**2023 Actual Project Costs
($ Millions)**

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$18.87	$26.16	$7.29	38.63%	$0.00	$0.00	$0.00	-

Variance Explanation

Capital: The variance is primarily due to more main renewal work than anticipated and unexpected soil mitigation and higher than anticipated mechanical construction costs associated with the Old Hwy 8 main renewal project.

O&M: None.

2) Poor Performing Service Replacements
WBS: E.0010011.004 (Capital)
A.0008610.004.001.001 (O&M)

Project Summary and Scope

For 2023, the primary service-related material types will primarily include PEA and vintage coated steel. Additional material types are included as necessary based on their overall risks.

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$6.18	$3.08	($3.10)	-50.11%	$0.00	$0.70	$0.70	-

Variance Explanation

Capital: The variance is primarily due to less service renewal work relative to main renewal work. Services did not need to be renewed if existing PE services pipe existed; resulting in many services being transferred.

O&M: None.

3) IP Line Assessments
WBS: E.0000043.001, E.0010075.051, E.0000045.001, (Capital);
A.0008610.004.001.005 (O&M)

Project Summary and Scope

This project included health and condition assessments on IP lines. In 2023, the Company continued construction activities on four replacement projects that support the integrity management of the Company's high-pressure distribution pipelines. In addition, the Company conducted integrity assessments including follow up excavations on one pipeline and indirect surveys on two pipelines to identify any potential threats of corrosion and repair any corrosion defects, and an alternating current interference study on one pipeline to identify any potential threats of AC corrosion, AC interference, and hazards to Company personnel. Lastly, the Company assessed 13 river crossings using underwater divers to identify any potential threat from natural forces due to changing river flows and currents. The IP Line Assessment work in 2023 included the following lines:

Line/Loop	Type	Project Length (mi)	Project Type
Hugo Lateral	AC Mitigation	11.2	O&M
Winona Support Line	Follow Up Digs	Various	O&M
Rice Royalton A	Follow Up Digs	Various	O&M
Rice Royalton B and C	Indirect Survey	4.2	O&M
Kwik Trip Lateral	Indirect Survey	3.8	O&M
County Road B – Rice to Hamline	Replacement	3.4	Capital
Langdon Line – TBS to 1st St in St. Paul Park	Replacement	5.8	Capital
BRD/Nisswa/Co Rd 13	Replacement	0.5	Capital (Deferred)
Watab River Exposure	Replacement	0.2	Capital
East County Line MAOP	Replacement	0.2	Capital

- **<u>AC Mitigation:</u>** This project included the installation of any AC mitigation proposed by the study completed in 2022. No immediate need for mitigation was identified through field work, and it was recommended that the Company continue to monitor the pipeline for any changes in AC pipe-to-soil potentials in the future.

DIMP and Mandatory Relocations Overview

- **Follow Up Digs:**
  - Winona Support Line: No follow up excavations were completed based on survey results from 2022. Additional testing was completed in 2023 within Winona TBS to determine cathodic protection continuity.
  - Rice Royalton A: One follow up excavation based on survey results from 2022 work occurred in 2023.

- **Indirect Survey:**
  - Rice Royalton B and C: This project covers 4.2 miles of high-pressure distribution pipe near Watab, MN. This segment was assessed using an ECDA like methodology.
  - Kwik Trip Lateral: This project covers 3.8 miles of high-pressure distribution pipe near Inver Grove Heights, MN. This segment was assessed using an ECDA like methodology.

- **County Road B – Rice to Hamline:** This project is along County Road B in Roseville, MN and entails replacing 3.4 miles of 16-inch, and 12-inch pipe with a standardized 16-inch pipe. This pipeline was originally installed in the 1950s with service lines directly connected to it, multi diameter piping and mechanical couplings. Replacement with a new single diameter will eliminate poor performance, unknown construction specifications and establish MAOP. This was originally identified as a three-year project with engineering and permitting completed in 2020, and construction wrapping up in 2022. However, due to material constraints and construction running into the first snow fall in 2022, some final construction and restoration activities continued into 2023. Due to sourcing material delays, the fence was not installed until January 2024. Additionally, due to internal sourcing challenges, the RCV work at Rose & Hamline was not completed until spring of 2024. The RCV programming work at Rice & B and at Henry & B will be completed in 2024.

- **Langdon Line – TBS to 1st St in St. Paul Park:** This project was along Hwy 61 in Cottage Grove and along Hastings Avenue in St. Paul Park, MN and entailed replacing 5.8 miles of 12-inch, 8-inch and 6-inch pipe with a standardized 12-inch pipe. This pipeline was originally installed in 1958 using multi diameter piping and mechanical couplings. Replacement with a new single diameter will eliminate poor performance, unknown construction specifications and establish MAOP. This was a three-year project with

DIMP and Mandatory Relocations Overview

engineering and permitting completed in 2020, and construction in 2021 and 2022. However, final engineering project close-out activities continued into 2023. No additional work was needed in 2024. Project is complete.

- **BRD/Nisswa/Co Rd 13:** This project is along Country Road 13 in Nisswa, MN and entails replacing approximately 2,500 feet of a 6-inch pipe. This pipeline was identified as bare steel through direct examination in 2021. This project was postponed due to the identification of an exposed section of high pressure main at a water crossing near Watab, MN. Due to the adequate cathodic protection observed on this line (Nisswa) the water crossing exposure was deemed to have a higher immediate risk to pipe integrity and was chosen to proceed in 2023. The Company will continue to monitor the Nisswa bore in the interim until replacement can be revisited.

- **Watab Exposed Pipe:** This project is along Highway 10 at the Little Rock Lake water crossing near Watab, MN and entails replacing approximately 1000 feet of 4-inch pipe. This pipeline was identified from the IP underwater surveys completed in 2022 where approximately 50 feet of the Rice Royalton A line was found to be exposed underwater. No immediate risks to pipe structural integrity were identified at the time but efforts were immediately taken to minimize potential third-party strikes within the body of water. Through conversations with the MN DNR, it was determined that the best path forward to minimize impact to the ecosystem of the body of water would be to abandon the crossing and rebore a new section of main deeper under the water crossing. This is a one-year project with engineering, permitting, and construction being completed in 2023. Final restoration activities may continue into 2024.

- **East County Line/MAOP:** This project involved the installation of a regulator station and approximately 1,000 LF of 2" and 4" pipe. There were two single cut taps to service two different services on the existing 24" main that was replaced as part of the TIMP work. During the 24" main replacement, it was determined that an updated regulator station should be installed. Main installation was needed due to the distance between the two services.

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$1.69	$2.24	$0.55	32.68%	$0.25	$0.25	$0.00	0.00%

Variance Explanation

Capital: The increase is primarily due to the county requiring additional asphalt restoration associated with County Rd B, emerging Watab IP Line project, and the distribution reg station on the East County Line (East segment).

O&M: None.

4) Distribution Valve Replacement Project
WBS: E.0010011.005 (Capital)

Project Summary and Scope
In 2023, the Company installed 18 new valves ranging in size from 2-inch to 12-inch. In addition, six inoperable emergency distribution valves ranging in size from 2-inch to 16-inch steel have been replaced. These valve projects occurred in the South Metro area.

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.37	$0.51	$0.14	38.73%	$0.00	$0.00	$0.00	-

Variance Explanation

Capital: None.

O&M: None.

5) Casing Renewal Project WBS: E.0010011.012 (Capital)

Project Summary and Scope

This project began in 2021 and shall continue annually until all casings risks on the program list have been mitigated.

The Company currently has 23 distribution casings remaining to be renewed in the East Metro, Southeast and Northwest areas. One casing was carried over from 2022 and completed the restoration in 2023. The remaining casings are being renewed in 2024-2027.

The 2023 scope of work included the following casings:

Casing Location	Pipe Size	Leaking	Shorted
Bore Hwy 36 & Rice St.*	12”	N	Y

Projects denoted with an asterisk (*) above were originally constructed in 2022. The final restoration was completed in 2023.

2023 Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$1.67	$0.33	($1.34)	-80.17%	$0.00	$0.00	$0.00	-

Variance Explanation

Capital: The primary reason for the variance is due to the complexity of the engineering bore profile and the permitting process, which has led to the delay of the shorted casing at 35E & Arlington, pushing its construction to 2024.

O&M: None.

V. DIMP MULTI-YEAR PLAN

As mentioned above, many of the DIMP projects are initiatives that will span multiple years. As such, the Company has formulated a five-year plan for those projects that will extend beyond 2024. As the Company continues to execute its risk-based strategy and replacement projects planned in advance of 2025 and beyond, pipe segments displaying the highest level of relative risk will be targeted. Therefore, it is anticipated that there will be an increase in the number of overall projects.

The information provided in the table below depicts the current estimated costs for future years, broken out by capital and O&M expenditures. It is important to note that in many cases the figures presented are high-level estimates. More detailed annual estimates will be developed in the future. Many of these projects require detailed design and engineering that has not yet been performed. Additionally, coordination with local government entities, securing rights-of-way and permits, resource and equipment availability and unforeseen circumstances all can have an impact on final construction estimates.

DIMP 2026-2029 Plan[13]
($ Millions)

	2026 Estimates		2027 Estimates		2028 Estimates		2029 Estimates	
Project	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**	**Capital**	**O&M**
Poor Performing Mains	$20.05	$0.00	$20.62	$0.00	$21.03	$0.00	$21.53	$0.00
Poor Performing Services	$6.68	$0.57	$6.87	$0.64	$7.00	$0.71	$7.17	$0.78
Intermediate Pressure (IP) Lines Assessments	$0.00	$0.32	$0.00	$0.25	$0.00	$0.26	$0.00	$0.27
Cross Bores	$0.00	$1.30	$0.00	$1.35	$0.00	$1.41	$0.00	$1.46
Distribution Valve Replacement	$0.61	$0.00	$0.62	$0.00	$0.64	$0.00	$0.65	$0.00
Casing Renewal	$5.00	$0.00	$5.12	$0.00	$5.24	$0.00	$5.37	$0.00
Total	**$32.34**	**$2.19**	**$33.23**	**$2.24**	**$33.91**	**$2.38**	**$34.71**	**$2.51**

[13] Capital figures denoted represent total estimated capital expenditures, including removal costs.

VI. MANDATED RELOCATIONS

Mandated relocations are projects that require the Company 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. The Company must invest capital to achieve these relocations and establishment of service via infrastructure at a different location.

2025 Mandated Relocation Projects

The Company requests recovery of the following capital expenditures associated with Mandated Relocations:

2025 Estimated Mandated Relocation Project Costs ($ Millions)

Mandated Relocation Program	2025 Capital	2025 O&M
Total 2025 Capital Expenditures and O&M	$17.22	$0.00
Total 2025 Minnesota Revenue Requirement	**$9.42**	**$0.00**

Mandated relocation projects were first included in the Company's 2021 GUIC Rider Petition.[14] The capital-related cost estimates for 2025 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads.

Project Summary and Scope

The Company has currently been notified of two discrete mandated relocation projects that will need to occur in 2025. The mandated relocation work in 2025 includes the following discrete projects:

- **Hugo Line:** This is a planned 2025 project to relocate 2,000 feet of 12-inch/16-inch steel per request of Ramsey County in White Bear Lake.

[14] Docket No. G002/M-20-799

- **<u>Inver Grove Heights 117th St. Reconstruction:</u>** This is a planned 2025 project to relocate 5,300 feet of 3-inch PEA/6-inch steel per request of the city of Inver Grove Heights.

In addition to the discrete projects noted above, the Company also budgets for routine relocation projects each year. Relocation routines are comprised of smaller (typically less than $300,000) projects involving the renewal of mains due to relocations. The amounts included in the 2025 GUIC Rider Petition are based on historical data and anticipated costs, as the Company most often does not receive information about small relocations ahead of any given calendar year.

2024 Mandated Relocation Projects

<u>Project Summary and Scope</u>
The Company was notified of three discrete mandated relocation projects that are occurring in 2024. The mandated relocation work in 2024 includes the following discrete projects:

- **<u>Dawn Ave Relocation:</u>** This is a multi-year (2023 and 2024) project. In 2023, the project is a relocation of 11,000 feet of 2-inch PE main near Inver Grove Heights, MN which is in conflict with a city reconstruction project. In 2023, the city has scaled down the project significantly, reducing the gas main conflict in the area. The minor relocations were successfully carried out in 2023, and there will not be any further funding required from this project in 2024.

- **<u>Stillwater County Rd 5 Relocate:</u>** This project is a relocation of a 2-inch and 4-inch main. Existing main conflicts with a Washington County reconstruction project for County Rd 5. This project was scheduled to begin in 2021; however, due to changes in Washington County's plans this project was shifted to 2023 and 2024.

- **<u>Breckenridge Ave Reconstruction:</u>** This project is a city of St. Cloud, MN driven neighborhood revitalization project. During the city's effort to complete this project, Xcel Energy will need to relocate approximately 12,000 feet of the existing 2-inch main due to proposed conflicts. This project is scheduled to begin in 2024, alongside the city project taking place in the area.

DIMP and Mandatory Relocations Overview

In addition to the discrete projects noted above, the Company also budgets for routine relocation projects each year. Relocation routines are comprised of smaller (typically less than $300,000) projects involving the renewal of mains due to relocations. The amounts included in the 2024 GUIC Rider Petition are based on historical data and anticipated costs, as the Company most often does not receive information about small relocations ahead of any given calendar year.

The following are the Mandated Relocation project costs originally included in the Company's 2024 GUIC Rider Petition,[15] as compared to revised 2024 costs estimates based on current-year project developments and actual construction activity:

2024 Estimated Project Costs
($ Millions)

Mandated Relocation Program	2024 Capital, As Filed	2024 Capital Estimates	Variance	% Capital Variance
Total 2024 Capital Expenditures	$15.23	$28.15	$12.92	84.8%
Total 2024 Minnesota Revenue Requirement	**$6.21**	**$6.27**	**$0.07**	**1.02%**

The capital-related cost estimates for 2024 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads not related to internal labor. The 2024 project details for each project are presented in Attachment D1.

Variance Explanation

Capital: Variance of $12.9 million driven by $12.8 million in emerging mandated relocation projects for 2024. This was partially offset by the deployment of $5.0 million in mandated relocation working capital funding.

[15] Docket No. G002/M-23-457.

2023 Mandated Relocation Projects

Project Summary and Scope

The Company had several discrete mandated relocation projects as well as routine relocations (projects typically less than $300,000) taking place in 2023. These projects were located throughout the six areas as summarized below:

Geographic Area (by Division)	Number of Mandated Relocation Projects
Newport	3
Northwest	13
Southeast	2
St. Paul	4
White Bear Lake	2
Wyoming	1
Total	**23**

The following are the Mandated Relocation project costs originally included in the Company's 2023 GUIC Rider Petition,[16] as compared to actual 2023 costs.

2023 Actual Project Costs
($ Millions)

Mandated Relocation Program	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance
Total 2023 Capital Expenditures	$14.02	$20.12	$6.10	43.5%
Total 2023 Minnesota Revenue Requirement	**$4.92**	**$4.09**	**($0.83)**	**(16.8%)**

The capital-related cost estimates for 2023 exclude internal labor and include materials, outside services, transportation, and a portion of construction overheads not related to internal labor. The 2023 project details for each project are presented in Attachment D1.

[16] Docket No. G002/M-22-578.

Variance Explanation

Capital: The $6.1 million increase, is primarily driven by $10.9 million of emerging mandated relocation projects and updated forecasts of $1.2 million on Stillwater County Rd 5, May Township, and Metro Gold Line projects. This increase was offset by reductions in estimated costs and completion in 2023 for the Dawn Ave project ($0.7 million), and estimated cost of routine relocation projects ($3.4 million).

VII. MANDATED RELOCATIONS MULTI-YEAR PLAN

The information provided in the table below depicts the current estimated costs for future years, broken out by capital and O&M expenditures. It is important to note that in many cases the figures presented are high-level estimates. More detailed annual estimates will be developed in the future. Many of these projects require detailed design and engineering that has not yet been performed. Additionally, coordination with local government entities, securing rights-of-way and permits, resource and equipment availability and unforeseen circumstances all can have an impact on final construction estimates.

Mandated Relocations 2026-2029 Plan[17]
($ Millions)

Mandated Relocations	2026 Estimates		2027 Estimates		2028 Estimates		2029 Estimates	
	Capital	O&M	Capital	O&M	Capital	O&M	Capital	O&M
Total	$18.13	$0.00	$18.06	$0.00	$18.48	$0.00	$18.93	$0.00

[17] Capital figures denoted represent total estimated capital expenditures, including removal costs.

DIMP 2023-2025 Project Detail

CAPITAL

Program	Regulation	WBS Structure	2023 Actuals	Cost Per Unit (CPU)	2024 Actuals[1]	2024 Forecast	2024 Total	Cost Per Unit (CPU) Assumptions	2025 Plan	Cost Per Unit (CPU) Assumptions
Distribution Valve Replacement	Code 49 CFR Part 192.1007(d).	E.0010011.005	$ 513,301	See Attachment D1(e) for actual cost results.	$ 155,159	$ 294,658	$ 449,817	See Attachment D1(f)	$ 472,000	See Attachment D1(g)
Poor Performing Mains	PHMSA Advisory Bulletin Nos. ADB-07-01, ADB-02-07, ADB-12-05, and ADB-08-02.	E.0010011.003; E.0010043.019; E.0010038.070	$26,155,360	$71.46/ft. for mains installed by contractors and internal resources in 2022. Difference between actuals and those on the detail Attachment D1(a) are for restoration charges related to work in-serviced in 2021, with carryover costs in 2022 as well as non-GUIC recoverable internal labor. Footage and CPU were already captured within previous detail.	$ 6,925,036	$ 13,041,595	$ 19,966,631	Based on 2023 actuals, 2024 forecast is $74.02/ft for mains installed by contractors and internal resources. Difference between dollar forecast and those on the detail tab are for restoration charges related to work in-serviced in 2023, with carryover costs in 2024. Footage and CPU were already captured within previous detail.	$ 19,531,000	Based on 2023 actuals, 2025 forecast is $74.02/ft. for contractor-performed work and internal/local projects. Considered the best available information.
Poor Performing Services		E.0010011.004	$ 3,082,975	$1,985 per service installed by contractors and internal resources in 2023. Difference between actuals and those on the detail Attachment D1(a) are for restoration charges related to services in-serviced in 2022, with carryover costs in 2023 as well as non-GUIC recoverable internal labor. Footage and CPU were already captured within previous detail.	$ 951,007	$ 2,986,705	$ 3,937,712	Based on 2023 actuals, 2024 forecast is $1,985 per service installed by contractors and internal resources. Difference between forecast on 2024 tab and those on the detail tab are for restoration charges related to services in-serviced in 2023, with carryover costs in 2024. Footage and CPU were already captured within previous detail.	$ 6,500,000	Based on 2023 actuals, 2025 forecast is $1,985/service for contractor-performed work and internal/local projects. Considered the best available information.
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(d).	E.0000007.053; E.0000043.001; E.0010075.051; E.0000045.001; E.0000146.001; E.0010033.034; E.0010075.067	$ 2,242,337	See Attachment D1(d) for actual cost results.	$ 271,129	$ 1,046,957	$ 1,318,086	See Attachment D1(d)	$ -	See Attachment D1(d)
Casing Renewal	Code 49 CFR Part 192.467	E.0010011.012; E.0010043.026	$ 331,086	See Attachment D1(h) for actual cost results.	$ 132,326	$ 2,735,362	$ 2,867,688	See Attachment D1(h)	$ 3,198,000	See Attachment D1(h)
TOTAL DIMP CAPITAL			**$ 32,325,059**		**$ 8,434,656**	**$ 20,105,278**	**$ 28,539,934**		**$ 29,701,000**	

O&M

Program	Regulation	WBS Structure	2023 Actuals	Cost Per Unit (CPU)	2024 Actuals[1]	2024 Forecast	2024 Total	Cost Per Unit (CPU) Assumptions	2025 Plan	Cost Per Unit (CPU) Assumptions
Intermediate Pressure (IP) Line Assessments	Code 49 CFR Part 192.1007(d).	A.0008510.114.001.005; A.0008610.004.001.005	$ 245,941	See Attachment D1(d) for actual cost results.	$ 72,810	$ 145,000	$ 217,810	See Attachment D1(d)	$ 278,333	See Attachment D1(d)
Poor Performing Services		A.0008610.004.001.001	$ 702,936		$ 39,722	$ 357,476	$ 397,198		$ 526,935	
Sewer & Gas Line Conflict Investigation	Dockets Nos. G002/M-12-248 and G002/M-10-422	A.0008610.004.001.006	$ -		$ -	$ 195,000	$195,000	Estimated at $300 per address for sewer camera and $10,000 per address if a dig is needed to clear	$ 1,250,000	Estimated at $300 per address for sewer camera and $10,000 per address if a dig is needed to clear
TOTAL DIMP O&M			**$ 948,877**		**$ 112,532**	**$ 697,476**	**$ 810,008**		**$ 2,055,268**	

[1] Actual costs through June 2024

DIMP 2023 Project Detail - Replacements

NSP-MN Main & Service Replacement Projects 2023								
Area	City	Work Order	Description	Services Replaced	Total Service Cost	Installed Footage	Total Main Cost	Class Location
Moorhead	Moorhead	109076594	12th Ave & 20th St S	27	$ 77,702	3,632	$ 201,674	1
	Moorhead	109573368	6th St & 16th Ave S	21	$ 41,685	5,025	$ 329,099	4
	Moorhead	109076589	27th Ave & 18th St S	40	$ 69,940	7,029	$ 440,939	4
	Moorhead	110029417	Romkey & Park	72	$ 178,912	7,834	$ 342,885	4
	Moorhead	107489509	20th St N	92	$ 151,841	6,541	$ 579,406	1
Newport	West St. Paul	109213081	Oakdale Ave	0	$ -	11,020	$ 3,810,992	4
	Woodbury	109349227	Woodlane Dr & Valley Creek Rd	8	$ 24,747	6,806	$ 1,097,149	4
	West St Paul	109344052	Thompson & Humboldt	20	$ 56,230	3,681	$ 481,630	4
	West St Paul	109441199	Marie & Humboldt	46	$ 94,649	4,596	$ 602,172	3
	Mendota Heights	109260832	Eagle Ridge	72	$ 174,395	6,221	$ 563,419	3
Northwest	St. Cloud	108412430	1st St S	44	$ 175,229	10,839	$ 1,364,224	4
	St. Cloud	109477283	3rd Street N & 6th Ave N	1	$ 2,327	2,564	$ 343,112	4
	St. Cloud	109120728	14th St S & 9th Ave S	15	$ 55,679	2,144	$ 137,687	1
	St. Cloud	106624322	Cloverleaf Trailer	155	$ 403,285	10,948	$ 737,053	4
	Delano	108383901	3rd St	113	$ 237,293	15,040	$ 1,444,602	4
Southeast	Faribault	108768787	7th St NW	33	$ 28,008	3,457	$ 954,059	4
	Faribault	108460123	Lyndale Ave N	24	$ 56,278	7,790	$ 1,697,464	4
	Faribault	108332343	2nd St NW	28	$ 57,472	5,718	$ 980,048	1
	Faribault	Multiple	Prairie Ave SW	231	$ 325,126	21,381	$ 1,534,922	4
	Northfield	109497640	Maple Street - Northfield	21	$ 38,593	2,742	$ 208,680	4
	Red Wing	108453954	Cannon River Ave	11	$ 20,863	3,868	$ 445,441	1
	Red Wing	109149924	Grandview Mobile Home Park	98	$ 152,675	8,249	$ 422,231	1
	Winona	109637518	E 2nd St & Franklin St	29	$ 59,422	3,375	$ 607,378	4
Rice Street	St. Paul	109234029	Water Street	12	$ 100,469	5,546	$ 3,737,044	4
	St. Paul	109644716	Arlington Ave	0	$ -	750	$ 342,516	4
	St. Paul	107913921	W 7th and Homer	9	$ 15,842	6,628	$ 306,329	4
	St. Paul	109490588	Milton St N & Pierce Butler Rte	8	$ 19,898	1,813	$ 181,528	4
	Maplewood	109121135	McKnight Rd (Phase 1)	51	$ 62,082	6,974	$ 434,720	3
	Maplewood	109208781	McKnight Rd (Phase 2)	54	$ 81,897	9,757	$ 1,117,947	3
	Maplewood	109442773	McKnight Rd (Phase 3)	36	$ 55,599	4,641	$ 769,678	3
	Roseville	109494258	Cleveland Ave N	5	$ 12,822	4,088	$ 475,721	4
White Bear Lake	Maplewood	109126011	Lakewood Dr	33	$ 48,274	3,971	$ 264,330	4
	Maplewood	108281462	Gary Pl	16	$ 36,032	1,830	$ 545,623	4
	New Brighton	109080555	Old Hwy 8 (Part 1)	17	$ 57,109	8,695	$ 1,658,890	4
	New Brighton	109373793	County Rd E	28	$ 55,307	5,732	$ 898,621	4
	New Brighton	109850976	Mooney Dr	78	$ 122,715	4,097	$ 311,733	3
	Oakdale	109494614	10th St N	15	$ 18,296	3,021	$ 244,112	4
	Roseville	109728987	Beacon St	35	$ 67,070	3,596	$ 402,495	3
	Shoreview	109023640	Hall St N	36	$ 65,136	5,482	$ 386,826	2
Wyoming	Forest Lake	109021142	1st Street SE	18	$ 35,236	2,824	$ 323,516	4
	Stacy	109036727	Sunrise Estates	128	$ 185,794	7,863	$ 416,501	1
2023 DIMP Main & Service Replacements Total				**1,780**	**$ 3,521,929**	**247,808**	**$ 32,144,396**	

** Project list above includes non-recoverable internal labor.*

DIMP 2024 Project Detail - Replacements

NSP-MN Main & Service Replacement Projects 2024										
Area	**City**	**Work Order**	**Description**	**Estimated Services**	**Estimated Service Cost**	**Service CPU**	**Estimated Footage**	**Estimated Main Cost**	**Main CPU**	**Class Location**
Grand Forks	East Grand Forks	107877932	EGF//DIMP/BUS HWY 2 ACS - BERTS 4"	10	$ 19,850	$ 1,985	8,400	$ 621,768	$ 74.02	1
	East Grand Forks	109270893	EGF/DIMP/2ND AVE NE - ACS 8" & 6"	7	$ 13,895	$ 1,985	5,950	$ 440,419	$ 74.02	1
Moorhead	Moorhead	111268192	14th St N - Moorhead	73	$ 144,905	$ 1,985	4,080	$ 302,002	$ 74.02	1
Newport	Cottage Grove	111409240	80th Street & Jamaica Ave	26	$ 51,610	$ 1,985	5,050	$ 373,801	$ 74.02	2
	Cottage Grove	111444639	Grange Blvd & Hadley Ave S	1	$ 1,985	$ 1,985	1,180	$ 87,344	$ 74.02	4
	Inver Grove Heights	111389984	Cahill Ave - IGH	20	$ 39,700	$ 1,985	4,200	$ 310,884	$ 74.02	4
	St. Paul	112255365	Livingston Ave & Wood St	61	$ 121,085	$ 1,985	3,400	$ 251,668	$ 74.02	1
	St. Paul Park	111410931	8th Ave & 3rd St	157	$ 311,645	$ 1,985	10,662	$ 789,201	$ 74.02	4
	St. Paul Park	112260466	Broadway Ave & Pleasant Ave	13	$ 25,805	$ 1,985	810	$ 59,956	$ 74.02	4
	St. Paul Park	111317940	Dixon Dr & Gary Dr	59	$ 117,115	$ 1,985	2,800	$ 207,256	$ 74.02	1
	West St. Paul	109213081	Oakdale Ave - West St. Paul	27	$ 53,595	$ 1,985	8,800	$ 651,376	$ 74.02	4
	West St. Paul	111500591	Kopp Dr & Sperl St	65	$ 129,025	$ 1,985	5,500	$ 407,110	$ 74.02	3
Northwest	Delano	108383901	Delano - 3rd St N	178	$ 353,330	$ 1,985	29,040	$ 2,149,541	$ 74.02	4
	Watertown	111248007	Jefferson Ave & Stevens St	74	$ 146,890	$ 1,985	5,600	$ 414,512	$ 74.02	4
	St. Cloud	109477283	3rd Street N & 6th Ave N	21	$ 41,685	$ 1,985	3,202	$ 237,012	$ 74.02	4
	St. Cloud	112433112	Hwy 10 - St. Cloud	1	$ 1,985	$ 1,985	0	$ -	$ 74.02	4
	Waite Park	112170427	3rd Street N - Waite Park	42	$ 83,370	$ 1,985	5,650	$ 418,213	$ 74.02	4
Southeast	Red Wing	109349237	W 3rd Street - Red Wing	38	$ 75,430	$ 1,985	8,585	$ 635,481	$ 74.02	4
	Red Wing	111243557	N Service Dr & Tyler Rd N (Grade 2 leak)	10	$ 19,850	$ 1,985	2,800	$ 207,256	$ 74.02	4
	Winona	109970557	5th Street W & Pelzer St	258	$ 512,130	$ 1,985	6,714	$ 496,970	$ 74.02	4
	Winona	109637518	E 2nd St & Franklin St	45	$ 89,325	$ 1,985	3,650	$ 270,173	$ 74.02	4
	Winona	111269658	Gilmore Ave & W Sarnia St	56	$ 111,160	$ 1,985	4,600	$ 340,492	$ 74.02	4
	Faribault	111506455	Roberds Lake BLVD & 180th St	43	$ 85,355	$ 1,985	4,700	$ 347,894	$ 74.02	1
	Faribault	109104521	Wilson Ave & 4th St NW	23	$ 45,655	$ 1,985	750	$ 55,501	$ 74.02	1
	Northfield	111524570	Jefferson Rd - Northfield	51	$ 101,235	$ 1,985	1,400	$ 103,628	$ 74.02	4
	Northfield	111389987	Fremont St E & Nevada St	33	$ 65,505	$ 1,985	2,500	$ 185,050	$ 74.02	1
Rice Street	Lauderdale	111067402	Fulham St & Roselawn Ave W	19	$ 37,715	$ 1,985	1,800	$ 133,236	$ 74.02	4
	Roseville	109636613	Cleveland Ave & Oakcrest Ave	29	$ 57,565	$ 1,985	2,499	$ 184,976	$ 74.02	4
	Roseville	111067402	Larpenteur Ave W - Roseville	10	$ 19,850	$ 1,985	2,320	$ 171,726	$ 74.02	4
	Roseville	109442778	Long Lake Rd & Ct Rd C2	19	$ 37,715	$ 1,985	5,459	$ 404,075	$ 74.02	4
	Saint Paul	106617902	Saint Paul - Snelling & Concordia	44	$ 87,340	$ 1,985	2,750	$ 203,555	$ 74.02	4
	Saint Paul	109234029	Saint Paul - Water Street	28	$ 55,580	$ 1,985	6,150	$ 455,223	$ 74.02	4
	St. Paul	106444128	Edgerton & Wheelock	12	$ 23,820	$ 1,985	1,400	$ 103,628	$ 74.02	4
	St. Paul	109528460	Hampden Ave - St. Paul	59	$ 117,115	$ 1,985	4,625	$ 342,343	$ 74.02	4
	St. Paul	111635443	Payne Ave & Wells St	41	$ 81,385	$ 1,985	2,480	$ 183,570	$ 74.02	4
	St. Paul	111341737	Wabash Ave - St. Paul	1	$ 1,985	$ 1,985	300	$ 22,206	$ 74.02	4
	St. Paul	111341737	Wabash Ave - St. Paul (Casings)	10	$ 19,850	$ 1,985	1,950	$ 144,339	$ 74.02	4
White Bear Lake	Arden Hills	111281770	Innovation Way (Fernwood St)	3	$ 5,955	$ 1,985	1,900	$ 140,638	$ 74.02	4
	Maplewood	106686148	Century & Stillwater	26	$ 51,610	$ 1,985	3,750	$ 277,575	$ 74.02	4
	Maplewood	110968103	E Shore Drive - Maplewood	14	$ 27,790	$ 1,985	1,800	$ 133,236	$ 74.02	3
	Maplewood	111261214	Edgerton St - Maplewood - 12"	0	$ -	$ 1,985	2,000	$ 148,040	$ 74.02	3
	Maplewood	110968089	Phalen Pl - Maplewood	4	$ 7,940	$ 1,985	125	$ 9,253	$ 74.02	3
	New Brighton	109636613	Cleveland Ave & 2nd St SE	30	$ 59,550	$ 1,985	2,028	$ 150,139	$ 74.02	3
	New Brighton	109595989	Lakeside MHP - New Brighton	134	$ 265,990	$ 1,985	6,042	$ 447,229	$ 74.02	3
	New Brighton	109373793	New Brighton - County E (old hwy 8 part 2)	123	$ 244,155	$ 1,985	9,415	$ 696,898	$ 74.02	4
	Shoreview	109023640	Brookside MHP - Shoreview	227	$ 450,595	$ 1,985	7,918	$ 586,090	$ 74.02	2
	Vadnais Heights	109528451	Rice St & Rustic Pl	1	$ 1,985	$ 1,985	1,765	$ 130,664	$ 74.02	2
	White Bear Lake	109203950	3rd St & Krech Ave - Phase 1	93	$ 184,605	$ 1,985	4,900	$ 362,698	$ 74.02	2
	White Bear Lake	13396803	3rd St & Krech Ave - Phase 2	40	$ 79,400	$ 1,985	1,850	$ 136,937	$ 74.02	2
	White Bear Lake	109528451	Chatham & Chippenham Lane	9	$ 17,865	$ 1,985	700	$ 51,814	$ 74.02	3
Wyoming	Forest Lake	109916061	1st ST NW - Forest Lake 8in	25	$ 49,625	$ 1,985	4,100	$ 303,482	$ 74.02	4
	Chisago City	110491758	Interlachen Road - Chisago City	45	$ 89,325	$ 1,985	3,600	$ 266,472	$ 74.02	3
2024 Designed DIMP-related Main Replacement Total				**2,438**	**$ 4,839,430**	**$ 1,985**	**223,650**	**$ 16,554,548**	**$ 74.02**	

** Project list above includes non-recoverable internal labor.*
*** Cost estimates based on $74.02/ft of main and $1,985/service per Attachment D1*

DIMP 2025 Project Detail - Replacements

NSP-MN Main & Service Replacement Projects 2025									
Area	**City**	**Description**	**Estimated Services**	**Estimated Service Cost**	**Service CPU**	**Estimated Footage**	**Estimated Main Cost**	**Main CPU**	**Class Location**
Grand Forks	East Grand Forks	17th St NE & 5th Ave	11	$ 21,835	$ 1,985	1,200	$ 88,824	$ 74.02	4
Moorhead	Moorhead	3rd Ave & Main Ave - Moorhead	22	$ 43,670	$ 1,985	1,700	$ 125,834	$ 74.02	1
Newport	Inver Grove Heights	Babcock Trail& Cenex Dr	4	$ 7,940	$ 1,985	700	$ 51,814	$ 74.02	4
	Inver Grove Heights	Bovey Ave & 70th St E	2	$ 3,970	$ 1,985	390	$ 28,868	$ 74.02	4
	Inver Grove Heights	Carmen Ave & Claude Way	7	$ 13,895	$ 1,985	2,215	$ 163,954	$ 74.02	4
	St. Paul	Ruth St N & Upper Afton Rd	11	$ 21,835	$ 1,985	1,700	$ 125,834	$ 74.02	4
	West St. Paul	Thompson Ave W & Smith Ave S	15	$ 29,775	$ 1,985	1,500	$ 111,030	$ 74.02	3
	Inver Grove Heights	70th SE & Delaney Ave	7	$ 13,895	$ 1,985	775	$ 57,366	$ 74.02	3
	Saint Paul	State St & Fillmore Ave	32	$ 63,520	$ 1,985	3,800	$ 281,276	$ 74.02	4
Northwest	Delano	CR 16 & Honeytree Dr	45	$ 89,325	$ 1,985	5,400	$ 399,708	$ 74.02	1
	St. Cloud	25th Ave N - St. Cloud	31	$ 61,535	$ 1,985	1,450	$ 107,329	$ 74.02	4
	St. Cloud	7th St N & 22nd Ave N	46	$ 91,310	$ 1,985	3,000	$ 222,060	$ 74.02	1
	St. Cloud	Hwy 10 - St. Cloud	4	$ 7,940	$ 1,985	0	$ -	$ 74.02	4
	St. Cloud	University Dr SE & 10th Ave SE	227	$ 450,595	$ 1,985	9,800	$ 725,396	$ 74.02	1
Southeast	Faribault	30th St & Park Ave	25	$ 49,625	$ 1,985	5,700	$ 421,914	$ 74.02	4
	Faribault	16th St & 21st Ave	121	$ 240,185	$ 1,985	7,900	$ 584,758	$ 74.02	1
	Faribault	Faribault Prison	15	$ 29,775	$ 1,985	4,000	$ 296,080	$ 74.02	4
	Northfield	Old Fellows Rd & 5th St W	42	$ 83,370	$ 1,985	2,300	$ 170,246	$ 74.02	4
	Faribault	Prairie Ave & Division St	11	$ 21,835	$ 1,985	1,350	$ 99,927	$ 74.02	4
	Faribault	22nd Ave NW & Western Ave NW	50	$ 99,250	$ 1,985	1,800	$ 133,236	$ 74.02	1
	Red Wing	East Ave & 9th St	50	$ 99,250	$ 1,985	3,326	$ 246,191	$ 74.02	4
	Red Wing	Red Wing Ave - Red Wing	111	$ 220,335	$ 1,985	6,000	$ 444,120	$ 74.02	4
	Red Wing	Motel Ave & Hwy 61	211	$ 418,835	$ 1,985	12,300	$ 910,446	$ 74.02	4
	Red Wing	Hwy61 & 5th St	0	$ -	$ 1,985	1,200	$ 88,824	$ 74.02	1
	Winona	Steuben St - Winona	125	$ 248,125	$ 1,985	6,650	$ 492,233	$ 74.02	4
	Winona	Gilmore Ave & Hilbert St	87	$ 172,695	$ 1,985	8,511	$ 629,984	$ 74.02	4
	Winona	Winona - 4th and 5th Street	57	$ 113,145	$ 1,985	3,608	$ 267,064	$ 74.02	4
	Winona	Knopp Valley - Winona	195	$ 387,075	$ 1,985	13,481	$ 997,864	$ 74.02	4
	Winona	Main st & 5th Street	2	$ 3,970	$ 1,985	182	$ 13,472	$ 74.02	4
	Winona	Huff Street - Winona	18	$ 35,730	$ 1,985	2,000	$ 148,040	$ 74.02	4
Rice Street	Roseville	Co Rd B - Roseville	9	$ 17,865	$ 1,985	2,000	$ 148,040	$ 74.02	4
	Roseville	Rice Street & CR C W	34	$ 67,490	$ 1,985	5,442	$ 402,817	$ 74.02	4
	Roseville	Sheldon St - Roseville	37	$ 73,445	$ 1,985	1,900	$ 140,638	$ 74.02	4
	Roseville	Transit Ave - Roseville	38	$ 75,430	$ 1,985	3,800	$ 281,276	$ 74.02	4
	Saint Paul	Saint Paul - Edgerton Street	53	$ 105,205	$ 1,985	10,000	$ 740,200	$ 74.02	4
	St. Paul	Laurel Ave & Pierce St N	123	$ 244,155	$ 1,985	3,100	$ 229,462	$ 74.02	4
	St. Paul	Edgcumbe Rd - St. Paul	17	$ 33,745	$ 1,985	1,000	$ 74,020	$ 74.02	3
	St. Paul	Lexington Pkwy & Jefferson Ave	30	$ 59,550	$ 1,985	1,900	$ 140,638	$ 74.02	3
	St. Paul	Rice St N & Como Ave	29	$ 57,565	$ 1,985	3,248	$ 240,395	$ 74.02	4
	St. Paul	Scheffer Ave & Chatsworth St	27	$ 53,595	$ 1,985	800	$ 59,216	$ 74.02	3
	St. Paul	STP - Payne Ave & Reaney Ave	45	$ 89,325	$ 1,985	3,136	$ 232,127	$ 74.02	4
	St. Paul	University Ave - St. Paul (Casings)	21	$ 41,685	$ 1,985	1,880	$ 139,158	$ 74.02	4
	St. Paul	Maryland Ave E - Saint Paul	4	$ 7,940	$ 1,985	1,250	$ 92,525	$ 74.02	3
White Bear Lake	Arden Hills	Harriet Ave & Benton Way	52	$ 103,220	$ 1,985	6,900	$ 510,738	$ 74.02	4
	Arden Hills	Innovation Way & Cty Rd F	6	$ 11,910	$ 1,985	2,800	$ 207,256	$ 74.02	2
	Lake Elmo	50th St & Demontreville Tr	26	$ 51,610	$ 1,985	3,300	$ 244,266	$ 74.02	1
	Mounds View	County Rd I	2	$ 3,970	$ 1,985	301	$ 22,280	$ 74.02	3
	Mounds View	County Rd H	10	$ 19,850	$ 1,985	1,404	$ 103,924	$ 74.02	4
	New Brighton	5th St NW & Inca Ln	37	$ 73,445	$ 1,985	2,700	$ 199,854	$ 74.02	4
	New Brighton	3rd St NW - New Brighton	44	$ 87,340	$ 1,985	3,500	$ 259,070	$ 74.02	3
	New Brighton	Morris St & True St	34	$ 67,490	$ 1,985	1,900	$ 140,638	$ 74.02	3
	New Brighton	17th Ave & 3rd St	20	$ 39,700	$ 1,985	2,200	$ 162,844	$ 74.02	3
	North Oaks	Buffalo Rd - North Oaks	62	$ 123,070	$ 1,985	13,900	$ 1,028,878	$ 74.02	4
	North Oaks	E Oaks Rd - North Oaks	10	$ 19,850	$ 1,985	2,700	$ 199,854	$ 74.02	2
	Oakdale	10th St N - Oakdale	3	$ 5,955	$ 1,985	600	$ 44,412	$ 74.02	3
	Oakdale	8th St N & Greenway Ave N	38	$ 75,430	$ 1,985	2,150	$ 159,143	$ 74.02	3
	Oakdale	Glenbrook Ave - Oakdale	80	$ 158,800	$ 1,985	4,050	$ 299,781	$ 74.02	3
	Roseville	Rice Street 6" - Roseville	50	$ 99,250	$ 1,985	7,479	$ 553,596	$ 74.02	4
	Shoreview	Churchill St - Shoreview	256	$ 508,160	$ 1,985	9,600	$ 710,592	$ 74.02	4
	Oakdale	Hadley Ave - Oakdale	41	$ 81,385	$ 1,985	3,950	$ 292,379	$ 74.02	4
	Oakdale	Twenty-Nine Pines - Maplewood	153	$ 303,705	$ 1,985	6,000	$ 444,120	$ 74.02	3
	Shoreview	Mackubin St - Shoreview	43	$ 85,355	$ 1,985	2,700	$ 199,854	$ 74.02	2
	White Bear Lake	4th St & Bald Eagle Ave	53	$ 105,205	$ 1,985	2,600	$ 192,452	$ 74.02	4
	White Bear Lake	Clark Ave & 2nd St	34	$ 67,490	$ 1,985	3,400	$ 251,668	$ 74.02	4
	North St. Paul	Cowern Pl & 6th St N	21	$ 41,685	$ 1,985	1,800	$ 133,236	$ 74.02	3
	Maplewood	Arcade St & Frost Ave	160	$ 317,600	$ 1,985	1,500	$ 111,030	$ 74.02	3
	Mounds View	Quincey St & Bronson Dr - DIMP	461	$ 915,085	$ 1,985	18,150	$ 1,343,463	$ 74.02	4
	Mounds View	CR I & Edgewood Drive	25	$ 49,625	$ 1,985	1,200	$ 88,824	$ 74.02	4
Wyoming	Forest Lake	8th Ave SE - Forest Lake	38	$ 75,430	$ 1,985	2,350	$ 173,947	$ 74.02	1
	Forest Lake	Beach Dr SE - Forest Lake	39	$ 77,415	$ 1,985	1,800	$ 133,236	$ 74.02	1
	Forest Lake	July Ave N & 204th St N	25	$ 49,625	$ 1,985	3,200	$ 236,864	$ 74.02	1
	Forest Lake	N Shore Trail & Jason Ave	71	$ 140,935	$ 1,985	4,900	$ 362,698	$ 74.02	1
	Forest Lake	Ideal Ave - Forest Lake	45	$ 89,325	$ 1,985	2,050	$ 151,741	$ 74.02	1
	Stacy	Forest Blvd & Stacy Trail	10	$ 19,850	$ 1,985	1,916	$ 141,822	$ 74.02	4
	Lindstrom	Lindstrom MHP	84	$ 166,740	$ 1,985	3,000	$ 222,060	$ 74.02	1
2025 Designed DIMP-related Main Replacement Total			**4,073**	**$ 8,084,905**	**$ 1,985**	**278,194**	**$ 20,591,898**	**$ 74.02**	

** Remaining projects are in-process of development and design; this work will take place the last quarter of 2024 and the first two quarters of 2025.*
*** Cost estimates based on $74.02/ft of main and $1,985/service per Attachment D1*

2023		
Project Name	**Project Description**	**Assumptions**
River Crossing Assessments 2023 Actual O&M Costs:	· Project Type: Underwater Assessment · Regulation: 49 CFR 192.1007(d) · Overview: Underwater assessment to inspect for pipeline damage. · Locations: Brainerd, Clear Lake, Faribault, Newport, Northfield, St. Augusta, St. Cloud, St. Paul, St. Stephen, and Watab MN. · 2022 Assessment Period: September – October 2022 $90,000 (2022 Carryover)	· Mobilization: $4,000 · Assessment cost: $3,000 - $13,000
Hugo Line 2023 Actual O&M Costs:	· Project Type: AC Mitigation · Regulation: 49 CFR 192.1007(d) · Overview: Design and installation of AC mitigation as required. · Location: Hugo, MN · 2023 Assessment Period: May – October 2022 $16,000	· Cost/mile of survey: $2,100 · Dig cost: $30,000 - $80,000
Rice Royalton A 2023 Actual O&M Costs:	· Project Type: Follow up digs · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of ECDA baseline assessment. · Location: Watab, MN · 2023 Assessment Period: May – October 2023 $66,000	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
Rice Royalton B and C 2023 Actual O&M Costs:	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Watab, MN · 2023 Assessment Period: May – October 2023 $26,000	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
Kwik Trip Lateral 2023 Actual O&M Costs:	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA to provide baseline assessment. · Location: Inver Grove Heights, MN · 2023 Assessment Period: May – October 2023 $43,000	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
Winona Support Line 2023 Actual O&M Costs:	· Project Type: Follow up digs · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of ECDA baseline assessment. · Location: Winona, MN · 2023 Assessment Period: May – October 2023 $9,000	· Cost/mile of survey: $6,500 · Dig cost: $30,000 - $80,000
County Road B - Lexington to Hamline & Cty Rd C Capital Project (no O&M) 2023 Actuals: $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 3.4 mile replacement project; the pipeline was constructed in 1953-1959 using vintage materials and construction methods which, while acceptable at the time, are now associated with threats that contribute to the probability of failures in the pipelines. · Location: Roseville, MN · Construction expected to be completed in 2021 and 2022; restoration in 2023 761,919	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
Langdon Line - Scott Blvd to 1st St Capital Project (no O&M) 2023 Actuals: $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 5.8 mile replacement project; the pipeline was originally installed in 1958 using multi diameter piping and mechanical couplings. Replacement with a new single diameter pipeline will make the line capable of being inspected with ILI tools. · Location: Cottage Grove, MN & St. Paul Park, MN · Construction expected to be completed in 2021 and 2022; restoration in 2023 92,535	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
Brainerd/Nisswa/Co Rd 13 Capital Project (no O&M) 2023 Actuals: $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 2,500 feet of 6-inch pipe replacement project. This pipeline was identified as bare steel through direct examination in 2021. · Location: Nisswa, MN · Engineering, Design, and Construction in 2023 - Differed to later years due to identified risk of Watab exposed pipe	· Benefits: Removing identified high-risk bare steel · Current Classification: Distribution · Future Classification: Distribution
East County Line/ MAOP Capital Project (no O&M) 2023 Actuals: $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 2,500 feet of 24-inch pipe replacement project. This pipeline did not have traceable, verifiable, and complete records. · Location: Newport, MN · Engineering, Design, and Construction in 2022 & 2023 698,470	· Benefits: Removing identified high-risk bare steel · Current Classification: Transmission · Future Classification: Transmission
Watab Exposed Pipe Capital Project (no O&M) 2023 Actuals: $	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: ~1000 feet of 8-inch pipe replacement project. This pipeline was identified as exposed underwater after a diving inspection in 2022. · Location: Watab, MN · Engineering, Design, and Construction in 2023 1,302,218	· Benefits: Removing identified high-risk exposed main underwater · Current Classification: Distribution · Future Classification: Distribution

2024		
Project Name	**Project Description**	**Assumptions**
River Crossing Assessments	· Project Type: Underwater Assessment · Regulation: 49 CFR 192.1007(d) · Overview: Underwater assessment to inspect for pipeline damage. · Locations: Various · 2024 Assessment Period: September – October 2024	· Mobilization: $4,000 · Assessment cost: $3,000 - $13,000
2024 O&M Costs:	$75,300	
R443 Integrity Dig	· Project Type: Integrity Dig · Regulation: 49 CFR 192.1007(d) · Overview: Performing a dig with added NDE assessment · Location: Linwood, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
2024 O&M Costs:	$52,710	
R5000 Lateral	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: Winona, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
2024 O&M Costs:	$20,536	
Faribault Feeder Line	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: Faribault, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
2024 O&M Costs:	$10,268	
St. Bonifacious Lateral	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: St. Bonifacious, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
2024 O&M Costs:	$30,804	
Conway Lateral	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: Maplewood, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
2024 O&M Costs:	$13,691	
Babcock Lateral	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: Sunfish Lake, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
2024 O&M Costs:	$13,691	
Kwik Trip Lateral	· Project Type: Follow up digs · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of indirect survey baseline · Location: Shakopee, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: $8,000 · Dig cost: $30,000 - $80,000
2024 O&M Costs:	$0	
County Road B - Lexington to Hamline & Cty Rd C Capital Project (no O&M)	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 3.4 mile replacement project; the pipeline was constructed in 1953-1959 using vintage materials and construction methods which, while acceptable at the time, are now associated with threats that contribute to the probability of failures in the pipelines. · Location: Roseville, MN · Construction expected to be completed in 2021 and 2022; restoration in 2023, due to sourcing challenges final security and RCV work completed in 2024	· Benefits: Eliminate poor performance, unknown construction specifications, establish MAOP · Current Classification: Distribution · Future Classification: Distribution
2024 Actuals:	$ 219,510	
Brainerd/Nisswa/Co Rd 13 Capital Project (no O&M)	· Project Type: Pipeline Replacement · Regulation: 49 CFR 192.1007(d) · Overview: 2,500 feet of 6-inch pipe replacement project. This pipeline was identified as bare steel through direct examination in 2021. · Location: Nisswa, MN · Engineering, Design, and Construction in 2024	· Benefits: Removing identified high-risk bare steel · Current Classification: Distribution · Future Classification: Distribution
2024 costs	$1,092,135	

DIMP 2025 Project Detail - IP Line Assessments/Replacements

2025			
Project Name	**Project Description**	**Assumptions**	
River Crossing Assessments	· Project Type: Underwater Assessment · Regulation: 49 CFR 192.1007(d) · Overview: Underwater assessment to inspect for pipeline damage. · Locations: Various · 2024 Assessment Period: September – October 2024	· Mobilization: · Assessment cost:	$4,000 $3,000 - $13,000
2025 Estimated O&M Costs:	$74,862		
Colby Lake Lateral	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: Woodbury, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: · Dig cost:	$8,000 $30,000 - $80,000
2025 Estimated O&M Costs:	$30,713		
East County Line A	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: Newport, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: · Dig cost:	$8,000 $30,000 - $80,000
2025 Estimated O&M Costs:	$33,592		
Langdon Line	· Project Type: Indirect survey · Regulation: 49 CFR 192.1007(d) · Overview: Conducting ECDA like inspections to provide baseline assessment. · Location: Newport, MN · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: · Dig cost:	$8,000 $30,000 - $80,000
2025 Estimated O&M Costs:	$71,983		
Follow Up Integrity Digs	· Project Type: Follow up digs · Regulation: 49 CFR 192.1007(d) · Overview: Follow up digs based on results of indirect survey baseline assessment. · Location: TBD · 2024 Assessment Period: May – October 2024	· Cost/mile of survey: · Dig cost:	$8,000 $30,000 - $80,000
2025 Estimated O&M Costs:	$67,184		

DIMP 2023 Project Detail - Distribution Valve Replacement

NSP-MN Distribution Valve Replacement Projects 2023			
Project Name/Location	**Valve #**	**Size/Mtl**	**Actual Cost**
1403 Concord St S, South St Paul	NEW	2" PE	$ 1,216
Tyler Rd & Bench St, Red Wing **	NEW	6" PE	$ 112
Fry & Edmund, St Paul **	NEW	12" CS	$ 1,463
Bielenberg & Valley Creek Rd, Woodbury **	NEW	4" PE	$ 133
Annapolis & Oakdale, West St Paul **	NEW	8" PE	$ (432)
49th St & 9th Ave, Inver Grove Heights **	NEW	2" PE	$ (3,875)
Hartford Ave & Albert St, St Paul **	NEW	3" CS	$ 82
Edgerton St & Maryland Ave. St Paul **	NEW	2" PE	$ 23,522
Summit & Fairview (Westside), St Paul	EV1325	16" CS	$ 339,255
Marion St, Lake City **	D-3-2	2" CS	$ 5,048
North Service Dr, Red Wing	NEW	6" CS	$ 100,374
Cretin Ave N & Mississippi River Blvd (South of Intersection), St Paul	NEW	12" CS	$ 32,499
Cretin Ave S (Between Goodrich & Fairmount), St Paul	NEW	12" CS	$ 33,258
Cretin & Marshall (North of Intersection), St Paul	NEW	6" CS	$ 99,810
Cretin Ave & Watson, St Paul **	EV1321	12"CS	$ 164,712
2770 Service Dr, Red Wing	Distr	6" CS	$ 4,558
Robert Trail and 60th St, Inver Grove Heights	NEW		$ 10,640
Timber Crest Dr & 70th St (North of Intersection), Cottage Grove	NEW	2" PE	$ 3,294
Woodcrest Dr & Fyrie Dr (South of Intersection), Woodbury	NEW	2" PE	$ 5,691
Cottage Grove Dr & Oak View Dr (West of Intersection), Woodbury	NEW	2" PE	$ 9,513
Victoria & University (North of Intersection), St Paul	NEW	4" PE	$ 27,956
Maryland Ave & St Albans, St Paul	EV1079	8"CS	$ 15,469
Victoria St & Summit Ave, St Paul	NEW	4" PE	$ 10,448
McKnight & Holloway - R278 Inlet Valve, St Paul	EV1283	4" CS	$ 20,174
Victoria St N (between Selby & Dayton), St Paul	NEW	2" PE	$ 8,117
		Actual Total Cost:	**$ 913,037**

Total valves: 24

** Project list above includes non-recoverable internal labor.*

*** 2023 costs represent carryover costs from 2022 installs.*

DIMP 2024 Project Detail - Distribution Valve Replacement

NSP-MN Distribution Valve Replacement Projects 2024			
Project Name/Location	**Valve #**	**Size/Mtl**	**Estimated Cost**
Fairview Ave and Eleanor Ave Grade 2 leak WO#108556278	EV1034	16" CS	$ 190,000
11th St & 14th St, St Cloud	EV6203	12" CS	$ 75,000
Morton St W & Bidwell St (East of Intersection),West St Paul	NEW	6" PE	$ 25,000
75th St E & Cahill Ave (South of Intersection), Inver Grove Heights	NEW	6" CS	$ 40,000
Western Ave N & Co Rd C W (Southside), Roseville	DV6434	8" CS	$ 50,000
Kansas St & 4th St	NEW	8" CS	$ 50,000
Victoria (between Minnehaha & Lafond), St Paul	EV1067	6" PE	$ 40,000
Grenadier Ave S & Beldon Blvd (East of Intersection), St Paul Park	NEW	4" PE	$ 7,500
80th St & 79th St (South East of Intersection), Cottage Grove	EV4734	4" PE	$ 7,500
Summit St. & Maryland Ave, St. Paul	EV1079	8" CS	$ 45,000
Summit St. & Saint Albans St, St. Paul	EV1088	6" CS	$ 45,000
Saint Clair & Fairview (West of Intersection), St Paul	EV1603	4" CS	$ 40,000
Woodbury Dr & Valley Creek Rd (Southwest Corner), Woodbury	DV4696	4" CS	$ 7,500
Bernard St E & Robert St S (West of Intersection), West St Paul	NEW	2" PE	$ 5,000
Smith Ave S & Wyoming St W (Southwest of Intersection), St Paul	NEW	2" PE	$ 5,000
Haskell St W & Hall Ave (South of Intersection), West St Paul	NEW	2" PE	$ 5,000
North of 2270 Saint Johns Dr, Woodbury	NEW	2" PE	$ 5,000
Dewey St & Roblyn Ave STP	EV1330	16" CS	$ 220,000
Holloway & McKnight Maplewood - R278	EV1283	4" CS	
Annapolis St E & Brown Ave (North of Intersection), St Paul	NEW	2" PE	$ 5,000
		Estimated Total Cost:	**$ 867,500**

Total valves: 20

** Known valves, subject to change.*

*** Project list above includes non-recoverable internal labor.*

DIMP 2025 Project Detail - Distribution Valve Replacement

NSP-MN Distribution Valve Replacement Projects 2025			
Project Name/Location	**Valve #**	**Size/Mtl**	**Estimated Cost**
Baker St W & Manomin Ave (South of Intersection), St Paul	NEW	12" CS	$ 100,000
Frank St & Burns (Southside), St Paul (NPT Area)	EV1228	12" CS	$ 100,000
Prior Ave & Milwaukee RR Tracks (Southside), St Paul	EV1332	8" CS	$ 50,000
Roselawn & Fairview (60# side), Roseville	EV1440	8" CS	$ 50,000
Lexington & University (South of Intersection), St Paul	NEW	6" PE	$ 25,000
70th St & Irvin Ave (South of Intersection), Cottage Grove	NEW	4" PE	$ 7,500
Cottage Grove Dr & Dogwood Rd (North of Intersection), Woodbury	NEW	4" PE	$ 7,500
Season Pkwy & Radio Dr (South of Intersection), Woodbury	NEW	4" PE	$ 7,500
Bailey Lake Rd & Pioneer Dr (West of Intersection), Woodbury	NEW	4" PE	$ 7,500
Pioneer Dr & Bailey Rd (West of Intersection), Woodbury	NEW	4" PE	$ 7,500
Grenadier Ave S & Grange Blvd(North of Intersection), Cottage Grove	NEW	4" PE	$ 7,500
Highwood Ave & Schaller Dr (West of Intersection), Maplewood	NEW	4" PE	$ 7,500
Dodd Rd & Willow Ln (Eastside), Mendota Heights	DV3781	3" CS	$ 7,500
Western Ave N & Front Ave (Northside), St Paul	DV3342	6" CS	$ 40,000
Thompson Ave & 19th Ave N, South St Paul	DV1544	3" PE	$ 7,500
4th Ave S & Maire Ave (West of Intersection), South St Paul	NEW	2" PE	$ 5,000
Curtice St W & Delaware Ave (West of Intersection), St Paul	NEW	2" PE	$ 5,000
Annapolis St E & Brown Ave (North of Intersection), St Paul	NEW	2" PE	$ 5,000
Smith Ave S & Wyoming St W (Southeast of Intersection), St Paul	NEW	2" PE	$ 5,000
Bernard St W & Charlton St (South of intersection), West St Paul	NEW	2" PE	$ 5,000
Seventh St & Goodrich (East of Intersection), St Paul	NEW	2" PE	$ 5,000
Arcade & Lawson (Northeast of Intersection), St Paul	NEW	2" PE	$ 5,000
13th Ave & Lincoln Ave (West of Intersection), St Paul Park	NEW	2" PE	$ 5,000
9th Ave & Lincoln Ave (West of Intersection), St Paul Park	NEW	2" PE	$ 5,000
Cottage Grove Dr & Eagle View Blvd (West of Intersection), Woodbury	NEW	2" PE	$ 5,000
Granadier Ave S & Gary Blvd (North of Intersection), St Paul Park	NEW	2" PE	$ 5,000
Avon St N & Summit Ave (North of Intersection), St Paul	NEW	2" CS	$ 7,500
Granada Ave & 70th St (North of Intersection), Cottage Grove	NEW	2" PE	$ 5,000
Bailey Rd & Hill Rd (North of Intersection), Woodbury	NEW	2" PE	$ 5,000
Radio Dr & Cobbleston Rd (West of Intersection), Woodbury	NEW	2" PE	$ 5,000
Place Holder for NW Valves	TBD	TBD	$ 45,000
Place Holder for WBL/WYO Valves	TBD	TBD	$ 65,000
		Estimated Total Cost:	**$ 620,000**

Total valves: 32

** Known valves, subject to change.*

*** Project list above includes non-recoverable internal labor.*

DIMP 2023-2025 Project Detail - Casing Renewal

2023

Casing Location	Size	Leaking	Shorted	Actual Cost
Bore Hwy 36 & Rice St.	12"	N	Y	$ 49,929
12in Bore across I-35E at Arlington	12"	N	Y	$ 281,157
			Total	**$ 331,086**

2024

Casing Location	Size	Leaking	Shorted	Estimated Cost
Casing under RR tracks 400' E of Rice St. at entrance to 1900 Rice St. (St. Paul Water)*	4"	N	Y	$ 155,000
12in Bore across I-35E at Arlington	12"	N	Y	$ 2,712,688
			Total	**$ 2,867,688**

2025

Casing Location	Size	Leaking	Shorted	Estimated Cost
RR Crossing at Fairview & Cty C	4"	N	Y	$ 155,000.00
Renew intersection at Wabash & Vandalia (12in, 8in, 4in)	6”	N	Y	$ 480,000.00
12in main at W 5th St & East Ave	12"	N	N	$ 764,000.00
16in on University Ave.	16"	N	N	$ 1,268,000.00
Gervais Ave & HWY 61	6"	N	Y	$ 533,000.00
			Total	**$ 3,200,000.00**

DIMP 2024 Project Detail - Sewer Mitigation

NSP-MN Sewer Conflict Investigation - 2024 Projects					
Project Name	**City**	**State**	**Estimated Service Count**	**Risk Score**	**Risk Level**
Lake Ave Legacy Survey	Spicer	Minnesota	120	6	High
Selby Ave Legacy Survey	St. Paul	Minnesota	396	9	High
Finn Street Legacy Survey	St. Paul	Minnesota	209	9	High
Sherburn Ave Legacy Survey	St. Paul	Minnesota	33	9	High
Front Ave Legacy Survey	St. Paul	Minnesota	315	9	High
7th Ave Legacy Survey	North St. Paul	Minnesota	242	9	High
Glen Oaks Ave Legacy Survey	White Bear Lake	Minnesota	386	9	High
Price Ave Legacy Survey	Maplewood	Minnesota	111	9	High
11th Street Legacy Survey	Moorhead	Minnesota	168	9	High

DIMP 2025 Project Detail - Sewer Mitigation

NSP-MN Sewer Conflict Investigation - 2025 Projects					
Project Name	City	State	Estimated Service Count	Risk Score	Risk Level
5th Street Legacy Sewer	St. Paul	Minnesota	791	9	High
Granada Ave Legacy Sewer	Cottage Grove	Minnesota	280	9	High
Cedar Ave Legacy Sewer	White Bear Lake	Minnesota	154	9	High
30th Ave S Legacy Sewer	Moorhead	Minnesota	261	9	High
Moreland Ave W Legacy Sewer	West Saint Paul	Minnesota	989	9	High
New Brighton Rd Legacy Sewer	New Brighton	Minnesota	315	9	High
Kathleen Drive Legacy Sewer	West Saint Paul	Minnesota	234	9	High
Butler Ave E Legacy Sewer	West Saint Paul	Minnesota	315	9	High
Park St Legacy Sewer	Saint Paul	Minnesota	231	9	High

DIMP Quantitative Risk Assessment Scores for 2025

Quantitative Risk Assessment for 2025 GUIC Programs and Initiatives

DIMP

Methodology

Xcel Energy's risk assessment methodology is a process to evaluate unwanted consequences and the likelihood of the consequences occurring on the Company's natural gas infrastructure. The goal of the Company's integrity programs is to protect the public, property, and the environment from pipeline failures.

The purpose of this risk assessment methodology is to develop a quantitative risk score and assign a risk category (high, medium, low) for identified projects that are funded through the Company's GUIC Rider.

These quantitative risk assessment methodologies assign numeric values to likelihood and consequences by using available data and quantifying assessments. In some cases, subject matter expert (SME) input is utilized.

DIMP Quantitative Risk Assessment Scores

DIMP Poor Performing Mains & Services Project Risk

SEE ATTACHMENT D2(b)

Uses Commercial Software: J-DIMP™ by JANA

Data Inputs include data such as Leak Date, Leak Class, Leak Cause, Pipe Length, Pipe Material, Pipe Pressure, Pipe Diameter, Pipe Coating, Year Installed, Cathodic Protection, Presence of Excess Flow Valve on Service, Building Class and proximity to pipeline, and Population Density.

A Bundle (or project) is comprised of mains and services with similar material, diameter, pressure, cathodic protection status, and installation year. Typical projects consist of approximately 1,500 feet of main and associated services and risers, and any valves that may be attached to the mains piping. Bundle lengths can vary significantly from project to project and serve as a starting point for establishing the scope of DIMP Poor Performing Main & Service projects.

The risk score used to rank the risk associated with each Bundle is calculated using the risk scores of each asset within the Bundle and is then normalized by the length (in feet) of the assets within the bundle.

Main Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

Service Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

Valve Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

Riser Risk = ∑ (Likelihood of Failure x Consequence of Failure) for each threat

The risk scores are generated for each year over the course of the next decade (10 years) to allow for an understanding of the rate of change of the risk associated with the projects.

The likelihood of failure in the J-DIMP™ model is calculated utilizing a Weibul Proportional Hazard Model for 25 specific threat types derived from the 8 primary threat categories established by PHMSA in 192.1007PHMSA (and noted on page 2, Attachment D).

Consequence of failure in the J-DIMP™ model is calculated for each threat for each individual asset and is based on the probability and magnitude of a number of loss of function or loss of containment scenarios that may come about due to each threat, and considers consequence factors such as Health and Safety, Property Damage, and Economic Loss.

As can be noted from the calculation above, Main & Service project risk scores (i.e. the Bundle Risk / Length scores) are calculated on a per foot basis. This allows for a direct comparison of projects that may vary significantly in length. The projects are grouped into high-, medium- and low-risk categories based on the resulting Bundle Risk / Length scores generated by the model.

DIMP Quantitative Risk Assessment Scores

Projects may also be designated as high or medium risk via engineering judgment provided by subject matter experts (SMEs) who evaluate factors such as recent leakage which is not yet in the J-DIMP model, field observations that the pipe has significant corrosion, the presence of problematic material types such as bare steel or copper, the presence of mechanical compression couplings, the presence of poor CP conditions, or emerging risk factors based on industry incidents or findings.

As the J-DIMP™ model is primarily used to rank and evaluate potential replacement projects, it is important to calculate not only the inherent risk presented by an asset in the Xcel Energy gas distribution network, but also the risk reduction achieved by replacing the asset, or mitigated risk. Mitigated risk is calculated as the difference in risk between a current asset (the baseline risk condition) and a hypothetical new asset in the same location and subject to the same operating conditions.

The two risk profiles needed to calculate the mitigated risk for every Bundle (or project) are evaluated in the same way as the baseline Bundle Risk score, and the resulting Mitigated Bundle Risk score is provided on a per foot basis to allow for a direct comparison of assets and bundles that may vary significantly in length. As with the baseline risk scores, the mitigated risk scores are generated for each year over the next decade (10 years); for project evaluation, the sum of the mitigated risk score over the decade is used.

The projects are grouped into high-, medium- and low-risk reduction categories based on the resulting Mitigated Bundle Risk / Length scores by the model. The resulting distribution of these scores is shown in the tables below.

Projects that are in the high- or medium-risk baseline risk categories and are also in the high-risk reduction mitigated risk category, are considered good candidates for selection in the Poor Performing Mains & Services replacement program. On the other hand, Bundles (or projects) that may be in the high- or medium-risk baseline risk categories but are ranked in the medium or low-risk reduction category, may be good candidates for operational changes such as accelerated leak survey.

Risk Reduction Category	Project Risk Scores Range (Mitigated Risk/Foot)	Number of J-DIMP™ Projects Currently Identified as of July 2024	Percentage	Main Mileage Currently Identified as of July 2024	Percentage
High	Score ≥ 1.08	3822	5.18%	507	5.18%
Medium	0.45 < Score < 1.08	8588	11.64%	1140	11.64%
Low	0 ≤ Score ≤ 0.45	61357	83.18%	8143	83.18%
Total	**All**	**73,767**	**100%**	9790	**100%**

DIMP Quantitative Risk Assessment Scores

DIMP Intermediate Pressure (IP) Line Assessments
Line Replacements Project Risk

Project	Regulation	Current Classification	Mechanical Joint	Manufacturing/ Construction Defect	Corrosion	3rd Party Damage	Other Leak History	Conseq-uence	Risk Score	Risk Level
No Replacement Projects Identified for 2025	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

IP = distribution pipeline with MAOP > 60 psig

Used for decisions on replacement or other mitigation necessity.

Data inputs:

- Construction Risk Factor - Presence of Mechanical Joint Joining Method
- Manufacturing/Construction Risk Factor – Post Construction Pressure Test
- History of Corrosion, 3rd Party Damage and other leakage
- Pipeline Class Location

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = (Mechanical Joint Risk Factor + Manufacturing/Construction Risk Factor + Maximum Score of (Corrosion Risk Factor, 3rd Party Damage Risk Factor, Other Leak History Factor)

DIMP Quantitative Risk Assessment Scores

Mechanical Joint Risk Factor Lookup Table

Condition	Score
Pipeline Segment Contains Mechanical Joints	2
Does Not Include Mechanical Joints	0

Manufacturing/Construction Defect Risk Factor Lookup Table

Condition	Score
Post Construction Pressure Test < (MAOP x class location test factor from 192.619(a)(2)) OR Documentation of Pressure Test is not Traceable, Verifiable and Complete (TVC)	2
Post Construction Pressure Test ≥ (MAOP x class location test factor from 192.619(a)(2))	0

Corrosion Risk Factor Lookup Table

Condition	Score
History of Corrosion Leakage	1
Presence of Corrosion Pitting	1
No history of Corrosion leakage or pitting	0

3rd Party Damage Risk Factor Lookup Table

Condition	Score
Presence of 3rd Party Damage	1
No Presence of 3rd Party Damage	0

Other Leak History Risk Factor Lookup Table

Condition	Score
History of Leakage due to Causes other than corrosion or 3rd Party Damage	1
No History of Other Leakage	0

Consequence of Failure Lookup Table

Class Location	Score
4	4
3	3
2	2
1	0.5

DIMP Quantitative Risk Assessment Scores

Projects may also be designated as high risk or medium risk via engineering judgment provided by subject matter experts (SMEs).

<u>Risk Matrix</u>

<table>
<tr><td colspan="3"></td><td colspan="4">Consequence</td></tr>
<tr><td colspan="3"></td><td>Class 1</td><td>Class 2</td><td>Class 3</td><td>Class 4</td></tr>
<tr><td colspan="3"></td><td>0.5</td><td>2</td><td>3</td><td>4</td></tr>
<tr><td rowspan="5">Likelihood of Failure</td><td>Mechanical Coupled AND No TVC Test to criteria AND Corrosion/Leakage/3rd Party</td><td>5</td><td>2.5</td><td>10</td><td>15</td><td>20</td></tr>
<tr><td>Mechanical Coupled AND No TVC Test to criteria AND NOT Corrosion/Leakage/3rd Party</td><td>4</td><td>2</td><td>8</td><td>12</td><td>16</td></tr>
<tr><td>Mechanical Coupled OR No TVC Test to criteria AND Corrosion/Leakage/3rd Party</td><td>3</td><td>1.5</td><td>6</td><td>9</td><td>12</td></tr>
<tr><td>Mechanical Coupled OR No TVC Test to criteria AND NOT Corrosion/Leakage/3rd Party</td><td>2</td><td>1</td><td>4</td><td>6</td><td>8</td></tr>
<tr><td>Not Mechanically Coupled, Pressure Test is TVC and meets criteria, no Corrosion/Leakage/3rd Party</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td></tr>
</table>

(dark)	High Risk, Risk Score ≥ 10
(medium)	Medium Risk, 4 ≤ Risk Score < 10
(light)	Low Risk, Risk < 4

DIMP Quantitative Risk Assessment Scores

DIMP Intermediate Pressure (IP) Line Assessments
Line Assessments Project Risk

Project	Years Since Assessment	Pipeline Class Location	Risk Score	Risk Level
Colby Lake Lateral	Never Assessed	Class 4	12	High
East County Line A	Never Assessed	Class 3	9	High
Langdon Line	Never Assessed	Class 4	12	High

IP = distribution pipeline with MAOP > 60 psig

Used for decisions on prioritizing integrity assessments.

Data inputs:

- Years since last integrity assessment
- Pipeline Class Location
- TIMP risk model scores used for SME analysis when applicable

Risk Score = Likelihood of Failure x Consequence of Failure

DIMP Quantitative Risk Assessment Scores

<u>Risk Matrix</u>

			Consequence			
			Class 1	Class 2	Class 3	Class 4
			1	**2**	**3**	**4**
Likelihood of Failure	Last Assessment > 35 years prior or no previous assessment	**3**	3	6	9	12
	20 years ≤ Last Assessment < 35 years prior	**2**	2	4	6	8
	10 years ≤ Last Assessment < 20 years prior	**1.5**	1.5	3	4.5	6
	Last Assessment < 10 years prior	**0.5**	0.5	1	1.5	2

High Risk, Risk Score ≥ 8
Medium Risk, 4 ≤ Risk Score < 8
Low Risk, Risk < 4

DIMP Quantitative Risk Assessment Scores

DIMP Sewer & Gas Line Conflict

Project Name	City	State	Estimated Service Count	Risk Score	Risk Level
5th Street Legacy Sewer	St. Paul	Minnesota	150	6	High

Results from the previous year's inspections are reviewed and specific areas are targeted that have been determined to have a higher probability of conflicts, as confirmed either through camera inspections or meet installation criteria determined to contain most of the companies found sewer conflicts.

The Company will continue to monitor circumstances that may indicate a need to accelerate or scale back inspections.

DIMP Quantitative Risk Assessment Scores for 2025

Risk assessment methodology is subject to change as the Company monitors the results of ongoing inspections. The current risk assessment approach is summarized below:

Risk Matrix

			Consequence		
			Residential Single Family Structure	Residential Multi-Family Structure	Commercial Building
			1	**2**	**3**
Likelihood of Failure	Community/Area with Prior Conflict	**3**	3	6	9
	Installation date in the 1990's or 2000's Installed via bore In proximity to recent renewal project	**2**	2	4	6
	Area installed post 2009 Area previously inspected Area not installed via bore Known septic areas	**0.5**	0.5	1	1.5

(dark grey)	High Risk: Risk Score ≥ 6
(medium grey)	Medium Risk: Medium Risk, 2 ≤ Risk Score < 6
(light grey)	Low Risk: Risk Score < 2

DIMP Quantitative Risk Assessment Scores for 2025

DIMP Distribution Valve Replacement Project Risk

Project Name/Location	Size / Material	Main Line Valve Operable? Y or N	Vault Condition? Good or Poor	Atmospheric Corrosion Status? Present or Not Present	Likelihood Of Failure Score	Consequence of Failure Score	Risk Score	Risk Level
Frank St & Burns (Southside), St Paul (NPT Area)	12" Steel	N	Poor	Not Present	3.75	1	4	Low **
Prior Ave & Milwaukee RR Tracks (Southside), St Paul	8" Steel	N	Poor	Not Present	3.75	4	15	High
Roselawn & Fairview (60# side), Roseville	8" Steel	N	Poor	Not Present	3.75	2	7.5	Medium
Dodd Rd & Willow Ln (Eastside), Mendota Heights	3" PE	N	Good	Not Present	3.75	4	13	High
Western Ave N & Front Ave (Northside), St Paul	6" Steel	N	Poor	Not Present	3.75	2	7.5	Medium
Thompson Ave & 19th Ave N, South St Paul	3" PE	N	Good	Not Present	3	2	6	Medium

** Justification for low-risk valve replacement has not impacted a lot of customers, but it is high risk given that it may potentially impact the major highways & RR crossings

DIMP Quantitative Risk Assessment Scores for 2025

The current list of inoperable valves was identified during annual inspections and field operating procedures and requires replacement. As valves continue to be inspected by field personnel, exceptions will be reported and will be scored using the method lined out below. If valves score in the medium to high risk, then they may be added to the DIMP Distribution Valve Replacement Program.

Data inputs:

- Number of Premises in Existing Emergency Area due to non-functional valve
- Valve Operability
- Atmospheric Corrosion History
- Vault Condition

Risk Score = Likelihood of Failure x Consequence of Failure

Likelihood of Failure = Valve Operability Risk Factor + Vault Condition Risk Factor + Atmospheric Corrosion Risk Factor

Valve Operability Risk Factor Lookup Table

Valve Operable	**Score**
No	3
Yes	0

Vault Condition Risk Factor Lookup Table

Vault Condition	**Score**
Vault Condition Poor (Inaccessible due to water intrusion)	0.75
Vault Condition Good	0

Atmospheric Corrosion Risk Factor Lookup Table

Atmospheric Corrosion Status	**Score**
Atmospheric Corrosion Present	0.25
Atmospheric Corrosion Not Present	0

Consequence of Failure Lookup Table

Premise Count of Existing Emergency Area if valve remains inoperable	**Score**
Premises in Existing Emergency Area > 4000	4
3000 < Premises in Existing Emergency Area ≤ 4000	3
2000 < Premises in Existing Emergency Area ≤ 3000	2
Premises in Existing Emergency Area ≤ 2000	1

DIMP Quantitative Risk Assessment Scores for 2025

Risk Matrix

			Consequence			
			Existing Emergency Area < 2000 services	2000 < Premises in Existing Emergency Area ≤ 3000	3000 < Premises in Existing Emergency Area ≤ 4000	Premises in Existing Emergency Area > 4000
			1	**2**	**3**	**4**
Likelihood of Failure	Valve Inoperable AND Vault Condition Poor AND Atmospheric Corrosion	**4**	4	8	12	16
	Valve Inoperable AND Vault Condition Poor	**3.75**	3.75	7.5	11.25	15
	Valve Inoperable AND Atmospheric Corrosion	**3.25**	3.25	6.5	9.75	13
	Valve Inoperable	**3**	3	6	9	12
	Valve Operable but Vault Condition Poor AND Atmospheric Corrosion	**1**	1	2	3	4

High Risk, Risk Score ≥ 12
Medium Risk, 6 ≤ Risk Score < 12
Low Risk, Risk < 6

DIMP Quantitative Risk Assessment Scores for 2025

DIMP Distribution Casing Renewal Project Risk

Project Name/Location	Size	Likelihood of Failure Score	Consequence	Risk Score	Risk Level
RR Crossing at Fairview & Cty C	4”	4	3	12	Medium
Renew intersection at Wabash & Vandalia (12in, 8in, 4in)	6”	4	3	12	Medium
4in Bore across HWY-61 @ Clarks Ln	4”	4	3	12	Medium
12in main at W5thst & East Ave	12”	4	3	12	Medium
16in on University Ave, St Paul	16”	4	3	12	Medium

Data inputs:

- Indication of a metallic short or electrolytic short between the casing and carrier pipe
- Guided Wave Ultrasonic Testing (“GWUT”) indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area, in accordance with PHMSA Guided Wave UT Go-No Go Procedures (I.e., “18-point checklist)
- Carrier Pipe diameter, operating pressure and location

Risk Score = Likelihood of Failure x Consequence of Failure

Consequence of Failure = Potential Impact Radius of downstream pipeline (PIR)

$$PIR\ (ft) = .69 * \sqrt{Pressure(psig) * Diameter(in)^2}$$

<u>Likelihood of Failure Lookup Table</u>

Condition	Score
Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short. A leak on the carrier pipe.	4
Indication of an electrolytic contact between the casing and carrier pipe.	3
No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area.	2
Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using the PHMSA Guidelines for Integrity Assessment of Carrier Pipes.	1

DIMP Quantitative Risk Assessment Scores for 2025

<u>Consequence of Failure Lookup Table</u>

Condition	Score
Transmission Carrier Pipe that contains HCA	5
Transmission Carrier Pipe – Class 3 or Class 4; Distribution Main Carrier Pipe – PIR > 100 feet	4
Transmission Carrier Pipe – Class 1 or Class 2; Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	3
Distribution Main Carrier Pipe – PIR ≤ 20 feet	2
Distribution Service Carrier Pipe	1

<u>Risk Matrix</u>

			Consequence				
			Distribution Service Carrier Pipe	Distribution Main Carrier Pipe – PIR ≤ 20 ft.	Transmission Carrier Pipe – Class 1 or Class 2 OR Distribution Main Carrier Pipe – 20 ft. < PIR ≤ 100 ft.	Transmission Carrier Pipe – Class 3 or Class 4 OR Distribution Main Carrier Pipe – PIR> 100 ft.	Transmission Carrier Pipe that Contains HCA
			1	**2**	**3**	**4**	**5**
Likelihood of Failure	Indication of a metallic short between the casing and carrier pipe or unable to verify no metallic short	**4**	4	8	12	16	20
	Indication of an electrolytic contact between the casing and carrier pipe	**3**	3	6	9	12	15
	No indication of a metallic short or electrolytic contact but indication of carrier pipe corrosion metal loss in excess of 5% of the cross-sectional area	**2**	2	4	6	8	10
	Indication of a change in casing integrity based on an evaluation of the casing monitoring program data using PHMSA Guidelines for Integrity Assessment of Cased Pipe	**1**	1	2	3	4	5

High Risk, Risk Score ≥ 15
Medium Risk, 6 ≤ Risk Score < 15
Low Risk, Risk < 6

DIMP Replacements Risk Assessment Scores for 2025

DIMP Problematic Mains & Services

Priority	J-DIMP Mitigated Risk/Foot	Priority Distribution
High	Score ≥ 1.08	70
Medium	0.45 < Score < 1.08	0
Low	0 ≤ Score ≤ 0.45	0
Total	**All**	**70**

Work Order Number	Description	Total Design FT.	Tot. Svc	YR INSTALLED	BASE MATERIAL	BASE PRESSURE	J-DIMP Mitigated Risk/Foot	Class Location
TBD	3rd Ave & Main Ave - Moorhead	1,700	22	1970	PE (Aldyl-A)	2 - 25 (psig)	SME	1
TBD	30th St & Park Ave	5,700	25	1974	PE (Aldyl-A)	26 - 66 (psig)	2.10	4
TBD	16th St & 21st Ave	7,900	121	1968	PE (Aldyl-A)	26 - 66 (psig)	SME	1
TBD	Faribault Prison	4,000	15	Unknown	Coated Steel	26 - 66 (psig)	4.02	4
111248007	CR 16 & Honeytree Dr	5,400	45	Unknown	Coated Steel, PE (Aldyl-A)	26 - 66 (psig)	3.59	1
TBD	Babcock Trail& Cenex Dr	700	4	1973	PE (Aldyl-A)	26 - 66 (psig)	SME	4
TBD	Bovey Ave & 70th St E	390	2	1976	Isolated Coated Steel	26 - 66 (psig)	2.47	4
TBD	Carmen Ave & Claude Way	2,215	7	1980	Coated Steel	26 - 66 (psig)	2.76	4
TBD	Ruth St N & Upper Afton Rd	1,700	11	1964	Coated Steel	2 - 25 (psig)	2.63	4
TBD	Thompson Ave W & Smith Ave S	1,500	15	1964	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	1.56	3
TBD	70th SE & Delaney Ave	775	7	Unknown	Coated Steel	26 - 66 (psig)	SME	3
TBD	East Ave & 9th St	3,326	50	1980	Coated Steel, PE (Aldyl-A)	26 - 66 (psig)	1.31	4
TBD	Co Rd B - Roseville	2,000	9	Unknown	Coated Steel	2 - 25 (psig)	13.47	4
TBD	Rice Street & CR C W	5,442	34	1956	Coated Steel	26 - 66 (psig)	4.38	4
TBD	Sheldon St - Roseville	1,900	37	1954	Coated Steel	2 - 25 (psig)	SME	4
TBD	Transit Ave - Roseville	3,800	38	1952	Coated Steel	2 - 25 (psig)	SME	4
106444128	Saint Paul - Edgerton Street	10,000	53	1955	Coated Steel	2 - 25 (psig)	1.30	4
TBD	Laurel Ave & Pierce St N	3,100	123	1977	PE (Aldyl-A)	26 - 66 (psig)	1.19	4
TBD	Edgcumbe Rd - St. Paul	1,000	17	1978	PE (Aldyl-A)	26 - 66 (psig)	SME	3
TBD	Lexington Pkwy & Jefferson Ave	1,900	30	1978	PE (Aldyl-A)	2 - 25 (psig)	SME	3
109349233	Rice St N & Como Ave	3,248	29	1980	PE (Aldyl-A)	26 - 66 (psig)	3.33	4
TBD	Scheffer Ave & Chatsworth St	800	27	1976	PE (Aldyl-A)	26 - 66 (psig)	SME	3
TBD	STP - Payne Ave & Reaney Ave	3,136	45	1948	Coated Steel	26 - 66 (psig)	3.34	4
TBD	University Ave - St. Paul (Casings)	1,880	21	1963	Coated Steel	26 - 66 (psig)	2.40	4
TBD	25th Ave N - St. Cloud	1,450	31	Unknown	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	4.55	4
TBD	7th St N & 22nd Ave N	3,000	46	1959	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	7.24	1
TBD	Hwy 10 - St. Cloud	0	4	1971	PE (Aldyl-A)	200 (psig)	1.53	4
TBD	Harriet Ave & Benton Way	6,900	52	1974	PE (Aldyl-A)	2 - 25 (psig)	SME	4
TBD	Innovation Way & Cty Rd F	2,800	6	1968	PE (Aldyl-A)	26 - 66 (psig)	1.90	2
TBD	50th St & Demontreville Tr	3,300	26	1978	PE (Aldyl-A)	26 - 66 (psig)	SME	1
TBD	County Rd I	301	2	1950	Coated Steel	2 - 25 (psig)	SME	3
TBD	County Rd H	1,404	10	1971	PE (Aldyl-A)	2 - 25 (psig)	SME	4
TBD	5th St NW & Inca Ln	2,700	37	1961	Coated Steel	2 - 25 (psig)	1.27	4
TBD	3rd St NW - New Brighton	3,500	44	1958	Coated Steel	2 - 25 (psig)	1.27	3
TBD	Morris St & True St	1,900	34	1958	PE (Aldyl-A), Coated Steel	2 - 25 (psig)	SME	3
TBD	17th Ave & 3rd St	2,200	20	1969	PE (Aldyl-A)	2 - 25 (psig)	SME	3
TBD	Buffalo Rd - North Oaks	13,900	62	1969	PE (Aldyl-A)	26 - 66 (psig)	1.50	4
TBD	E Oaks Rd - North Oaks	2,700	10	1969	PE (Aldyl-A)	26 - 66 (psig)	SME	2
TBD	10th St N - Oakdale	600	3	1969	PE (Aldyl-A)	2 - 25 (psig)	SME	3
TBD	8th St N & Greenway Ave N	2,150	38	1969	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	1.19	3
TBD	Glenbrook Ave - Oakdale	4,050	80	1959	Coated Steel	2 - 25 (psig)	1.43	3
TBD	Rice Street 6" - Roseville	7,479	50	1956	Coated Steel	26 - 66 (psig)	4.38	4
TBD	Churchill St - Shoreview	9,600	256	1977	PE (Aldyl-A)	26 - 66 (psig)	1.23	4
TBD	Hadley Ave - Oakdale	3,950	41	1959	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	SME	4
TBD	Twenty-Nine Pines - Maplewood	6,000	153	1976	PE (Aldyl-A), Coated Steel	2 - 25 (psig)	1.18	3
TBD	Mackubin St - Shoreview	2,700	43	1975	PE (Aldyl-A)	26 - 66 (psig)	SME	2
TBD	4th St & Bald Eagle Ave	2,600	53	1961	Coated Steel	26 - 66 (psig)	1.11	4
TBD	Clark Ave & 2nd St	3,400	34	1973	PE (Aldyl-A), Coated Steel	2 - 25 (psig)	3.71	4
TBD	Cowern Pl & 6th St N	1,800	21	1955	Coated Steel	2 - 25 (psig)	SME	3
TBD	Steuben St - Winona	6,650	125	1955	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	2.47	4
TBD	Gilmore Ave & Hilbert St	8,511	87	1966	Coated Steel	26 - 66 (psig)	3.89	4
109596715	Winona - 4th and 5th Street	3,608	57	1962	PE (Aldyl-A), Coated Steel	2 - 25 (psig)	4.24	4
TBD	8th Ave SE - Forest Lake	2,350	38	1975	PE (Aldyl-A)	26 - 66 (psig)	SME	1
TBD	Beach Dr SE - Forest Lake	1,800	39	1971	PE (Aldyl-A)	26 - 66 (psig)	SME	1
TBD	July Ave N & 204th St N	3,200	25	1970	PE (Aldyl-A)	26 - 66 (psig)	SME	1
TBD	N Shore Trail & Jason Ave	4,900	71	1967	PE (Aldyl-A), Coated Steel	26 - 66 (psig)	1.32	1
TBD	Ideal Ave - Forest Lake	2,050	45	1967	PE (Aldyl-A)	26 - 66 (psig)	SME	1
109279760	Forest Blvd & Stacy Trail	1,916	10	1970	PE (Aldyl-A)	26 - 66 (psig)	SME	4
TBD	Knopp Valley - Winona	13,481	195	1974	PE (Aldyl-A)	26 - 66 (psig)	SME	4
TBD	Main st & 5th Street	182	2	1962	Coated Steel	26 - 66 (psig)	5.46	4
TBD	Huff Street - Winona	2,000	18	1966	PE (Aldyl-A), Coated Steel	26 - 66 (psig)	1.46	4
TBD	Red Wing Ave - Red Wing	6,000	111	1959	PE (Aldyl-A), Coated Steel	26 - 66 (psig)	2.94	4
TBD	Motel Ave & Hwy 61	12,300	211	1962	Coated Steel, PE (Aldyl-A)	26 - 66 (psig)	2.00	4
TBD	Old Fellows Rd & 5th St W	2,300	42	1963	Coated steel	26 - 66 (psig)	4.77	4
TBD	Prairie Ave & Division St	1,350	11	1972	PE (Aldyl-A)	26 - 66 (psig)	SME	4
TBD	22nd Ave NW & Western Ave NW	1,800	50	1971	Coated Steel, PE (Aldyl-A)	26 - 66 (psig)	1.18	1
TBD	17th St NE & 5th Ave	1,200	11	1968	PE (Aldyl-A)	26 - 66 (psig)	2.61	4
TBD	Arcade St & Frost Ave	1,500	160	1957	Coated steel	2 - 25 (psig)	SME	3
TBD	Quincey St & Bronson Dr - DIMP	18,150	461	1961	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	1.86	4
TBD	CR I & Edgewood Drive	1,200	25	1967	Coated steel	2 - 25 (psig)	2.97	4
TBD	State St & Fillmore Ave	3,800	32	1965	Coated steel	26 - 66 (psig)	3.04	4
100441814	Lindstrom MHP	3,000	84	1968	PE (Aldyl-A)	26 - 66 (psig)	SME	1
TBD	Maryland Ave E - Saint Paul	1,250	4	1972	Coated steel	26 - 66 (psig)	5.88	3
TBD	Hwy61 & 5th St	1,200	0	1954	Coated steel	26 - 66 (psig)	1.69	1
TBD	University Dr SE & 10th Ave SE	9,800	227	1967	Coated Steel, PE (Aldyl-A)	2 - 25 (psig)	SME	1

*Scoring included for known 2025 projects with completed engineering design.

Mandated Relocations 2023 Project Detail

NSP-MN Mandated Relocation Projects 2023						
Area	**WBS L2**	**WBS L2 Description**	**Party Requesting Relocation**	**Size/Material**	**Actual Footage (feet)**	**Actual Cost**
Various	E.0010006.001	MN - Gas Main Relocations Blanket	Various	Various	Various	$ 6,532,573
White Bear Lake	E.0010038.030	MN/WBL/Stillwater/Cty Rd 5 relocate	Washington County	2" PE	4,000	$ 442,794
				4" PE	1,200	
	E.0010038.074	MN\BAT\Co Rd 65\18400ft 4in relocate	Washington County	2" and 4" PE	18,400	$ 1,039,244
	E.0010038.075	MN\Ga Dist\NWB\Old Highway 8\7400ft	City of New Brighton	8" PE	7,900	$ 1,745,227
	E.0000083.001	MN/SHV/Hodgson Rd/8in Reloc	Ramsey County/Shoreview/City of Vadnais Heights	8" PE	11700	$ 1,173,182
	E.0010038.070	MN/New Brighton/H005 Old HWY 8 Reloc	Ramsey County/City of New Brighton	8" Steel	2800	$ 3,055,869
	E.0000155.001	MN/HGO/TL0215/Line Relocate	Washington County	16" Steel	523	$ 466,424
Northwest	E.0000120.001	MN/Shakopee/Roers Apt/ Main Reloc	Roers Apartments	4" Steel	1,800	$ 633,617
	E.0000136.001	MN/SCL/StCloud Highbanks 12inSteel Relo	City of St. Cloud	12" Steel	1000	$ 103,765
	E.0000006.105	CR 115 Main Relocation	Crow Wing County	4" PE	26000	$ 159,180
	E.0000123.001	MN//BGL/Co Rd 43/2023 Recon	City of Big Lake	6" PE	4,672	$ 500,375
	E.0000135.001	MN/SCL/REN/Division Street Reconstruct	City of St. Cloud	6", 4", and 2" PE	6,400	$ 509,956
	E.0000231.001	MN/MD/Brainerd HWY25 HP Steel Reloc	MN Dept. of Transportation	12" Steel	560	$ 48,948
	E.0010038.055	MN/NW/REL/STC/COOPER	City of St. Cloud	2" PE	2,600	$ 10,940
				6" PE	2,225	
	E.0010038.058	MN/WG/MTR/REL/CENTER	City of Montrose	2" PE	3,600	$ 360
				4" PE	2,600	
	E.0010038.062	MN/NW/STC/REL/CLEAR LAKE LINE-A	MN Dept. of Transportation	6" Steel	4,600	$ 1,321,842
	E.0010038.068	ISA GD CO RD 5 NW RECON 22,000' 4	Isanti County	4" PE	22,000	$ 1,466,575
	E.0010038.066	MN/WATERTOWN/ST BONIFACIOUS CONFLIC	Carver County	4" Steel	1,400	$ 9,506
Newport	E.0010038.052	MN/NPT/2022 Recon/70th St	MN Dept. of Transportation	4" PE	6,400	$ 1,205
	E.0010073.012	Century Ave 20" Steel Relocation	Metro Transit Gold Line Relocation	20" Steel	1564	$ (2,170,851)
	E.0010073.013	MN/NSPM/METRO/GOLD LINE RELOCATION	Metro Transit Gold Line Relocation	2" Steel	1665	$ 461,171
	E.0010038.053	MN/NSPM/METRO/GOLD LINE RELOC PROG	Metro Transit Gold Line Relocation	Various	7,360	$ 968,193
Southeast	E.0010038.069	RDW/2022 Road Reconstruction/E 7th St	City of Red Wing	4" PE & 2" PE	6,900	$ 343,308
	E.0010073.014	MN/WIN/TH43 & TH61 Winona Reconst-GDIST	MN Dept. of Transportation	2" PE	900	$ 91,870
				12" Steel	1,000	
	E.0000114.001	MN/NFD/NFLD/I35 & TH19 Reloc	MN Dept. of Transportation	4" and 6" PE	20,200	$ 304,365
Rice St	E.0010038.046	MN/STP/Recon/Cleveland Ave	Ramsey County	2" PE	950	$ 29,212
				8" Steel	2,896	
	E.0010038.065	MN/STP/Larpenteur Ave E/2800ft 8in	City of Maplewood / Ramsey County	2" PE	500	$ 871,439
				8" PE	2,800	
			Total Cost:			**$ 20,120,289**

** Project list above includes non-recoverable Internal Labor, Overheads, Transportation and Other, which is removed from the revenue requirement.*

Mandated Relocations 2024 Project Detail

NSP-MN Mandated Relocation Projects 2024						
Area	**WBS L2**	**WBS L2 Description**	**Party Requesting Relocation**	**Size/Material**	**Estimated Footage (feet)**	**Estimated Cost**
Various	E.0010006.001	MN - Gas Main Relocations Blanket	Various	Various	Various	$ 11,328,933
Northwest	E.0000006.105	CR 115 Main Relocation	Crow Wing County	4" PE	26,000	$ (64,626)
	E.0000135.001	MN/SCL/REN/Divison Street Reconstruct	City of St. Cloud	6", 4", and 2" PE	6,400	$ 37,778
	E.0000136.001	MN/SCL/StCloud Highbanks 12inSteel Relo	City of St. Cloud	12" Steel	1,000	$ 1,261,322
	E.0010038.062	MN/NW/STC/REL/CLEAR LAKE LINE-A	MN Dept. of Transportation	6" Steel	2,500	$ (19,450)
	E.0010038.068	MN/STC/ISANTI/COUNTY 5/RELOCATION	Isanti County	4" PE	22,000	$ (66,370)
	E.0000355.001	MN/MD/STCL/University Dr Relocation	City of St. Cloud	6" PE	3,000	$ 679,947
	E.0000351.001	MN/PRT/RELO/Sherburne County Rd 28 Recon	Sherburne County	4" Steel	5,800	$ 2,267,801
	E.0000335.001	MN/MD/BCKR/Big Lake CR73 Recon	Sherburne County	4" PE	12,500	$ 1,229,830
	E.0000231.001	MN/MD/Brainerd HWY25 HP Steel Reloc	MN Dept. of Transportation	12" Steel	2,000	$ 1,451,177
	E.0000319.001	MN/SCL/RELO/2nd Ave S Sauk Rapids	City of Sauk Rapids	2" and 8" PE	4,600	$ 847,940
	E.0000334.001	MN/SCL/RELO/Clearwater Rd Relo	City of St. Cloud	4" PE	5,200	$ 979,492
	E.0000363.001	MN/BAX/RELO/Forestview Dr Relo PH2	City of Baxter	2", 4", and 6" PE	10,400	$ 722,942
Newport	E.0010073.013, E.0010038.053	MN/NSPM/METRO/GOLD LINE RELOCATION	Metro Transit	20" Steel	1,200	$ (4,976)
	E.0000403.001	MN/NEW/IGH/INST/117th St Recon	City of Inver Grove Heights	3" PE	200	$ 139,584
				6" Steel	5,100	
Rice St	E.0010038.046	MN/STP/Recon/Cleveland Ave	Ramsey County	8" Steel	94,500	$ 992
	E.0010038.065	MN/STP/Larpenteur Ave E/2800ft 8in	City of Maplewood / Ramsey County	8" Steel	2,800	$ 3,742
	E.0000358.001	MN/STP/NMR/RELO/Robert St	City of St. Paul	6", 4", and 2" PE	3,300	$ 481,512
	E.0000375.001	MN/STP/NMR/RELO/Winthrop/2700ft 2in	City of St. Paul	2" PE	1,300	$ 18,611
				8" Steel	600	
Southeast	E.0010038.069	MNRDW\2023 Road Reconstruction\E 7th	City of Red Wing	2" and 4" PE	315,000	$ 9
	E.0000301.001	MN/MD/NFLD/ Co Rd 79 (Wall St)Recon	City of Northfield	3" PE	4,200	$ 275,445
	E.0010033.015	MN/SE/ML/CSAH 27 Madison Lake Recon	Blue Earth County	4" Steel	9,000	$ 156
				2" PE	2,750	
	E.0000354.001	MN/NFD/RELO/NFLD/College&Water St	MN Dept. of Transportation	4" Steel	2,200	$ 120,973
				2" PE	600	
White Bear Lake	E.0010038.030	MN/WBL/Stillwater/Cty Rd 5 relocate	Washington County	2" PE	4,000	$ 158,796
				4" PE	1,200	
	E.0000083.001	MN/SHV/Hodgson Rd/8in Reloc	Ramsey County/Shoreview/Vadnais Heights	2", 4", and 8" PE	11,700	$ 186,891
	E.0010038.074	MN\BAT\Co Rd 65\18400ft 4in relocate	Washington County	2" and 4" PE	18,400	$ (257)
	E.0010038.075	MN\Ga Dist\NWB\Old Highway 8\7400ft	City of New Brighton	8" PE	7,900	$ (11,017)
	E.0010038.070	MN/New Brighton/H005 Old HWY 8 Reloc	Ramsey County/City of New Brighton	8" Steel	2,800	$ 32,451
	E.0000296.001	MN/MD/NMR/RELO/CoRD12/5800ft 12in - Mahtomedi	Washington County	6" PE	1,400	$ 4,736,883
				12" Steel	5,800	
	E.0000287.001	MN/VDH/NMR/RELO/Woodridge Dr/8000ft 2in	City of Vadnais Heights	2" PE	8,000	$ 470,995
	E.0000337.001	MN/MD/FRL/NMR/RENW/TH 97	MN Dept. of Transportation	2" and 4" PE	9,500	$ 651,391
	E.0000372.001	MN/WBL//RELO/NSPM/TL0215/Hugo Line/CR J Relocate	Ramsey County/MN Dept. of Transportation	12" and 16" Steel	2,000	$ 232,640
			Total Cost:			**$ 28,151,537**

** Project list above includes non-recoverable Internal Labor, Overheads, Transportation and Other, which is removed from the revenue requirement.*

Mandated Relocations 2025 Project Detail

NSP-MN Mandated Relocation Projects 2025						
Area	**WBS L2**	**WBS L2 Description**	**Party Requesting Relocation**	**Size/Material**	**Estimated Footage (feet)**	**Estimated Cost**
Various	E.0010006.001	MN - Gas Main Relocations Blanket	Various	Various	Various	$ 10,277,085
	E.0010006.002	MN - Gas Mandates WCF	Various	Various	Various	$ 4,794,236
White Bear Lake	E.0000372.001	MN/WBL/RELO-TL0215/Hugo Line	Ramsey County	12"/16" Steel	2,000	$ 1,681,519
Newport	E.0000403.001	MN/NEW/IGH/INST/117th St Recon	City of Inver Grove Heights	3" PE/6" Steel	5,300	$ 467,140
			Total Cost			**$ 17,219,980**

** Project list above includes non-recoverable Internal Labor, Overheads, Transportation and Other, which is removed from the revenue requirement.*

Total Expenditures (CWIP plus RWIP excluding Internal Labor) through 2029

	2012 - 2023 Expenditures	2024	2025	2026	2027	2028	2029	Total Expenditures
Total TIMP	$ 152,945,299	$ 4,362,171	$ 19,344,100	$ 6,298,113	$ 4,536,989	$ 3,174,844	$ 3,248,809	$ 193,910,325
Total DIMP	284,231,825	29,171,852	29,408,180	32,027,542	32,903,785	33,584,033	34,391,199	475,718,415
Mandated Relocations	59,198,331	25,823,011	18,038,569	19,003,388	18,924,153	19,372,432	19,839,343	180,199,227
Total GUIC Expenditures	$ 496,375,455	$ 59,357,034	$ 66,790,849	$ 57,329,043	$ 56,364,926	$ 56,131,309	$ 57,479,351	$ 849,827,968

Total Expenditures Roll into Base

	2012 - 2023 Expenditures	2024	2025	2026	2027	2028	2029	Total Expenditures
Total TIMP	$ 130,150,565							$ 130,150,565
Total DIMP	193,073,152							193,073,152
Mandated Relocations	13,603,493							13,603,493
Total GUIC Expenditures	$ 336,827,210	$ -	$ -	$ -	$ -	$ -	$ -	$ 336,827,210

Total Expenditures Remaining in Rider

	2012 - 2023 Expenditures	2024	2025	2026	2027	2028	2029	Total Expenditures
Total TIMP	$ 22,794,734	$ 4,362,171	$ 19,344,100	$ 6,298,113	$ 4,536,989	$ 3,174,844	$ 3,248,809	$ 63,759,760
Total DIMP	91,158,674	29,171,852	29,408,180	32,027,542	32,903,785	33,584,033	34,391,199	282,645,264
Mandated Relocations	45,594,837	25,823,011	18,038,569	19,003,388	18,924,153	19,372,432	19,839,343	166,595,734
Total GUIC Expenditures	$ 159,548,245	$ 59,357,034	$ 66,790,849	$ 57,329,043	$ 56,364,926	$ 56,131,309	$ 57,479,351	$ 513,000,758

* Schedule does not include regulatory adjustments or disallowed projects.

TIMP - Capital Revenue Requirements for 2025

	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Annual 2025
Rate Base														
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	$ 26,973,315	$ 26,973,315	$ 26,973,315	$ 26,993,818	$ 26,993,818	$ 26,993,818	$ 31,815,664	$ 31,815,664	$ 31,815,664	$ 32,204,588	$ 39,927,317	$ 40,868,143	$ 45,011,854	$ 45,011,854
Less Accumulated Book Depreciation Reserve	740,583	775,956	814,011	850,081	888,164	926,248	588,733	633,620	678,506	693,667	744,550	801,545	(134,874)	(134,874)
Less Accumulated Deferred Taxes	2,569,080	2,659,849	2,750,618	2,841,387	2,932,155	3,022,924	3,113,693	3,204,462	3,295,231	3,386,000	3,476,769	3,567,538	3,658,306	3,658,306
End Of Month Rate Base	23,663,652	23,537,510	23,408,686	23,302,351	23,173,498	23,044,645	28,113,238	27,977,582	27,841,927	28,124,921	35,705,998	36,499,061	41,488,421	41,488,421
Average Rate Base (Prior Mo + Cur Month/2)	$ 23,119,533	$ 23,600,581	$ 23,473,098	$ 23,355,518	$ 23,237,924	$ 23,109,072	$ 25,578,941	$ 28,045,410	$ 27,909,754	$ 27,983,424	$ 31,915,459	$ 36,102,530	$ 38,993,741	
Return on Rate Base														
Debt Return (Avg RB * Wtd Cost of Debt)		$ 38,351	$ 38,144	$ 37,953	$ 37,762	$ 37,552	$ 41,566	$ 45,574	$ 45,353	$ 45,473	$ 51,863	$ 58,667	$ 63,365	$ 541,621
Equity Return (Avg RB * Wtd Cost of Equity)		98,729	98,196	97,704	97,212	96,673	107,005	117,323	116,756	117,064	133,513	151,029	163,124	1,394,328
Total Return on Rate Base		$ 137,080	$ 136,340	$ 135,657	$ 134,974	$ 134,225	$ 148,571	$ 162,897	$ 162,109	$ 162,537	$ 185,376	$ 209,696	$ 226,489	$ 1,935,949
Income Statement Items														
AFUDC Pre-Eligible		-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses		$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 528,899
Property Taxes		29,390	29,390	29,390	29,390	29,390	29,390	29,390	29,390	29,390	29,390	29,390	29,390	352,683
Book Depreciation		38,055	38,055	38,069	38,084	38,084	41,485	44,887	44,887	45,161	50,883	56,994	60,581	535,225
Deferred Taxes		90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	1,089,226
Gross Up for Income Tax (see below)		(16,564)	(11,798)	(18,662)	(41,361)	(70,454)	(88,404)	(79,256)	(84,273)	(64,620)	(60,245)	(17,114)	17,331	(535,419)
Total Income Statement Expense		$ 185,724	$ 190,491	$ 183,641	$ 160,957	$ 131,864	$ 117,316	$ 129,865	$ 124,848	$ 144,774	$ 154,872	$ 204,114	$ 242,146	$ 1,970,614
Total Revenue Requirement		**$ 322,805**	**$ 326,831**	**$ 319,298**	**$ 295,931**	**$ 266,089**	**$ 265,887**	**$ 292,762**	**$ 286,957**	**$ 307,312**	**$ 340,248**	**$ 413,810**	**$ 468,635**	**$ 3,906,563**

Capital Structure	
Weighted Cost of Debt	1.94%
Weighted Cost of Equity	5.02%
Required Rate of Return	6.97%

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Annual 2025
Current Income Tax Calculation													
Equity Return	$ 98,729	$ 98,196	$ 97,704	$ 97,212	$ 96,673	$ 107,005	$ 117,323	$ 116,756	$ 117,064	$ 133,513	$ 151,029	$ 163,124	$ 1,394,328
Book Depreciation	38,055	38,055	38,069	38,084	38,084	41,485	44,887	44,887	45,161	50,883	56,994	60,581	535,225
Deferred Taxes	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	90,769	1,089,226
Less Tax Depreciation	268,974	256,974	273,974	331,974	408,974	468,974	458,974	480,974	441,974	448,974	354,974	278,974	4,474,691
Plus CPI-Tax Interest (If Applicable)	355	705	1,165	3,367	8,778	10,542	9,502	19,631	28,772	24,449	13,752	7,468	128,486
Total	$ (41,067)	$ (29,249)	$ (46,267)	$ (102,543)	$ (174,670)	$ (219,173)	$ (196,493)	$ (208,932)	$ (160,209)	$ (149,360)	$ (42,430)	$ 42,968	$ (1,327,426)
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	
Gross Up for Income Tax	$ (16,564)	$ (11,798)	$ (18,662)	$ (41,361)	$ (70,454)	$ (88,404)	$ (79,256)	$ (84,273)	$ (64,620)	$ (60,245)	$ (17,114)	$ 17,331	$ (535,419)

* Schedule does not include regulatory adjustments or disallowed projects.

DIMP and Mandated Relocations - Capital Revenue Requirements for 2025

	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Annual 2025
Rate Base														
CWIP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Plant In-Service	$ 184,289,624	$ 187,293,844	$ 187,873,446	$ 188,966,686	$ 191,239,171	$ 195,613,877	$ 201,156,159	$ 206,308,498	$ 211,608,075	$ 216,497,194	$ 221,208,526	$ 224,939,733	$ 229,770,577	$ 229,770,577
Less Accumulated Book Depreciation Reserve	1,172,207	1,447,271	1,783,436	2,095,125	2,349,289	2,507,038	2,618,290	2,765,561	2,918,585	3,108,135	3,313,439	3,580,895	3,820,008	3,820,008
Less Accumulated Deferred Taxes	6,058,329	6,326,651	6,594,972	6,863,293	7,131,614	7,399,936	7,668,257	7,936,578	8,204,900	8,473,221	8,741,542	9,009,864	9,278,185	9,278,185
End Of Month Rate Base	177,059,087	179,519,923	179,495,038	180,008,268	181,758,267	185,706,904	190,869,612	195,606,358	200,484,591	204,915,838	209,153,545	212,348,974	216,672,384	216,672,384
Average Rate Base (Prior Mo + Cur Month/2)	$ 175,643,705	$ 178,289,505	$ 179,507,481	$ 179,751,653	$ 180,883,268	$ 183,732,586	$ 188,288,258	$ 193,237,985	$ 198,045,475	$ 202,700,214	$ 207,034,691	$ 210,751,259	$ 214,510,679	
Return on Rate Base														
Debt Return (Avg RB * Wtd Cost of Debt)	$ 285,421	$ 289,720	$ 291,700	$ 292,096	$ 293,935	$ 298,565	$ 305,968	$ 314,012	$ 321,824	$ 329,388	$ 336,431	$ 342,471	$ 348,580	$ 3,764,691
Equity Return (Avg RB * Wtd Cost of Equity)	734,776	745,844	750,940	751,961	756,695	768,615	787,673	808,379	828,490	847,963	866,095	881,643	897,370	9,691,667
Total Return on Rate Base	$ 1,020,197	$ 1,035,565	$ 1,042,639	$ 1,044,058	$ 1,050,630	$ 1,067,180	$ 1,093,641	$ 1,122,391	$ 1,150,314	$ 1,177,350	$ 1,202,526	$ 1,224,114	$ 1,245,950	$ 13,456,358
Income Statement Items														
AFUDC Pre-Eligible	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Expenses	$ 32,500	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 127,361	$ 1,528,333
Property Taxes	134,090	200,803	200,803	200,803	200,803	200,803	200,803	200,803	200,803	200,803	200,803	200,803	200,803	2,409,632
Book Depreciation	349,978	355,754	359,185	360,787	364,009	370,373	379,867	390,106	400,113	409,868	419,059	427,142	435,339	4,671,603
Deferred Taxes	239,633	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	3,219,856
Gross Up for Income Tax (see below)	136,327	60,323	81,454	65,415	37,779	(3,116)	(13,132)	18,676	27,437	54,937	67,111	106,883	159,401	663,170
Total Income Statement Expense	$ 892,529	$ 1,012,561	$ 1,037,124	$ 1,022,687	$ 998,273	$ 963,742	$ 963,221	$ 1,005,268	$ 1,024,035	$ 1,061,290	$ 1,082,656	$ 1,130,510	$ 1,191,226	$ 12,492,594
Total Revenue Requirement	**$ 1,912,726**	**$ 2,048,126**	**$ 2,079,764**	**$ 2,066,745**	**$ 2,048,903**	**$ 2,030,922**	**$ 2,056,862**	**$ 2,127,659**	**$ 2,174,350**	**$ 2,238,641**	**$ 2,285,182**	**$ 2,354,623**	**$ 2,437,175**	**$ 25,948,952**

Capital Structure	
Weighted Cost of Debt	1.94%
Weighted Cost of Equity	5.02%
Required Rate of Return	6.97%

	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Annual 2025
Current Income Tax Calculation														
Equity Return	$ 734,776	$ 745,844	$ 750,940	$ 751,961	$ 756,695	$ 768,615	$ 787,673	$ 808,379	$ 828,490	$ 847,963	$ 866,095	$ 881,643	$ 897,370	$ 9,691,667
Book Depreciation	349,978	355,754	359,185	360,787	364,009	370,373	379,867	390,106	400,113	409,868	419,059	427,142	435,339	4,671,603
Deferred Taxes	239,633	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	268,321	3,219,856
Less Tax Depreciation	990,884	1,222,589	1,177,589	1,219,589	1,296,589	1,417,589	1,472,589	1,425,589	1,434,589	1,395,589	1,392,589	1,316,589	1,208,589	15,980,073
Plus CPI-Tax Interest (If Applicable)	4,482	2,223	1,087	700	1,227	2,556	4,171	5,086	5,688	5,640	5,498	4,470	2,751	41,097
Total	$ 337,986	$ 149,553	$ 201,944	$ 162,180	$ 93,662	$ (7,725)	$ (32,557)	$ 46,303	$ 68,023	$ 136,202	$ 166,384	$ 264,986	$ 395,192	$ 1,644,150
Tax Rate (T/(1-T)	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
Gross Up for Income Tax	$ 136,327	$ 60,323	$ 81,454	$ 65,415	$ 37,779	$ (3,116)	$ (13,132)	$ 18,676	$ 27,437	$ 54,937	$ 67,111	$ 106,883	$ 159,401	$ 663,170

* Schedule does not include regulatory adjustments or disallowed projects.

Cost Comparison of Using Contractor vs. In-House Workforce and Equipment for Sewer Inspection

Analysis Assumptions

1. Estimated annual expense levels for sewer conflict inspections are pulled from the most recent filed petitions.
2. Assume 5 mainline trucks at $300K, 5 premise out trucks/vans at $25K, 2 Emergency trucks/vans at $25K.
3. Assumed cost to replace specific equipment and vehicles associated with this work. Based the estimates on conversations with our current vendor performing this work and our assumed costs of ownership.
4. Maintenance of equipment, including specific mechanic personnel for unique equipment or equivalent outsourcing.
5. Assumed insurance costs of 12 dedicated vehicles and equipment to perform this work with Company-owned fleet.
6. Wash stations - assumed costs of $6,000 per station at 14 gas Service Centers, $1,000 annual maintenance and upkeep of each.
7. Purchase and updates of software system for tracking, monthly fees for electronic storage. Initial and ongoing hardware costs for dispatching and completing work.
8. Assume 2 operator employees per truck at $60 per hour rate for qualified labor (fully loaded). Also assume 2% annual wage increase. Emergency Inspection - Assume 2 (fully loaded) after hours premise out crews. Premise out 5 fully loaded employees.
9. Overtime and out of town costs are assumed at 10% of labor costs.
10. Assumed 2 (fully loaded) oversight positions to replicate vendor Management and Supervision.
11. Scheduling - In 2010 through 2012, we had a single contractor staff augmentation resource. Once the program expanded and became long-term, we needed to restructure to dispatch, complete and provide QA/QC assistance based on internal auditing results.
13. Plumber costs are assumed for a licensed plumber or an equivalent outsourcing.
14. Weighted Average Cost of Capital (WACC) Assumptions based on last authorized cap structure from last approved MN Gas Rate Case - Docket No. G002/GR-21-678

WACC	**6.97%**

Cost Comparison of Using Contractor vs. In-House Workforce and Equipment for Sewer Inspection

Ln.		Actuals							
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
	Current State								
1	Annual O&M Expenses (Forecast for 2024 and 2025)	$ 4,175,186	$ 3,639,148	$ 3,462,587	$ 3,464,732	$ 3,447,300	$ 3,381,101	$ 3,519,807	$ 3,284,612
2	Estimated Discount Factor using 2025 WACC	2.24	2.10	1.96	1.83	1.71	1.60	1.50	1.40
3	PV of Costs	9,371,730	7,636,277	6,792,359	6,353,713	5,909,831	5,418,663	5,273,401	4,600,384
4	Cumulative PV of Costs	$ 9,371,730	$ 17,008,007	$ 23,800,366	$ 30,154,080	$ 36,063,911	$ 41,482,573	$ 46,755,975	$ 51,356,358
	Owning the Equipment Comparison								
5	Trucks/Specialized equipment	$ 1,675,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Equipment/Vehicle Replacement	50,000	100,000	150,000	350,000	350,000	350,000	350,000	350,000
7	Vehicle Maintenance	100,000	125,000	150,000	200,000	200,000	200,000	200,000	200,000
8	Insurance	28,800	28,800	28,800	28,800	28,800	28,800	28,800	28,800
9	Vehicle Fuel	131,000	131,000	131,000	131,000	131,000	131,000	131,000	131,000
10	Wash Stations (1 per Gas Service Center, incl maint)	84,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
11	Software - MDTs and Korterra	120,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
12	Employees - fully loaded (17 in 2010-2017, 12 in 2018, 11 in 2019-2025)	2,121,600	2,164,032	2,207,313	2,251,459	2,296,488	2,342,418	2,389,266	2,437,052
13	Overtime and Out of Town Costs (Per Diem, etc.)	212,160	216,403	220,731	225,146	229,649	234,242	238,927	243,705
14	Employee Training/Certification	100,000	25,000	25,000	50,000	25,000	25,000	50,000	25,000
15	Permits	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
16	Management and Supervision (2) fully loaded	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
17	Scheduling (1 in '10-12; 2 from 2013-2019; 1 from 2018-2025) fully loaded	35,000	35,000	35,000	70,000	70,000	70,000	70,000	70,000
18	Plumber costs	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
19	Dig up, inspection and repair (DRR)	150,000	150,000	125,000	100,000	80,000	80,000	65,000	65,000
20	Total Costs	5,037,560	3,259,235	3,356,844	3,690,405	3,694,937	3,745,460	3,806,993	3,834,557
21	Estimated Discount Factor using 2025 WACC	2.24	2.10	1.96	1.83	1.71	1.60	1.50	1.40
22	PV of Costs	11,307,437	6,839,080	6,584,929	6,767,558	6,334,364	6,002,596	5,703,665	5,370,629
23	Cumulative PV of Costs	$ 11,307,437	$ 18,146,517	$ 24,731,446	$ 31,499,003	$ 37,833,367	$ 43,835,963	$ 49,539,628	$ 54,910,257
24	**In-house vs Contractor Favorable / (Unfavorable)**	**$ (1,935,707)**	**$ (1,138,510)**	**$ (931,079)**	**$ (1,344,924)**	**$ (1,769,457)**	**$ (2,353,390)**	**$ (2,783,654)**	**$ (3,553,899)**

Ln.		Actuals						Forecast	
		2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
	Current State								
1	Annual O&M Expenses (Forecast for 2024 and 2025)	$ 2,308,000	$ 2,154,000	$ 516,728	$ 287,120	$ 290,312	$ 298,556	$ 195,000	$ 1,250,000
2	Estimated Discount Factor using 2025 WACC	1.31	1.22	1.14	1.07	1.00	0.93	0.87	0.82
3	PV of Costs	3,021,926	2,636,524	591,270	307,132	290,312	279,103	170,416	1,021,231
4	Cumulative PV of Costs	$ 54,378,284	$ 57,014,808	$ 57,606,078	$ 57,913,210	$ 58,203,522	$ 58,482,625	$ 58,653,041	$ 59,674,272
	Owning the Equipment Comparison								
5	Trucks/Specialized equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Equipment/Vehicle Replacement	350,000	350,000	360,500	371,315	382,454	393,928	405,746	417,918
7	Vehicle Maintenance	200,000	200,000	206,000	212,180	218,545	225,102	231,855	238,810
8	Insurance	28,800	28,800	29,664	30,554	31,471	32,415	33,387	34,389
9	Vehicle Fuel	131,000	131,000	134,930	138,978	143,147	147,442	151,865	156,421
10	Wash Stations (1 per Gas Service Center, incl maint)	14,000	14,000	14,420	14,853	15,298	15,757	16,230	16,717
11	Software - MDTs and Korterra	40,000	40,000	41,200	42,436	43,709	45,020	46,371	47,762
12	Employees - fully loaded (17 in 2010-2017, 12 in 2018, 11 in 2019-2025)	1,640,623	1,455,889	1,291,956	1,146,482	1,017,388	902,830	801,171	710,959
13	Overtime and Out of Town Costs (Per Diem, etc.)	164,062	145,589	149,957	154,455	159,089	163,862	168,777	173,841
14	Employee Training/Certification	16,500	14,000	14,420	14,853	15,298	15,757	16,230	16,717
15	Permits	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
16	Management and Supervision (2) fully loaded	200,000	200,000	210,000	210,000	210,000	215,000	215,000	215,000
17	Scheduling (1 in '10-12; 2 from 2013-2019; 1 from 2018-2025) fully loaded	35,000	35,000	40,000	40,000	40,000	40,000	40,000	40,000
18	Plumber costs	16,500	15,500	25,000	25,000	25,000	25,000	25,000	25,000
19	Dig up, inspection and repair (DRR)	40,000	35,000	40,000	40,000	40,000	40,000	40,000	40,000
20	Total Costs	2,881,485	2,669,778	2,563,046	2,446,105	2,346,400	2,267,112	2,196,632	2,138,534
21	Estimated Discount Factor using 2025 WACC	1.31	1.22	1.14	1.07	1.00	0.93	0.87	0.82
22	PV of Costs	3,772,805	3,267,842	2,932,787	2,616,598	2,346,400	2,119,391	1,919,700	1,747,150
23	Cumulative PV of Costs	$ 58,683,062	$ 61,950,905	$ 64,883,691	$ 67,500,290	$ 69,846,689	$ 71,966,080	$ 73,885,780	$ 75,632,930
24	**In-house vs Contractor Favorable / (Unfavorable)**	**$ (4,304,778)**	**$ (4,936,097)**	**$ (7,277,613)**	**$ (9,587,080)**	**$ (11,643,167)**	**$ (13,483,455)**	**$ (15,232,739)**	**$ (15,958,658)**

Calculation of Estimated Annual GUIC-Related Retirements for 2012-2025

Summary of Annual Retirements

	Annual Retirements
2012	$ 46.63
2013	$ 1,053.48
2014	$ 537,681.23
2015	$ 1,801,070.96
2016	$ 1,269,324.36
2017	$ 2,669,861.62
2018	$ 370,314.71
2019	$ 679,258.69
2020	$ 1,968,282.22
2021	$ 693,051.09
2022	$ 1,849,959.19
2023	$ 4,670,797.92
2024	$ 2,404,602.73
2025	$ 2,404,602.73
Total	$ 21,319,907.57

3-Yr Average Retirements 2021-2023

$ 2,404,603

Calculation of Estimated Annual GUIC-Related Retirements for 2012-2025

Replacement Projects Summary

Project No	Project Description	Install Dates of Replaced Assets
GUIC TIMP		
11503515	ASV/REV Installation on High Pressure systems - MN Rider	No related retirements. New installations
50001418	ASV/REV Instalation on HP	No related retirements. New installations
11615874	East Metro Pipe Replac. Proj HP Gas	1940s/1950s
12013233	East Metro Pipeline Replacement - Reg Installation	1940s/1950s
11676981	East Metro Pipe Replac. Proj Distr	1940s/1950s
11706370	Install Rice & Co Rd Regulator	1940s/1950s
11819647	RTUs - East Metro Pipe Replacement	1940s/1950s
11649797	High Bridge Lateral Replacement	1948/but partial relocation in 1960
34000342	High Bridge Lat Replace Dist Reg	1948/but partial relocation in 1960
11649521	NSPM TIMP Mitigation of ILI Results	Island Line 1950s / East County Line Casings 1960
11651650	NSPM Pre 1950 Trans and IP Pipe	1950s
34003261	NSPM Trans and IP Pipe - Distr	1950s
50000704	MN/WBL/County Rd B Replacement-NSP to Rice	1950s
50000709	MN/STP/ECL Replace-Maplewood to NSP	1957
Multiple WBS	MN/NPT/ECL/MAOP & Casing	1950s
GUIC DIMP		
11649520	NSPM Install 6" and 4" Distribution Valves	No related retirements. New installations
50000646	NSPM Install 6" and 4" Distribution Valves	No related retirements. New installations
11649522	NSPM Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs
50000644	NSPM Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs
11649766	NSPM Programmatic Service Replacement	See Detail on Valve/Mains/Services Tabs
50000645	NSPM Programmatic Service Replacement	See Detail on Valve/Mains/Services Tabs
50002555	MN - Programmatic Main Replacements	See Detail on Valve/Mains/Services Tabs
50002156	MN/STP/STP/St Peter St DIMP	See Detail on Valve/Mains/Services Tabs
50002199	MN/Downtown St Cloud/Low Pressure	See Detail on Valve/Mains/Services Tabs
11813698	Pipeline Data Project Dist - NSPM	No related retirements. New installations
11980562	Hugo Line ILI improvements	No related retirements. Assessment work only
12173704	Replace Emr Vlvs in NSPM metro Dist Sys	See Detail on Valve/Mains/Services Tabs
12173830	NSPM Programmatic Service Reply	See Detail on Valve/Mains/Services Tabs
12173831	NSPM Programmatic Main Replace	See Detail on Valve/Mains/Services Tabs
34000462	Sartell Bridge Replacement	See Detail on Valve/Mains/Services Tabs
50000705	MN/STP/County Rd B Replace-Rice to Hamline	1950s
50000939	MN/Colby Lake Lateral Replace	1964-1965
50000937	MN/Arden Hills/System H05 Replace	1964
50000708	MN/NPT/Langdon Line Replacement	1958

Note: Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

Valve Replacements

Functional Class	Type of Asset Replaced	Project Description	Location	Year Retired Asset was Installed	Quantity Replaced	Year of Replacement	Valve #	Valve Size
Distribution	Valve	Inoperable Emergency Valve	7th & Dale, STP	Uknown	1	2017	EV1241	12" SC
Distribution	Valve	Inoperable Emergency Valve	Cypress & 6th, STP	1974	1	2017	EV1218	6" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria & St. Anthony, STP	Uknown	1	2017	EV1069	6" SC
Distribution	Valve	Inoperable Emergency Valve	Roselawn & McMenomie	1954	1	2017	DV6070	4" SC
Distribution	Valve	Inoperable Emergency Valve	Roselawn & McMenomie	1954	1	2017	DV6068	6" SC
Distribution	Valve	Inoperable Emergency Valve	Roselawn & McMenomie	1954	1	2017	EV6069	6" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & 3rd St E	1954	1	2017	EV1289	4" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & 3rd St E	1954	1	2017	EV1288	8" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & 3rd St E	1954	1	2017	EV1290	4" SC
Distribution	Valve	Inoperable Emergency Valve	McKnight & Hudson Rd	1954	1	2017	EV1291	8" SC
Distribution	Valve	Inoperable Emergency Valve	St. Albans & Alley South of Selby, STP	1974	1	2018	EV1373	4" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria & St. Anthony, STP	Unknown	1	2018	EV1069	6" SC
Distribution	Valve	Inoperable Emergency Valve	Henry Ave & Fleming Field, SSTP	Unknown	1	2018	EV1245	12" SC
Distribution	Valve	Inoperable Emergency Valve	Hamline & County Road "B", RSV	N/A	1	2018	R063 bypass	4" SC
Distribution	Valve	Inoperable Emergency Valve	Forest & Rose, STP	1974	1	2018	EV1202	12" SC
Distribution	Valve	Inoperable Emergency Valve	Robert & Page, STP	1963	1	2018	EV1178	8" SC
Distribution	Valve	Inoperable Emergency Valve	Snelling & Englewood, STP	Unknown	1	2019	EV1020	12" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Juno, STP	1974	1	2019	EV1030	16" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Montreal, STP	1976	1	2019	EV1037	16" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Montreal, STP	1974	1	2019	EV1038	16" SC
Distribution	Valve	Inoperable Emergency Valve	Fairview & Montreal, STP	1975	1	2019	EV1316	16" SC
Distribution	Valve	Inoperable Emergency Valve	Algonquin & Iroquois, STP	1975	1	2019	EV1275	12" SC
Distribution	Valve	Inoperable Emergency Valve	Algonquin & Iroquois, STP	1975	1	2019	EV1276	6" SC
Distribution	Valve	Inoperable Emergency Valve	Hwy 19 W TBS	2002	1	2019	EV3512	8" SC
Distribution	Valve	Inoperable Emergency Valve	Hwy 19 W TBS	2002	1	2019	EV3513	6" SC
Distribution	Valve	Inoperable Emergency Valve	St Albans & Arlington, STP	Unknown	1	2021	EV1074	12" SC
Distribution	Valve	Inoperable Emergency Valve	Dodd Rd & Hwy 110, Mendota Heights	1977	2	2021	EV1107 EV1108	12" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria St N & Co Rd C W, Roseville	1973	1	2021	DV6781	4" SC
Distribution	Valve	Inoperable Emergency Valve	Victoria St N & Woodhill Dr, Roseville	1974	1	2021	EV6149	4" SC
Distribution	Valve	Inoperable Emergency Valve	Marion St & Thomas Ave, St Paul	1974	1	2021	DV1397	3" Steel
Distribution	Valve	Inoperable Emergency Valve	Radio Dr & Dale Rd, Woodbury	1989	1	2021	EV4162	4" PE
Distribution	Valve	Inoperable Emergency Valve	HWY 61 Blvd, Redwing	1958	1	2022	EV3040	6" CS
Distribution	Valve	Inoperable Emergency Valve	Summit & Fairview (Westside), St Paul	1953	1	2023	EV1325	16" Steel
Distribution	Valve	Inoperable Emergency Valve	Arlington Ave & HWY35	1979	1	2023	EV1154	12" Steel

Note: Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

2015 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacements					Main Footage			Service		
Division	**Project**	**WO**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Estimate**	**Actual Replaced**	**Actual Installed from Passport**	**Estimate**	**Replaced**	**Transferred**
St. Paul	STP/ARLINGTON, NEVADA, NEBRASKA BTN. WHITE BEAR & FURNESS	11935351	1977	12	12,760	7,100	12,760	230	223	4
	ROSEVILLE/ COHANSEY ST. PROJECT/ INSTALL 7500' OF 2" PE	12118923	1965	0	7,500	4,530	7,517	74	71	2
	STP / CLARENCE ST BTN ARLINGTON AVE E & HOYT AVE E / DIMP PR	12096468	1967	2	2,600	1,300	1,300	48	46	4
	Barclay/Dieter	12185039	Unknown	-	3,750	2,675	3,925	60	58	4
	STP / IVY AVE E XST: RUTH ST / LOW PRESSURE DIMP PROJECT	12088590	1953	0	16,000	11,350	16,031	218	224	0
	STP / 7TH ST W BTN ALTON & RANKIN ST	12217850	1972	7	2,326	4,660	2,326	24	21	4
	Idaho / Barclay / Clarence	12227467	1960	0	7,350	4,775	7,467	99	93	8
	ROSEVILLE/ GALTIER ST/ INSTALL 4600' OF 2" PE MAIN (DIMP)	12122749	Unknown	-	4,400	2,405	4,560	49	48	0
White Bear Lake	VADNAIS HEIGHTS-5-STAR MOBILE ESTATES-INSTALL 10,480' 2" PE	12100647	1974	9	10,480	9,225	10,124	190	112	77
	LAKE ELMO-CIMARRON MOBILE HOME PARK-SOUTH HALF-RENEW MAIN	12148971	1970	5	15,000	15,234	15,234	250	228	0
	LAKE ELMO-CIMARRON MOBILE HOME PARK-NORTH HALF-RENEW MAIN*	12225339	1970	5	16,709	16,064	16,709	252	237	0
	WBL/OPH/Area D	12200298	1962	0	5,000	4,520	5,097	12	14	7
	Vad Heights - North Star Estates	12226824	1972	7	10,000	7,040	9,485	172	161	8
	BAYPORT 5TH ST S INSTALL 3900' OF 2"PE MAIN RENEW 43 SVCS	12093773	Unknown	-	2,900	2,000	3,845	43	16	23
	NO ST PAUL / 14th AVE E	11945105	1978	13	3,865	2,105	3,999	48	40	6
Wyoming	Forest Lake - Carry-over from 2014	12185020	1968	3	9,000	10,850	8,741	93	68	28
	Forest Lake - 11th Ave & 6th St	12233388	1968	3	4,100	3,310	3,310	36	41	6
	Forest Lake - 1st Ave / 2nd Ave / 8th St / 7th St / 6th St	12234310	Unknown	-	4,650	3,750	4,642	27	43	9
Newport	Cloman Way & Lower 67th St	12262781	1971	6	5,500	3,900	6,322	152	154	0
	ST PAUL PARK /2015 DIMP/ DIXON / BLOSSOM	12148969	Unknown	-	2,204	950	2,224	26	26	0
	2015 DIMP / ST PAUL PK / DIXON DR	12149144	Unknown	-	2,581	1,600	2,549	29	29	0
	2015 DIMP / ST PAUL PK / GARY/ SELBY / DAYTON	12149707	Unknown	-	9,274	5,050	9,274	110	110	0
	ST PAUL PARK / 2015 DIMP / PORTLAND AVE / 13TH / 15TH	12101212	1972	7	1,800	1,240	1,764	16	11	5
	SOUTH ST PAUL / 2015 DIMP / BUTLER / KASSAN	12089427	1974	9	2,224	2,980	2,224	20	15	3
	SOUTH ST PAUL / 2015 DIMP BUTLER AVE / BUTLER CT	12101218	1974	9	2,298	1,200	2,298	30	26	6
	Denton	12255539	1973	8	4,828	4,220	4,828	75	75	0
	Burns Ave	12170859	Unknown	-	6,901	3,900	6,902	85	73	11
St. Cloud	DLH / DIMP / RIVER'S EDGE PARKING	12188957	Unknown	-	250	256	270	2	0	0
	St Cloud - Lincoln Ave*	12223516	Unknown	-	7,750	5,990	6,273	36	18	11
	Watertown	12162124	Unknown	-	10,200	7,030	10,210	95	73	37
	Sauk Rapids - 7th St NE (@ 2nd Ave NE)	12227154	Unknown	-	286	250	250	3	3	0
Southeast	GOODVIEW-LAKE VILLAGE MOBILE HOME PARK	12157111	1974	9	9,989	6,930	8,455	230	192	0
	Northfield Viking Ter	12241776	1970	5	10,550	8,525	7,677	180	180	0
	7th St S - Lake City	12205025	1971	6	1,400	-	1,256	6	0	0
	Hallstrom Dr & Burton St - Red Wing	12218584	1971	6	17,000	14,482	14,482	270	136	25
	Bluffview - Winona	12231997	1971	6	2,000	1,120	1,626	5	12	3
	Bush St & Langsford Ave - Red Wing	12212950	1972	7	5,950	5,100	6,337	85	69	7
	Hillsdale - Hidden Valley Mobile Home Park	12162836	1976	11	10,064	8,115	10,699	185	176	0
Moorhead	Moorehead 30th Ave & 8th St S	12215066 & 12208317	Unknown	-	975	-		1	0	0
	Moorehead Dale & 5th St S	12215099 & 12210767	Unknown	-	1,608	-	1,599	32	0	0
2015 DIMP Main and Service Replacements Total					**254,022**	**195,731**	**244,591**	**3,598**	**3,122**	**298**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (Docket No. G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in Docket No. E,G002/D-07-1528)

Note: Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

2016 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2016						
Area	**Work Order Number**	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot. Svc**
St. Paul	12092489	ST PAUL - ARMSTRONG AVE XST: CHATSWORTH ST S	1990	25	1,350	28
	12328949	ST PAUL - ARMSTRONG AVE	1990	25	7,506	150
	12381180	ST PAUL - ATLANTIC, DULUTH & LARPENTEUR	1955	-	8,900	118
	12294860	ROSEVILLE - GLENHILL, WOODLYNN, CLARMAR	1955	-	7,810	81
	12398688	LAUDERDALE - EUSTIS ST	Unknown	-	1,100	17
	12380740	ROSEVILLE - WEWERS RD	Unknown	-	1,400	15
	12404989	ST PAUL - DOWNTOWN - 10TH-MINNESOTA	1957	-	1,200	5
	12344852	ROSEVILLE - COUNTY RD C, FISK, AVON, GROTTO	1958	-	23,400	305
	12444470	ST PAUL - DOWN TOWN (Kellogg)	1956	-	150	-
	12361662	ST PAUL - JUNO CONTRACTOR PORTION	1980	15	4,750	56
	12358730	ST PAUL - JUNO LOCAL PORTION	1980	15	1,260	20
	12364882	ST PAUL - AURORA - LOCAL PORTION	1980	15	960	36
	12369728	ST PAUL - AURORA - CONTRACTOR PORTION	1980	15	3,875	100
	12317526	ST PAUL - BERKELY-STANFORD-WELLESLY	1980	15	10,440	195
	12294862	ROSEVILLE - SKILLMAN-ELDRIDGE	1963	-	6,700	79
White Bear Lake	12344860	LAKE ELMO - 32ND ST	Unknown	-	8,600	77
	12293638	LAKE ELMO - LAKE ELMO AVE	Unknown	-	6,800	51
	12334697	NORTH ST PAUL - 19TH AVE	1956	-	7,000	85
	12371725	BAYTOWN TWP/ 13606 30TH ST N	Unknown	-	320	5
	12320156	OAKDALE - GROSPOINT AVE	1960	-	16,200	178
	12317855	WHITE BEAR LAKE - FLORENCE ST	1976	11	16,600	109
	12320058	MAPLEWOOD - ROSELAWN AVE	1954	-	12,900	179
	12320143	OAKDALE - GERSHWIN AVE	1967	2	9,500	70
	12320392	SHOREVIEW - DEBRA LN	1976	11	11,200	105
	12317856	SHOREVIEW NANCY PL	1971	6	7,600	85
	12275730	OAKDALE GREENE AVE	Unknown	-	2,150	22
Wyoming	12334677	FOREST LAKE - 2ND ST SE	1972	7	10,900	128
Newport	12346387	SOUTH ST PAUL - 3RD AVE S - 6TH ST S	Unknown	-	1,680	28
	12352620	MENDOTA HTS - 3RD ST-VANDALL-SOMERSET	1968	3	1,900	22
	12352631	ST PAUL PARK - 13TH-14TH-CHICAGO	Unknown	-	8,815	100
	12346491	SOUTH ST PAUL - 2ND AVE S - MARIE AVE	Unknown	-	7,530	120
	12346357	MENDOTA HTS - HWY 13 - WACHTER AVE	Unknown	-	911	5
St. Cloud	12342575	ST JOSEPH - 1ST AVE NE - CTY RD 75	1966	1	9,150	79
	12403875	SARTELL - MISSISSIPPI RIVER CROSSING	1973	8	1,700	-
	12249351	DELANO	Unknown	-	14,800	127
Southeast	12385504	WINONA - 3RD ST BTW GALE ST-MECHANIC ST	1974	9	8,100	127
	12354151	NORTHFIELD - FLORELLAS CT	1968	3	1,550	22
	12328936	FARIBAULT - 8TH ST SW	Unknown	-	5,320	48
	12345274	FARIBAULT - 7TH ST NW	1980	15	4,900	43
	12350531	FARIBAULT - 8TH ST SW, BOTSFORD, CARLTON	Unknown	-	3,000	49
Moorhead	12359542	MOORHEAD - REGAL ESTATES	Unknown	-	10,500	210
2016 DIMP Main and Service Replacements Total					**270,427**	**3,279**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (Docket No. G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in Docket No. E,G002/D-07-1528)

Note: Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

2017 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2017						
Area	**Work Order Number**	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot. Svc**
St. Paul	12294045	ROSEVILLE - FERNWOOD ST	1955	-	3,760	44
	12315892	ST PAUL - CASE AVE BTN EDGERTON-EARL	1979	14	11,300	177
	12328310	ST PAUL - HAGUE/SELBY	1978	13	6,745	128
	12326608	ST PAUL - EDMOND	Unknown	-	5,290	113
	N/A	ST PAUL - ST PETER, FORD 4TH	1963	-	4,200	62
	12320752	ST PAUL - ETNA-BIRMINGHAM-WINCHELL	1962	-	9,600	141
White Bear Lake	12317581	ARDEN HILLS - ARDEN VIEW DR	Unknown	-	2,300	34
	12320389	ARDEN HILLS - GLENPAUL AVE	1955	-	4,700	58
	12319969	MAHTOMEDI - GRIFFIN AVE	1968	3	3,200	39
	12092590	BAYPORT - 7TH ST	1964	-	1,000	11
Wyoming	12320014	FOREST LAKE - 11TH AVE SW (LAKE ST)	Unknown	-	2,100	25
	12320051	FOREST LAKE - 208TH-209TH ST	1969	4	4,000	47
	12320027	FOREST LAKE - IVERSON AVE	1967	2	3,700	53
	N/A	FOREST LAKE - HEATH AVE	1968	3	3,600	34
Newport	12352434	COTTAGE GROVE - IRONWOOD	1971	6	3,338	100
	12438126	ST PAUL - BURNS-RUTH	1955	-	11,715	147
	DE 522036	COTTAGE GROVE - HYDE	1961	-	3,710	41
	DE 521888	COTTAGE GROVE - PT DOUGLAS RD, IDEAL AVE	1961	-	4,735	56
	DE 521609	COTTAGE GROVE - IDEAL-85TH ST	1962	-	4,160	36
	DE 521021	MENDOTA HTS - BACHELOR-SUTTON-MARIE	1973	8	10,570	77
	DE 526906	INVER GROVE HTS - DAWN-UPPER 75TH-77TH	1971	6	5,160	89
	DE 519457	INVER GROVE HTS - CONROY CT	1972	7	5,400	142
St. Cloud	N/A	ST CLOUD - 16TH AVE - 3RD ST N	1972	7	4,100	26
	12412846	ST CLOUD - 44TH AVE N, APPOLLO BY VA	1972	7	2,500	10
Southeast	DE 525652	WINONA - 3RD ST BTW WINONA ST-LIBERTY ST	1968	3	8,500	154
	12320940	NORTHFIELD - WOODLEY ST E	1977	12	500	13
	12344771	NORTHFIELD - ARCHIBALD ST/ASTER	1981	16	3,500	55
	12356426	LAKE CITY - LAKEWOOD AVE	1972	7	4,250	79
	12360394	RED WING - SPRUCE/SOUTHWOOD	Unknown	-	6,000	86
	12356414	WINONA - 9TH/52ND	1977	12	3,500	42
	N/A	NORTHFIELD - EDWARDS LN	1968	3	1,660	42
	DE 525650	RED WING - BUSH ST - PLUM ST	1983	18	3,250	76
	N/A	RED WING - WRIGHT/FINRUD	1975	10	10,400	130
Moorhead	12410474	MOORHEAD-MOBILE MANOR-1224 15TH AVE. N	1972	7	1,260	38
	12422040	DILWORTH - 1ST AVE SE	1972	7	5,000	48
2017 DIMP Main and Service Replacements Total					**168,703**	**2,453**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

Note: Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

Calculation of Estimated Annual GUIC-Related Retirements for 2012-2025

2018 Mains and Service Replacements

NSP-MN Main & Services DIMP Replacement Projects 2018						
Area	Work Order Number	Description	Year Retired Main was Installed	Remaining Depreciable Service Life 1/1/2010 [1]	Total Design FT.	Tot. Svc
St. Paul	102002462	ROSEVILLE / CO RD 2 & LAKEVIEW / DIMP	Unknown	-	14,150	70
	101157888	RSV/OXFORD ST/ DIMP/ INSTALL 1200' 2" PE	Unknown	-	1,200	4
	101746906	ST PAUL - ISABELL / CONGRESS	1965	-	4,700	2
	101592642	STP/ 2018 DIMP / AREA N-UPP AFTON	1960	-	7,510	106
White Bear Lake/Wyoming	100382714	01432348 NO ST PAUL 18TH AVE INSTALL 560	Unknown	-	560	2
	101756642	MPW/Raditz Ave/ Install 3800' of 2"	1965	-	3,800	26
	100412206	MWD/ EDGERTON ST/ INSTALL 4200' OF 2" PE	1955	-	4,200	1
	101509812	BIR / 2018 DIMP / BIRCHWOOD AVE	1968	3	2,921	39
	101776492	DIMP OAK GERSHWIN AVE INST 1100' - 2" PE	1970	5	1,100	-
	101879289	DIMP OAK GRAFTON AVE INST 1600' 2" MAIN	1970	5	1,600	10
	102146268	DIMP OAK GRANADA AVE 4100' - 2" MAIN	1970	-	4,100	24
	101359567	Forest Lake / 2018 DIMP / HARROW AVE N	1969	4	1,900	7
	100441816	LTC/ EDGERTON ST/ DIMP	1968	3	5,000	29
	100441817	LTC/ LABORE RD/ DIMP	1969	4	5,400	33
	101756827	LTL / 2018 DIMP / EDGERTON N OF LITTLE C	1968	3	8,500	35
	101155888	LTL / GREENBRIER ST /DIMP/ 5100' of 2"	1970	5	5,400	42
	100920813	LTL-WESTWIND DR-DIMP-INSTALL 2700' 2" PE	1969	4	2,700	19
	101946663	MAPLEWOOD - ROSELAWN	1954	-	2,400	7
	101947593	MAPLEWOOD / COPE AVE	1957	-	3,500	32
	101947594	MAPLEWOOD / CRAIG PL	1959	-	5,700	44
	101834990	MAPLEWOOD / HOLLOWAY / DIMP	1955	-	3,500	28
	101947595	MAPLEWOOD / JACKSON ST	1956	-	4,800	36
	101692533	MPW / 2018 DIMP / MAYHILL - MINNEHAHA #4	1961	-	5,500	43
	101756635	MPW/ /ARCADE ST/DIMP/INSTALL 5000' OF 2"	1966	1	5,000	23
	101163818	MPW/ BEAUMONT ST/ DIMP/ INSTALL 1400' 2"	1955	-	1,400	16
	101876643	MPW/MARYLAND AVE/DIMP/ INSTALL 1900' 2"	1965	-	1,900	14
	101627154	MWD - ELM ST DIMP	1970	5	1,250	8
	100588988	NEW BRIGHTON / WINDSOR CT - PHASE 3	1967	2	1,850	57
	100439830	NO ST PAUL HILLTOP CT INSTALL	1969	-	2,700	27
	101833922	NORTH ST PAUL / 1ST AVE	1966	1	4,652	44
	102001637	NORTH ST PAUL / 4TH & MARGARET / DIMP	1953	-	4,500	-
	101834533	NORTH ST PAUL / IVY ST N	1970	5	1,048	30
	101524703	NSP / 2018 DIMP / COWERN-HOWARD	1969	4	2,300	28
	101693184	NSP / 2018 DIMP / NAVAJO RD	1958	-	2,300	27
	101693177	NSP / 2018 DIMP / SHOSHONE RD E	1958	-	2,500	25
	101784580	NSP / 2018 DIMP / SKILLMAN	1954	-	9,340	57
	101916855	NSP / 2018 DIMP / WEST SIDE OF IVY ST N	1970	5	800	-
	101919344	NSP / MARY JO LN	1955	-	4,750	37
	101508477	NWB /2018 DIMP / 10th AVE NW	1970	5	4,180	-
	101985751	SHOREVIEW / HODGSON / DIMP	1962	-	4,600	-
	101693170	SHV / 2018 DIMP / BRIGADOON DR	1968	3	2,500	44
	101496871	SHV / 2018 DIMP / MERCURY-WOODLAND	1967	2	3,840	17
	101582735	SHV / 2018 DIMP / SNAIL LK RD & JANSA	1962	-	7,354	12
	101383583	SLL/ OLIVE ST W/ RECON/ INS 2400' 2" PE	Unknown	-	2,350	23
	101960298	SLL/SYCAMORE ST W/ INSTALL 5000' 2" PE	1968	3	4,700	32
	101582727	WBL / 2018 DIMP / CLARENCE ST	1968	3	4,163	-
	101688133	WHITE BEAR LAKE - STILLWATER ST-BALD-GARDEN	1961	-	14,049	89
	101660586	WHITE BEAR LAKE / EAST COUNTY LINE	1961	-	2,175	17
	101556528	WHITE BEAR LAKE / SOUTHWOOD	1968	3	3,461	35
	101832776	WHITE BEAR TOWNSHIP / BELLAIRE / DIMP	1961	-	7,000	38
	101838144	FOREST LAKE / FONDANT / DIMP	1970	5	5,000	31
	101463010	SHV / 2018 DIMP / VIRGINIA AVE	1968	3	1,800	-
Newport	101547248	COTTAGE GROVE - IDEAL-85TH ST DIMP	1961	-	4,160	35
	101876838	CTG / 2018 DIMP / HAMLET-HALLMARK-HALE	1959	-	6,950	83
	101478741	CTG / DIMP / HEARTHSIDE RD / RNW MAIN	1964	-	2,300	14
	101587426	IGH - CONROY CT DIMP	1972	7	5,385	-
	101886606	IGH / 2018 DIMP / DAWN AVE - UPPER 75TH	1955	-	4,300	-
	102028709	MEH / 2018 DIMP / WINSTON CT-DOWNING	1968	3	4,600	20
	101692530	MPW / 2018 DIMP / CRESTVIEW-HIGHWOOD	1969	4	11,000	61
	101685475	MEH / 2018 DIMP / MARIE-OVERLOOK	1969	4	5,700	41
	101692534	MPW / 2018 DIMP / MAYHILL-UPP AFTON (Metz)	1959	-	3,827	8
	101417261	SPP / DIMP / SUMMIT AVE / RENEW MAIN	Unknown	-	3,900	36
	101697233	WSP / 2018 DIMP / MENDOTA RD W	1969	4	2,940	10
St Cloud	101379226	SCL / 2018 DIMP / KINGS WAY	Unknown	-	1,600	16
	101714442	ST CLOUD / 6TH ST / 11TH AVE / 10TH AVE / DIMP	Unknown	-	1,630	12
	101579939	ST CLOUD / PROSPER DR-PROGRESS RD	1970	5	2,870	3
	101602512	STC - 4TH AVE N / DIMP	1970	5	5,055	39
Southeast	101804538	RDW / 2018 DIMP / 21ST ST	1960	-	1,300	16
	101802475	RDW / 2018 DIMP / CENTRAL PARK-18TH ST	1955	-	1,600	17
	101711329	RDW / 2018 DIMP / FINRID-WRIGHT	1971	6	10,400	105
	101794997	RED WING 189784 - 9TH ST	1955	-	850	2
	101728125	WINONA / DIMP / 107558 - E 7TH ST	1964	-	3,500	46
	101591201	WINONA / DIMP / 107603 - 7TH ST W	1966	1	5,800	23
	101780666	WINONA 107542 - E 10TH ST	1965	-	3,000	37
	101889468	WINONA 107587 - E 9TH ST	1961	-	1,400	11
	101913103	WNA / 2018 DIMP / 44TH AVE-VARIOUS	1961	-	4,300	34
	101544613	WNA / 2018 DIMP / COLLEGE VIEW-PARK	1960	-	2,515	18
	101692535	WNA / 2018 DIMP / CONRAD - WINCREST	1961	-	6,860	44
	101747565	WNA / 2018 DIMP / KNOLLWOOD LN	1969	4	1,950	4
	101903273	WNA / 2018 DIMP / W 9TH-ORRIN-WAYNE	1960	-	3,400	21
Moorhead	101490329	MHD / 2018 DIMP / CEDAR LANE	1970	5	4,215	34
	101483693	MHD / 2018 DIMP/Cedar-BIRCH	1970	5	4,000	30
2018 DIMP Main and Service Replacements Total					**334,910**	**2,190**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

Note: Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

2019 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2019					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Moorhead	MHD / 2019 DIMP / 11TH & 12TH St S	1961	-	8,341	40
Newport	CTG / 2019 DIMP / HYDE AVE S	1961	-	3,834	81
	CTG / 2019 DIMP / E PT DOUGLAS - IDEAL	1961	-	4,723	-
	MEH / 2019 DIMP / LANSFORD - STANWICH	1967	2	6,562	38
	MEH / 2019 DIMP / FREMONT - CHIPPEWA	1954	-	8,814	77
Northwest	MHD / 2019 DIMP / 19TH ST S - 24TH AVE S	1967	2	9,743	87
Southeast	LKC / 2019 DIMP / 10TH ST - W IOWA	1972	7	2,737	22
	LKC / 2019 DIMP / LILAC LN_PINE GROVE LN	1971	6	8,012	67
	WAB/DIMP/INDUSTRIAL CT & HWY 61	1970	5	4,814	16
	WNA / DIMP / EDGEWOOD RD	1965	-	3,656	39
	WNA / DIMP / E 8TH ST-BRIDGE	1960	-	4,658	51
	WNA / 2019 DIMP / SUNSET-VARIOUS	1960	-	17,135	143
	WNA / DIMP / LAIRD ST & E.BROADWAY	1960	-	475	1
	WNA / DIMP / W 6TH ST 54TH AVE	1963	-	3,722	39
	WNA / DIMP / HILBERT ST & W.6TH ST	1948	-	7,679	33
St. Paul	RSV / DIMP / CO RD C2 - LAKEVIEW	1954	-	3,551	-
	RSV / 2019 DIMP / LEXINGTON - DIONNE	1954	-	2,136	46
	TP / 2019 DIMP / BATTLE CREEK 1	1960	-	5,005	47
	STP / 2019 DIMP / BATTLE CREEK 2	1960	-	15,593	142
White Bear Lake	MWP / DIMP / CENTURY AVE	1962	-	4,097	20
	NSP / 2019 DIMP / INDIAN WAY - 2ND ST N	1959	-	4,197	54
	MPW/ Keller Pkwy/ 1120' 2"" PE - DIMP	1969	4	1,174	1
	SHV / DIMP / HODGSON RD	1964	-	5,390	17
	SHV / 2019 DIMP / CHURCHILL - HARRIET	1963	-	3,034	-
	SHV / 2019 DIMP / KENT ST - HARRIET AVE	1972	7	6,837	36
	SHV / 2019 DIMP / INGERSON RD	1955	-	6,257	67
	VDH / 2019 DIMP / MC MENEMY	1973	8	8,625	36
2019 DIMP Main and Service Replacements - Non-Urban Project Subtotal				**160,801**	**1,200**

Northwest	Downtown St Cloud LPS Retirement Prj	1972	7	5,487	-
Southeast	RDW/ DIMP/ W MAIN - 3RD ST.	1958	-	2,584	56
St. Paul	STP / 2019 DIMP / CONGRESS-ISABEL	1965	-	6,667	42
	STP / 2019 DIMP / ROBIE ST E	1971	6	3,066	43
	STP/ 2019 DIMP/ Flandrau St	1953	-	2,188	1
	STP / 2019 DIMP / ST. PETER STREET	1951	-	3,801	12
	STP / 2019 DIMP / LOWERTOWN	1956	-	2,833	1
White Bear Lake	LTL / DIMP / EDGERTON N OF LITTLE C	1965	-	2,227	-
	NWB / 2019 DIMP / BRIGHTON SQ	1968	3	2,499	60
2019 DIMP Main and Service Replacements - Urban Project Subtotal				**31,352**	**215**

2019 DIMP Main and Service Replacements Total			**192,153**	**1,415**

[1] Remaining Service Life at start of 2010 Test Year in 2010 Gas Rate Case (G002/GR-09-1153). Based on Gas Distribution Main Depreciation Average Service Life of 45 Years (Approved in E,G002/D-07-1528)

Note: Please note that replaced assets shown in our retirement and net book value estimate (Pages 2-18) do not directly correlate to this listing. See our Petition for an explanation of our retirement process.

Calculation of Estimated Annual
GUIC-Related Retirements for 2012-2025

2020 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2020					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Grand Forks	Grand Forks - Gateway Dr NE (MN Side)	1970	5	2502	0
Moorhead	Moorhead - 30th Ave S	1970	5	4312	0
	Moorhead - 2nd Ave/6th Street	1965	-	5564	27
	Moorhead - Appletree Ln	1971	6	4252	27
	Moorhead - Rensvold Blvd	1973	8	4788	22
	Moorhead - Maple Lane	1970	5	4166	37
Newport	122935 - Cottage Grove Grospoint	1958	-	2931	35
	122943 - Cottage Grove - Grenadier	1958	-	2779	32
	122954 - Cottage Grove - Greystone	1958	-	3102	35
	Newport - 377436 5th Ave & 3rd Ave	1958	-	8836	47
	South St. Paul - Wentworth Ave	1955	-	678	0
Southeast	Bayport - 3rd Street	1961	-	3886	24
	Faribault 109442 - Irving Ave	1971	6	3512	36
	Faribault - Division St W	Unknown	-	240	1
	Goodview - 44th Ave S Phase 2	1961	-	9628	96
	117747 - Lake City - Garden and Prarie	1975	10	7798	48
	117698 - Lake City - Camp Lakeview Rd	1965	-	3922	5
	Lake City - South 7th Street	1966	1	8379	79
	Lake City - Woodburn Street	1964	-	13871	72
	Lake City - Washington St	1964	-	8125	35
	Northfield - 321 ST W	1967	2	5378	26
	Red Wing 189276 - Woodland Dr	1969	4	5077	39
	195249 - Red Wing - Maple 1	1959	-	8758	84
	Red Wing 189336 - Reding Ave	1968	3	6067	26
	195287 Maple St 2 - Red Wing	1957	-	16280	145
	189424 - Hawthorne St Red Wing	1954	-	7446	81
	Winona - Goodview Phase 1	1961	-	17259	117
	Winona - Kansas & 3rd 98289	1960	-	1672	7
	Winona - Bundy Blvd	Unknown	-	1535	1
	Winona - Carimona St	1960	-	9094	80
St. Cloud	Sauk Rapids - Hwy 23 Renew	Unknown	-	3040	11
	215835 34th Ave N St. Cloud	1964	-	7148	54
	215817 35th Ave N St. Cloud	1965	-	5262	61
	198334 - 11th St S St Cloud	1967	2	2456	35
	Westminster Ave, Watertown 356007	1965	-	7289	122
	Watertown - Angel Ave	1965	-	10401	95
St. Paul	Falcon Heights - Tatum St	1956	-	2557	24
	Falcon Heights - Arona St	1957	-	4186	43
	Roseville - Victoria Street	Unknown	-	2559	12
	Roseville - Roseville Shopping Ctr	1969	4	426	0
	Roseville - Perimeter Drive	1971	6	3570	9
	St. Paul - South of Upper Afton Phase 1	1960	-	10454	124
	St. Paul - South of Upper Afton Phase 2	1960	-	7238	93
	St. Paul - Valley View/Highwood	1967	2	4178	29
	St. Paul - Cypress & Reaney	1960	-	8478	63
	St. Paul - Highwood Ave	1967	2	2279	9
	St. Paul - Hampden	1954	-	17	0
	St. Paul - 10th St. W	1951	-	1757	0
White Bear Lake	Dellwood - Old Hwy 8	1965	-	158	0
	Lake Elmo - 31st/Jamley/Janero	1967	2	6568	34
	336199 - Lake Elmo - Stillwater Blvd.	1967	2	3746	13
	MahtomediI - Neptune	1962	-	1524	7
	18354 - Maplewood - Larpenteur Ave E	1954	-	2389	17
	Maplewood - County B E	1968	3	4552	16
	9th Avenue New Brighton	1957	-	4865	70
	12th Avenue New Brighton	1957	-	3075	26
	365726 - 10th Avenue New Brighton	1957	-	3570	39
	11th Avenue New Brighton	1957	-	3780	47
	347751 Poppyseed Drive New Brighton	1969	4	8015	71
	North Oaks - Spring Farm Lane	1965	-	8852	30
	North Oaks - Mallard Rd	1969	4	535	0
	North St. Paul - 15th Ave E	1953	-	5942	46
	North St. Paul - Oakhill Pl	Unknown	-	600	1
	North St. Paul - Division St. Phase 1	1953	-	7184	49
	North St. Paul - Division St. Phase 2	1953	-	17508	206
	North St. Paul - 11th Ave E	1968	3	2045	8
	Oakdale - 52nd Street North	1963	-	3711	20
	Shoreview - Victoria St	1959	-	4415	17
	Shoreview - Ingerson Rd	1955	-	6257	4
	Shoreview - Pinewood Dr	1970	5	9153	54
	Shoreview - Brigadoon Dr	1969	4	7737	89
	White Bear Township - South Shore Blvd - 2020	1970	5	9823	56
	White Bear Lake - Lincoln Avenue	1963	-	2467	22
	White Bear Lake - Bellaire Ave	Unkown	-	268	0
Wyoming	Forest Lake - 210th St N	1967	2	2872	16
	Wyoming - E Viking Blvd	1971	6	7175	78
	Wyoming - Forest Blvd N	1966	1	8646	20
2020 DIMP Main and Service Replacements Total				**412,564**	**3,104**

Calculation of Estimated Annual
GUIC-Related Retirements for 2012-2025

2021 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2021					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Grand Forks	BW/EGF/GD/DIMP/3rd ST NW&3rd Ave NW	Unknown	-	2,597	15
Moorhead	Moorhead - S 8th Street	1965	-	1,020	4
	Moorhead - Concordia College	1962	-	1,781	3
	Moorhead - S 30th Ave	1973	8	14,295	20
Newport	Concord St - St. Paul	1967	2	12,282	30
	West St. Paul - Moreland Avenue	Unknown	-	3,034	8
	South St. Paul - Marie Ave	Unknown	-	5,065	23
Northwest	St. Cloud - 14th Ave NE	Unknown	-	680	11
	St. Cloud - 6th Ave S	1979	14	2,151	17
	St. Cloud - Rusan Street	1969	4	5,447	10
	St. Cloud - Sherwood Mobile Home Park	1968	3	9,212	109
	W. St. Germain St. - St. Cloud	1977	12	5,022	20
St. Paul	Roseville - Terminal Road	1966	1	3,221	8
	County B 2 - DIMP/RECON	1967	2	3,071	15
	Cleveland Ave N	Unknown	-	3,907	20
	St. Paul - Churchill	1920	-	8,678	100
	STP 139651 - COMO Ave	1955	-	2,327	14
Southeast	Woodland Dr & Greenleaf Rd Faribault	1971	6	7,054	27
	Faribault - Downtown	1959	-	7,533	108
	Lincoln Ave NW & 2nd St NW Farib	1971	6	7,457	72
	Goodview - 54th	1961	-	5,250	13
	Lake City - N High St Ph 1	1964	-	2,783	16
	Old W Main & Jackson - Red Wing	1960	-	1,094	3
	West Ave & 9th St	1955	-	51	0
	Old Zumbrota St & Guernsey Ln - Red Wing	1977	12	465	8
	Red Wing - Levee Road	1955	-	1,269	0
	Red Wing - W 5th St	1967	2	3,169	24
	Winona - Cottonwood Dr	1977	12	1,247	6
	Winona - Marian & Gale	1965	-	5,014	73
	Winona - Industrial Park Rd	1965	-	5,749	11
	Winona - Frontenac Dr & Menard Rd	1975	10	2,854	7
	Lion's Park - Winona	Unknown	-	195	1
White Bear Lake	Arden Hills - Lexington Ave	1965	-	5,794	24
	Little Canada - S Owasso Blvd	1961	-	2,519	6
	Little Canada - Country Drive	1972	7	9,262	11
	Maplewood - Kohlman Avenue	1970	5	9,060	28
	Arden Hills - Red Fox Rd	1968	3	3,767	8
	Mahtomedi - Wildwood Road	1962	-	2,232	18
	North Oaks - West Shore Rd	1969	4	10,320	26
	New Brighton 7th St NW	1959	-	209	0
	Windsor Court - New Brighton	1967	2	3,744	82
	HWY 36 - Castle Ave	1970	5	3,626	9
	Lexington & Cannon	1961	-	2,600	2
	Shoreview - Rice/Marie Street	1967	2	1,693	10
	Lakewood Ave - WBL	1959	-	14,168	112
Wyoming	Forest Lake - Harrow Ave	1968	3	5,172	0
	Forest Ave - Stacy	1970	5	1,031	10
	Forest Lake - Lake St & 4th Ave SW	1961	-	3,375	11
	Broadway St - Lindstrom	1966	1	2,738	23
2021 DIMP Main and Service Replacements Total				**216,284**	**1,176**

Calculation of Estimated Annual
GUIC-Related Retirements for 2012-2025

2022 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2022					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Grand Forks	EGF - 17th St NW and 8th Ave NW	Unknown	-	4,735	11
Moorhead	Moorhead - 5th and 4th St S	1961	-	25,817	108
	Moorhead - 16th St N	1962	-	3,100	20
	Moorhead Center Mall	1972	7	1,985	3
	Moorhead - Highway 75	1961	-	7,250	16
Newport	IGH -Cahill Ave & Carleda Way	Unknown	-	4,875	38
	IGH - Maple Park Drive & Dodd	1966	1	3,820	29
	IGH - S Robert Trail	1970	5	6,352	7
	Oakdale - Pedersen St & Old Hudson St	1963	-	4,833	16
	South Saint Paul - 4th Ave	1973	8	3,000	32
Northwest	Delano - 3rd St N	1966	1	3,408	29
	Delano - Highlands Ridge	Unknown	-	5,801	37
	Watertown - Hillside Dr	Unknown	-	400	11
	Watertown - White St	Unknown	-	1,700	5
St. Paul	Roseville - Cty B2 & Lexington	1954	-	8,532	84
	St. Paul - Prior Ave and University Ave	Unknown	-	3,300	6
	St. Paul - Wabasha St and 4th St	1967	2	1,120	0
	St. Paul - Larpenteur & Jackson	1959	-	6,708	30
Southeast	Faribault - Greenwood Pl Apartments	1956	-	439	2
	Faribault - Greenwood Place	1968	3	4,264	41
	Northfield - Woodley St W	1971	6	2,281	7
	Lake City - Oak St	1965	-	2,583	21
	Lake City - N 6th St	1965	-	3,653	26
	Lake City - High Street Ph 2	1955	-	3,180	15
	Lake City - Oak St - Additional Work	1965	-	1,492	9
	Red Wing - Featherstone Rd	1972	7	2,056	4
	Winona - Theurer Blvd, Revision A	Unknown	-	6,858	2
	Winona - Frontenac Dr & Menard Rd	1975	10	2,854	7
White Bear Lake	North Shore Trail	1965	-	10,190	74
	Little Canada - Rose & McMenemy	1965	-	5,352	34
	Old Wildwood Rd	1962	-	3,750	8
	McMenemy Street	1965	-	10,674	52
	New Brighton – 7th St NW	1959	-	5,235	45
	North Oaks - Pleasant Lake Rd	1969	4	1,000	0
	Mounds View - County Rd I	1967	2	4,000	19
	Lexington & Cannon Phase 2	1961	-	10,329	83
	Victoria St (former Cty Rd E) - Shoreview	1970	5	4,780	14
	Birch Knoll Dr	1965	-	2,362	22
	White Bear - Martin Way	1961	-	9,477	76
Wyoming	Lindstrom - Pleasant Ave	1965	-	4,500	28
	Lindstrom - Newell Ave	1966	1	4,560	41
	Wyoming - E Vikings Blvd	1967	2	7,675	37
2022 DIMP Main and Service Replacements Total				**210,280**	**1,149**

Calculation of Estimated Annual
GUIC-Related Retirements for 2012-2025

2023 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2023					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Moorhead	12th Ave & 20th St S	1961	-	3,632	27
	6th St & 16th Ave S	1962	-	5,025	21
	27th Ave & 18th St S	1970	5	7,029	40
	Romkey & Park	1962	-	7,834	72
	20th St N	1961	-	6,541	92
Newport	Oakdale Ave	1965	-	11,020	0
	Woodlane Dr & Valley Creek Rd	1966	1	6,806	8
	Thompson & Humboldt	1969	4	3,681	20
	Marie & Humboldt	1972	7	4,596	46
	Eagle Ridge	1971	6	6,221	72
Northwest	1st St S	1969	4	10,839	44
	3rd Street N & 6th Ave N	1970	5	2,564	1
	14th St S & 9th Ave S	1968	3	2,144	15
	Cloverleaf Trailer	Unknown	-	10,948	155
	3rd St	1966	1	15,040	113
Southeast	7th St NW	1954	-	3,457	33
	Lyndale Ave N	1957	-	7,790	24
	2nd St NW	1956	-	5,718	28
	Prairie Ave SW	1952	-	21,381	231
	Maple Street - Northfield	1950	-	2,742	21
	Cannon River Ave	Unknown	-	3,868	11
	Grandview Mobile Home Park	1965	-	8,249	98
	E 2nd St & Franklin St	1960	-	3,375	29
Rice Street	Water Street	1961	-	5,546	12
	Arlington Ave	1951	-	750	0
	W 7th and Homer	1964	-	6,628	9
	Milton St N & Pierce Butler Rte	1950	-	1,813	8
	McKnight Rd (Phase 1)	1972	7	6,974	51
	McKnight Rd (Phase 2)	1968	3	9,757	54
	McKnight Rd (Phase 3)	1978	13	4,641	36
	Cleveland Ave N	Unknown	-	4,088	5
White Bear Lake	Lakewood Dr	1958	-	3,971	33
	Gary Pl	1953	-	1,830	16
	Old Hwy 8 (Part 1)	1950	-	8,695	17
	County Rd E	1965	-	5,732	28
	Mooney Dr	1974	9	4,097	78
	10th St N	1968	3	3,021	15
	Beacon St	1956	-	3,596	35
	Hall St N	1976	11	5,482	36
Wyoming	1st Street SE	1960	-	2,824	18
	Sunrise Estates	1977	12	7,863	128
2023 DIMP Main and Service Replacements Total				**247,808**	**1,780**

Calculation of Estimated Annual
GUIC-Related Retirements for 2012-2025

2024 Mains and Services Replacements

NSP-MN Main & Services DIMP Replacement Projects 2024					
Area	**Description**	**Year Retired Main was Installed**	**Remaining Depreciable Service Life 1/1/2010 [1]**	**Total Design FT.**	**Tot.Svc**
Grand Forks	EGF//DIMP/BUS HWY 2 ACS - BERTS 4"	1974	9	8,400	10
	EGF/DIMP/2ND AVE NE - ACS 8" & 6"	1974	9	5,950	7
Moorhead	14th St N - Moorhead	1958	-	4,080	73
Newport	80th Street & Jamaica Ave	1971	6	5,050	26
	Grange Blvd & Hadley Ave S	Unknown	-	1,180	1
	Cahill Ave - IGH	1971	6	4,200	20
	Livingston Ave & Wood St	1971	6	3,400	61
	8th Ave & 3rd St	1959	-	10,662	157
	Broadway Ave & Pleasant Ave	1966	1	810	13
	Dixon Dr & Gary Dr	1963	-	2,800	59
	Oakdale Ave - West St. Paul	1965	-	8,800	27
	Kopp Dr & Sperl St	1971	6	5,500	65
Northwest	Delano - 3rd St N	1966	1	29,040	178
	Jefferson Ave & Stevens St	1960	-	5,600	74
	3rd Street N & 6th Ave N	1970	5	3,202	21
	Hwy 10 - St. Cloud	1971	6	-	1
	3rd Street N - Waite Park	1961	-	5,650	42
Southeast	W 3rd Street - Red Wing	1954	-	8,585	38
	N Service Dr & Tyler Rd N (Grade 2 leak)	1964	-	2,800	10
	5th Street W & Pelzer St	1959	-	6,714	258
	E 2nd St & Franklin St	1960	-	3,650	45
	Gilmore Ave & W Sarnia St	1966	1	4,600	56
	Roberds Lake BLVD & 180th St	1972	7	4,700	43
	Wilson Ave & 4th St NW	1981	16	750	23
	Jefferson Rd - Northfield	1980	15	1,400	51
	Fremont St E & Nevada St	1968	3	2,500	33
Rice Street	Fulham St & Roselawn Ave W	1966	1	1,800	19
	Cleveland Ave & Oakcrest Ave	1967	2	2,499	29
	Larpenteur Ave W - Roseville	1954	-	2,320	10
	Long Lake Rd & Ct Rd C2	1969	4	5,459	19
	Saint Paul - Snelling & Concordia	Unknown	-	2,750	44
	Saint Paul - Water Street	1961	-	6,150	28
	Edgerton & Wheelock	1927	-	1,400	12
	Hampden Ave - St. Paul	1954	-	4,625	59
	Payne Ave & Wells St	1980	15	2,480	41
	Wabash Ave - St. Paul	1974	9	300	1
	Wabash Ave - St. Paul (Casings)	1970	5	1,950	10
White Bear Lake	Innovation Way (Fernwood St)	1968	3	1,900	3
	Century & Stillwater	1972	7	3,750	26
	E Shore Drive - Maplewood	1965	-	1,800	14
	Edgerton St - Maplewood - 12"	1977	12	2,000	0
	Phalen Pl - Maplewood	1955	-	125	4
	Cleveland Ave & 2nd St SE	1970	5	2,028	30
	Lakeside MHP - New Brighton	1974	9	6,042	134
	New Brighton - County E (old hwy 8 part 2)	1965	-	9,415	123
	Brookside MHP - Shoreview	1976	11	7,918	227
	Rice St & Rustic Pl	1963	-	1,765	1
	3rd St & Krech Ave - Phase 1	1966	1	4,900	93
	3rd St & Krech Ave - Phase 2	1966	1	1,850	40
	Chatham & Chippenham Lane	1967	2	700	9
Wyoming	1st ST NW - Forest Lake 8in	1968	3	4,100	25
	Interlachen Road - Chisago City	1968	3	3,600	45
2024 DIMP Main and Service Replacements Total				**223,650**	**2,438**

TIMP and DIMP Operating and Maintenance Expense 2023-2029

	2023 Actual	2024 Mixed	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
TIMP Projects							
NSPM Transmission Pipeline Assessments O&M	$ 520,632	$ 1,177,273	$ 602,000	$ 779,000	$ 656,000	$ 858,000	$ 875,160
State of Minnesota Load Dispatch Jurisdictional Allocator	87.99%	88.18%	87.86%	87.72%	87.78%	87.69%	87.32%
TIMP O&M allocated to MN Jurisdiction	**$ 458,078**	**$ 1,038,126**	**$ 528,899**	**$ 683,309**	**$ 575,835**	**$ 752,362**	**$ 764,168**
DIMP Projects							
DIMP O&M direct assigned to MN Jurisdiction	$ 246,375	$ 412,602	$ 1,528,333	$ 1,620,000	$ 1,602,000	$ 1,666,080	$ 1,727,523
Total Operations & Maintenance Expenses	**$ 704,453**	**$ 1,450,728**	**$ 2,057,232**	**$ 2,303,309**	**$ 2,177,835**	**$ 2,418,442**	**$ 2,491,691**

Universal Inputs

	2025
Cap Structure (Last Authorized)	
Long Term Debt %	46.89%
Long Term Debt Cost	4.13%
Short Term Debt %	0.61%
Short Term Debt Cost	0.94%
Weighted Cost of Debt	1.94%
Common Stock %	52.50%
Common Stock Cost	9.57%
Weighted Cost of Equity	5.02%
Rate of Return	6.97%
Tax Rates	
Income Tax Rates	
State Income Tax Rate	9.80%
Federal Income Tax Rate	21.00%
Composite Income Tax Rate	
State Composite Income Tax Rate	28.742%
Company Composite Income Tax Rate	28.032%
Property Tax Rate	1.31%
Book Depreciation Lives	
Transmission	59.07
Distribution	38.29
Software	4.77
Net Salvage %	
Transmission	-15.00%
Distribution	-22.85%
Software	-
Book Depreciation Rates	
Transmission	1.69%
Distribution	2.61%
Software	20.97%

*Note: Book Depreciation Rates reflect Average Remaining Life

Magnitude of GUIC Rider in Relation to Last Approved Rate Case

" Minn. Stat. § 216B.1635 Subd. 3 (VII) magnitude of GUIC in relation to gas utility's rate base revenue approved by the Commission in gas utility's most recent general rate case, exclusive of gas purchase costs and transportation charges "

" Minn. Stat. § 216B.1635 Subd. 3 (VIII) magnitude of GUIC in relation to gas utility's capital expenditures since its most recent general rate case"

2022 TY Minnesota Gas Rate Case, Cost of Service Study - Docket No. G002/GR-21-678
($000s)

	2022 Test Year	
Operating Revenues		
Retail	$ 801,070	Fn 1
Operating Expenses:		
Purchased Gas	$ 558,249	
Base Revenue, Net of Gas Purchase Costs & Transportation Charges	$ 242,821	[A]
Capital Expenditures (CWIP)	$ 54,299	[B]

Proposed Gas Utility Infrastructure Costs (GUIC) Rider
(Dollars in Thousands)

	2024	2025		
Revenue Requirement Forecast	$ 16,663	$ 27,191	[C] Fn 2	29300
% of GUIC Revenue as Compared to Base Revenue As settled in Docket G-002/GR-21-678 (2022 TY)	6.86%	11.20%	= [C] / [A]	0.12
Capital Expenditures Forecast	$ 59,357	$ 66,791	[D]	
% of GUIC Capital Expenditures as Compared to Expenditures As settled in Docket G-002/GR-21-678 (2022 TY)	109.32%	123.01%	= [D] / [B]	

Notes

Fn 1 See Compliance Filing in Docket No. G002/GR-21-678, Schedule 01B Cost of Service Summary, page 1, Line No. 45

Fn 2 Reflects forecasted revenue recovery for gas costs eligible for rider recovery under Minnesota 2013 Statute § 216B.1635 Recovery of Gas Utility Infrastructure Costs, including:
(a) revenue requirements associated with new gas utility infrastructure projects, and
(b) deferred costs include implementation of the inspection and remediation of sewer/natural gas line conflicts approved in Docket No. G002/M-10-422 and costs to comply with gas pipeline safety programs approved in Docket No. G002/M-12-248

Annual Revenue Requimrent Tracker Summary for 2023-2029

	2023 Actual	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast
Operations & Maintenance Expenses							
TIMP	$ 458,078	$ 1,038,126	$ 528,899	$ 683,309	$ 575,835	$ 752,362	$ 764,168
DIMP	246,375	412,602	1,528,333	1,620,000	1,602,000	1,666,080	1,727,523
Total Operations & Maintenance Expenses	$ 704,453	$ 1,450,728	$ 2,057,232	$ 2,303,309	$ 2,177,835	$ 2,418,442	$ 2,491,691
Capital-Related Revenue Requirements							
TIMP	$ 8,830,427	$ 2,497,359	$ 3,377,664	$ 5,130,790	$ 5,630,462	$ 5,945,033	$ 6,140,459
DIMP	18,874,360	11,248,768	15,003,051	18,212,042	21,673,240	25,142,466	28,625,261
Mandated Relocates	4,091,746	6,269,690	9,417,567	11,286,223	13,322,575	15,299,464	17,285,671
Total Capital-Related Revenue Requirements	$ 31,796,533	$ 20,015,818	$ 27,798,283	$ 34,629,056	$ 40,626,277	$ 46,386,962	$ 52,051,391
Regulatory Treatment							
Other Disallowances	$ (6,315,130)	$ (5,094,823)	$ (7,125,307)	$ (9,144,966)	$ (11,064,700)	$ (12,932,445)	$ (14,753,894)
Revenue Requirement Subtotal	**$ 26,185,856**	**$ 16,371,723**	**$ 22,730,208**	**$ 27,787,399**	**$ 31,739,412**	**$ 35,872,959**	**$ 39,789,188**
Prior Year Carryover	2,972,952	4,751,786	4,460,814	0	0	0	0
Revenue Requirement (RR)	**$ 29,158,808**	**$ 21,123,510**	**$ 27,191,021**	**$ 27,787,399**	**$ 31,739,412**	**$ 35,872,959**	**$ 39,789,188**
Revenue Collections (RC)	$ 24,407,022	$ 16,662,696	$ 27,191,021	$ 27,787,399	$ 31,739,412	$ 35,872,959	$ 39,789,188
Carryover Balance (RR - RC)	$ 4,751,786	$ 4,460,814	$ -	$ -	$ -	$ -	$ -

Monthly Revenue Requirement Tracker Summary for 2023

	Jan-23 Actual	Feb-23 Actual	Mar-23 Actual	Apr-23 Actual	May-23 Actual	Jun-23 Actual	Jul-23 Actual	Aug-23 Actual	Sep-23 Actual	Oct-23 Actual	Nov-23 Actual	Dec-23 Actual	2023 Annual
Operations & Maintenance Expenses													
TIMP	$ 10,552	$ 529	$ 5,275	$ 192,377	$ 42,633	$ 119,671	$ 20,379	$ 8,074	$ 18,715	$ 4,766	$ 21,036	$ 14,070	$ 458,078
DIMP	96,387	-	3,280	671	1,155	56,719	(5,568)	35,755	52,824	5,152	-	-	246,375
Total Operations & Maintenance Expenses	$ 106,939	$ 529	$ 8,555	$ 193,048	$ 43,788	$ 176,390	$ 14,811	$ 43,829	$ 71,539	$ 9,918	$ 21,036	$ 14,070	$ 704,453
Capital-Related Revenue Requirements													
TIMP	$ 1,129,043	$ 1,128,610	$ 1,124,071	$ 1,115,078	$ 1,113,360	$ 1,163,981	$ 1,154,545	$ 154,395	$ 181,771	$ 190,241	$ 178,586	$ 196,747	$ 8,830,427
DIMP	2,234,020	2,237,343	2,239,390	2,224,955	2,225,117	2,175,041	2,092,812	585,955	638,676	713,547	710,842	796,662	18,874,360
Mandated Relocates	351,621	366,441	366,031	356,158	342,367	231,596	433,508	279,746	244,248	241,757	430,119	448,153	4,091,746
Total Capital-Related Revenue Requirements	$ 3,714,684	$ 3,732,395	$ 3,729,492	$ 3,696,192	$ 3,680,845	$ 3,570,619	$ 3,680,864	$ 1,020,096	$ 1,064,694	$ 1,145,544	$ 1,319,547	$ 1,441,561	$ 31,796,533
Regulatory Treatment	$ (1,836,413)	$ (472,012)	$ (474,469)	$ (486,088)	$ (513,084)	$ (543,447)	$ (564,569)	$ (259,133)	$ (274,913)	$ (287,841)	$ (297,980)	$ (305,181)	$ (6,315,130)
Revenue Requirement Subtotal	**$ 1,985,211**	**$ 3,260,912**	**$ 3,263,578**	**$ 3,403,151**	**$ 3,211,549**	**$ 3,203,562**	**$ 3,131,106**	**$ 804,792**	**$ 861,321**	**$ 867,622**	**$ 1,042,603**	**$ 1,150,450**	**$ 26,185,856**

Prior Year Carryover Balance	$ 2,972,952
Total Revenue Requirements	$ 29,158,808
Revenue Collections (Mar 24 - Feb 25)	$ 24,407,022
Current Year Carryover Balance	$ 4,751,786

Monthly Revenue Requirement Tracker Summary for 2024

	Jan-24 Actual	Feb-24 Actual	Mar-24 Actual	Apr-24 Actual	May-24 Actual	Jun-24 Actual	Jul-24 Forecast	Aug-24 Forecast	Sep-24 Forecast	Oct-24 Forecast	Nov-24 Forecast	Dec-24 Forecast	2024 Annual
Operations & Maintenance Expenses													
TIMP	$ 1,197	$ -	$ 14,785	$ 297,683	$ 18,492	$ 133,322	$ 253,578	$ 92,384	$ 89,121	$ 40,622	$ 82,420	$ 14,521	$ 1,038,126
DIMP	-	-	-	150	163,040	54,412	32,500	32,500	32,500	32,500	32,500	32,500	412,602
Total Operations & Maintenance Expenses	$ 1,197	$ -	$ 14,785	$ 297,833	$ 181,532	$ 187,734	$ 286,078	$ 124,884	$ 121,621	$ 73,122	$ 114,920	$ 47,021	$ 1,450,728
Capital-Related Revenue Requirements													
TIMP	$ 210,611	$ 209,332	$ 209,984	$ 209,177	$ 209,268	$ 205,606	$ 200,618	$ 176,473	$ 178,317	$ 210,112	$ 236,387	$ 241,475	$ 2,497,359
DIMP	862,753	868,876	879,353	852,962	623,385	867,958	894,209	980,528	1,025,523	1,081,353	1,130,314	1,181,552	11,248,768
Mandated Relocates	516,701	467,001	477,262	447,278	385,849	465,389	388,135	467,723	582,029	678,973	694,675	698,674	6,269,690
Total Capital-Related Revenue Requirements	$ 1,590,065	$ 1,545,209	$ 1,566,600	$ 1,509,417	$ 1,218,502	$ 1,538,954	$ 1,482,963	$ 1,624,724	$ 1,785,869	$ 1,970,438	$ 2,061,376	$ 2,121,701	$ 20,015,818
Regulatory Treatment	$ (757,971)	$ (312,087)	$ (314,881)	$ (326,808)	$ (354,080)	$ (384,722)	$ (406,136)	$ (422,572)	$ (437,934)	$ (450,453)	$ (460,185)	$ (466,994)	$ (5,094,823)
Revenue Requirement Subtotal	**$ 833,291**	**$ 1,233,122**	**$ 1,266,504**	**$ 1,480,442**	**$ 1,045,954**	**$ 1,341,965**	**$ 1,362,905**	**$ 1,327,037**	**$ 1,469,557**	**$ 1,593,107**	**$ 1,716,111**	**$ 1,701,728**	**$ 16,371,723**

Prior Year Carryover Balance	$ 4,751,786
Total Revenue Requirements	$ 21,123,510
Revenue Collections (Mar 24 - Feb 25)	$ 16,662,696
Current Year Carryover Balance	$ 4,460,814

Monthly Revenue Requirement Tracker Summary for 2025

	Jan-25 Forecast	Feb-25 Forecast	Mar-25 Forecast	Apr-25 Forecast	May-25 Forecast	Jun-25 Forecast	Jul-25 Forecast	Aug-25 Forecast	Sep-25 Forecast	Oct-25 Forecast	Nov-25 Forecast	Dec-25 Forecast	2025 Annual
Operations & Maintenance Expenses													
TIMP	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 44,075	$ 528,899
DIMP	127,361	127,361	127,361	127,361	127,361	127,361	127,361	127,361	127,361	127,361	127,361	127,361	1,528,333
Total Operations & Maintenance Expenses	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 171,436	$ 2,057,232
Capital-Related Revenue Requirements													
TIMP	$ 278,730	$ 282,756	$ 275,223	$ 251,856	$ 222,015	$ 221,812	$ 248,687	$ 242,882	$ 263,237	$ 296,173	$ 369,735	$ 424,560	$ 3,377,664
DIMP	1,200,890	1,206,615	1,200,940	1,185,165	1,172,583	1,175,901	1,210,726	1,237,556	1,286,362	1,316,630	1,376,088	1,433,597	15,003,051
Mandated Relocates	719,875	745,788	738,443	736,377	730,979	753,599	789,572	809,433	824,917	841,192	851,174	876,218	9,417,567
Total Capital-Related Revenue Requirements	$ 2,199,495	$ 2,235,158	$ 2,214,607	$ 2,173,398	$ 2,125,576	$ 2,151,312	$ 2,248,985	$ 2,289,870	$ 2,374,516	$ 2,453,994	$ 2,596,997	$ 2,734,374	$ 27,798,283
Regulatory Treatment	$ (1,015,988)	$ (475,000)	$ (477,438)	$ (489,009)	$ (515,925)	$ (546,211)	$ (567,270)	$ (583,349)	$ (598,355)	$ (610,519)	$ (619,895)	$ (626,347)	$ (7,125,307)
Revenue Requirement Subtotal	**$ 1,354,943**	**$ 1,931,594**	**$ 1,908,605**	**$ 1,855,825**	**$ 1,781,086**	**$ 1,776,537**	**$ 1,853,151**	**$ 1,877,957**	**$ 1,947,597**	**$ 2,014,911**	**$ 2,148,538**	**$ 2,279,463**	**$ 22,730,208**
												Prior Year Carryover Balance	$ 4,460,814
												Total Revenue Requirements	**$ 27,191,021**

Revenue Requirements Category Descriptions

Attachments G and H to this Petition respectively provide the TIMP and DIMP annual revenue requirements for 2025. The rate base categories in the proposed revenue requirements analysis and rationale for including or excluding costs in each category are explained below.

Plus Plant in Service: This is an addition to rate base. This category reflects the original cost of gas plant that has been put into service. In the specific case of the annual 2025 plant in service for gas utility infrastructure projects (GUIC), the $45.0 million for TIMP (Attachment G) and $229.8 million for DIMP and Mandated Relocations (Attachment H) reflect the dollar-value portion of the project in service as of December 31, 2025, which results in an increase to rate base. Standard ratemaking methodology calls for the inclusion of this item in the determination of rate base.

Less Book Depreciation Reserve: This is a reduction to rate base. It reflects the accumulated recovery of the amount invested in plant in service. In the specific case of the 2025 book depreciation reserve for GUIC projects, the $-0.1 million for TIMP (Attachment G) and $3.8 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of the plant in service that has been recovered as of December 31, 2025, which results in an increase to rate base. Standard ratemaking methodology calls for the exclusion of this credit balance in an asset account (contra-asset) from plant in service in the determination of rate base.

Less Accum Deferred Taxes: This is a reduction to rate base. It reflects the tax timing differences between book and tax depreciation lives and other non-plant book/tax timing differences, multiplied by the tax rate. Over the life of an asset, the Accumulated Deferred Tax is zero. In the specific case of the 2025 accumulated deferred taxes for GUIC projects, the $3.7 million for TIMP (Attachment G) and $9.3 million for DIMP and Mandated Relocations (Attachment H) reflect the accumulation of tax timing differences between book and tax depreciation through December 31, 2025, which results in a decrease to rate base. Standard ratemaking methodology calls for the exclusion of this timing-related asset in the determination of rate base.

Described below are the categories used to calculate the return in the proposed revenue requirements analysis, and the rationale for including costs in each category. Note that for both items below, standard ratemaking methodology calls for the inclusion of these items in the calculation of revenue requirements.

> **Plus Debt Return:** This category reflects the return the Company is allowed in order to recover its weighted cost of debt for financing its capital investments. In the specific case of the annual 2025 debt return for GUIC projects, the $0.5 million for TIMP (Attachment G) and $3.8 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of debt return the Company is allowed for January 2025 - December 2025 based on the cost of debt and ratios in the Company's recently settled natural gas rate case, Docket No. G002/GR-21-678.

> **Plus Equity Return:** This category reflects the return the Company is allowed in order to recover its weighted cost of equity for financing its capital investments. In the specific case of the annual 2025 equity return for GUIC projects, the $1.4 million for TIMP (Attachment G) and $9.7 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of return on equity the Company is allowed for January 2025 - December 2025 based on the equity ratio in the Company's recently settled natural gas rate case, Docket No. G002/GR-21-678.

The types of income statement categories, description and rationale for including costs in each category in the Company's proposed revenue requirements analysis are described below. For all four items, standard ratemaking methodology calls for the inclusion of these items in the calculation of revenue requirements.

> **Plus Property Taxes:** This category reflects the estimated property taxes billed from local taxing authorities that the Company must pay based on the original cost of the Company's assets. Property taxes accrued are based on the original cost at December 31 from the prior year, and then paid the following year. In the specific case of the estimated annual 2025 property tax amount for GUIC projects, the $0.4 million for TIMP (Attachment G) and $2.4 million for DIMP and Mandated Relocations (Attachment H) reflect property tax rates based on ending plant in service as of December 31, 2023 payable in 2025.

Plus Book Depreciation: This category reflects the monthly/annual depreciation expense that is accumulated in the book depreciation reserve defined in part a) subsection ii). In the specific case of the annual 2025 book depreciation for GUIC projects, the $0.5 million for TIMP (Attachment G) and $4.7 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of plant in service that is being recovered through depreciation expense from January 2025-December 2025 and results in an increase to revenue requirements.

Plus Deferred Taxes: This category reflects the monthly/annual deferred tax expense that is accumulated in the accumulated deferred reserve defined in part a) subsection iii). In the specific case of the annual 2025 deferred taxes for GUIC projects, the $1.1 million for TIMP (Attachment G) and $3.2 million for DIMP and Mandated Relocations (Attachment H) reflect the January 1, 2025 - December 31, 2025 tax timing difference when book expense differs from tax expense and results in an increase to revenue requirements.

Plus Gross Up for Income Taxes: This category reflects the current income taxes the Company is anticipated to pay based on its taxable income. In the specific case of the annual 2025 current taxes for GUIC projects, the $-0.5 million for TIMP (Attachment G) and $0.7 million for DIMP and Mandated Relocations (Attachment H) reflect the amount of current income taxes the Company is anticipating paying as a result of the taxable income being generated by GUIC projects.

Monthly Collection Pattern
GUIC Rate Factor Calculations

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25
Revenue Requirement Subtotal	$ 833,291	$ 1,233,122	$ 1,266,504	$ 1,480,442	$ 1,045,954	$ 1,341,965	$ 1,362,905	$ 1,327,037	$ 1,469,557	$ 1,593,107	$ 1,716,111	$ 1,701,728	$ 1,354,943	$ 1,931,594
Revenue Collections	$ 4,919,428	$ 3,707,137	$ 2,642,199	$ 1,700,053	$ 853,320	$ 596,297	$ 687,668	$ 718,755	$ 716,968	$ 1,366,502	$ 2,682,912	$ 4,106,354	$ 4,318,151	$ 4,017,845
Carryover Rollforward:														
Carryover Beginning Balance	$ 11,599,517	$ 6,680,089	$ 2,972,952	$ 27,783,114	$ 24,816,557	$ 23,963,237	$ 23,366,940	$ 22,679,272	$ 21,960,517	$ 21,243,549	$ 19,877,047	$ 17,194,135	$ 13,087,782	$ 8,769,631
Activity (Under/(Over) Collection)	(4,086,137)	(2,474,015)	(1,375,695)	(219,611)	192,634	745,669	675,236	608,282	752,589	226,605	(966,801)	(2,404,626)	(2,963,208)	(2,086,250)
Deferral Impact	(833,291)	(1,233,122)	26,185,856	(2,746,946)	(1,045,954)	(1,341,965)	(1,362,905)	(1,327,037)	(1,469,557)	(1,593,107)	(1,716,111)	(1,701,728)	(1,354,943)	(1,931,594)
Carryover Ending Balance	$ 6,680,089	$ 2,972,952	$ 27,783,114	$ 24,816,557	$ 23,963,237	$ 23,366,940	$ 22,679,272	$ 21,960,517	$ 21,243,549	$ 19,877,047	$ 17,194,135	$ 13,087,782	$ 8,769,631	$ 4,751,786

2023 Annual Revenue Requirements (Jan 2023-Dec 2023)	$ 26,185,856
Carryover Balance at beginning of collection period	$ 2,972,952
Total 2023 Revenue Requirement	$ 29,158,808
Revenue Collections from Mar 2024-Feb 2025	$ 24,407,022
Carryover Balance at End of collection period	$ 4,751,786

Rate by Class:	Actual	Actual	Actual	Actual	Actual	Actual	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
Estimated Revenue Collections	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25
Residential	$ 3,446,772	$ 2,521,166	$ 1,662,533	$ 1,016,784	$ 394,827	$ 285,752	$ 257,466	$ 268,254	$ 353,758	$ 840,002	$ 1,720,398	$ 2,752,710	$ 2,929,928	$ 2,657,636
Commercial Firm	1,030,451	862,276	651,907	413,313	185,625	139,952	116,956	125,298	156,459	338,471	646,630	1,012,864	1,036,374	1,042,763
Commercial Demand Billed	18,497	14,450	14,434	10,574	7,682	7,276	253,443	261,011	149,010	123,240	188,888	215,075	231,825	216,644
Interruptible	171,222	133,510	90,181	79,122	45,061	47,693	59,804	64,192	57,742	64,789	126,997	125,705	120,023	100,802
Transport	252,485	175,736	223,144	180,260	220,125	115,624								
	$ 4,919,428	$ 3,707,137	$ 2,642,199	$ 1,700,053	$ 853,320	$ 596,297	$ 687,668	$ 718,755	$ 716,968	$ 1,366,502	$ 2,682,912	$ 4,106,354	$ 4,318,151	$ 4,017,845

	Jul 23 Act WN	*Aug 23 Act WN*	*Sep 23 Act WN*	*Oct 23 Act WN*	*Nov 23 Act WN*	*Dec 23 Act WN*	*Jan 24 Act WN*	*Feb 24 Act WN*
Sales by Customer Group	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25
Residential	$ 634,965	$ 661,571	$ 872,441	$ 2,071,623	$ 4,242,867	$ 6,788,769	$ 7,225,827	$ 6,554,296
Commercial Firm	466,721	500,011	624,361	1,350,698	2,580,429	4,041,915	4,135,736	4,161,233
Demand	4,979,225	5,127,925	2,927,503	2,421,211	3,710,957	4,225,447	4,554,521	4,256,260
Interruptible	631,981	678,346	610,183	684,655	1,342,038	1,328,385	1,268,341	1,065,220
Total Sales	$ 6,712,893	$ 6,967,853	$ 5,034,488	$ 6,528,187	$ 11,876,291	$ 16,384,516	$ 17,184,425	$ 16,037,008

Allocated Cost								
Residential	$0.4054800	$0.4054800	$0.4054800	$0.4054800	$0.4054800	$0.4054800	$0.4054800	$0.4054800
Commercial Firm	$0.2505900	$0.2505900	$0.2505900	$0.2505900	$0.2505900	$0.2505900	$0.2505900	$0.2505900
Demand	$0.0509000	$0.0509000	$0.0509000	$0.0509000	$0.0509000	$0.0509000	$0.0509000	$0.0509000
Interruptible	$0.0946300	$0.0946300	$0.0946300	$0.0946300	$0.0946300	$0.0946300	$0.0946300	$0.0946300

Monthly Collection Pattern
GUIC Rate Factor Calculations

	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26
Revenue Requirement Subtotal	$ 1,908,605	$ 1,855,825	$ 1,781,086	$ 1,776,537	$ 1,853,151	$ 1,877,957	$ 1,947,597	$ 2,014,911	$ 2,148,538	$ 2,279,463	$ 1,665,507	$ 2,358,270
Revenue Collections	$ 1,971,049	$ 1,210,281	$ 654,389	$ 416,848	$ 418,617	$ 438,383	$ 460,662	$ 910,581	$ 1,799,697	$ 2,767,782	$ 2,909,474	$ 2,704,933
Carryover Rollforward:												
Carryover Beginning Balance	$ 4,751,786	$ 21,061,065	$ 17,942,179	$ 17,287,791	$ 16,870,942	$ 16,452,325	$ 16,013,943	$ 15,553,280	$ 14,642,700	$ 12,843,002	$ 10,075,221	$ 7,165,746
Activity (Under/(Over) Collection)	(62,444)	645,544	1,126,698	1,359,689	1,434,534	1,439,574	1,486,935	1,104,330	348,841	(488,319)	(1,243,967)	(346,663)
Deferral Impact	16,371,723	(3,764,429)	(1,781,086)	(1,776,537)	(1,853,151)	(1,877,957)	(1,947,597)	(2,014,911)	(2,148,538)	(2,279,463)	(1,665,507)	(2,358,270)
Carryover Ending Balance	$ 21,061,065	$ 17,942,179	$ 17,287,791	$ 16,870,942	$ 16,452,325	$ 16,013,943	$ 15,553,280	$ 14,642,700	$ 12,843,002	$ 10,075,221	$ 7,165,746	$ 4,460,814

2024 Annual Revenue Requirements (Jan 2024-Dec 2024)	$ 16,371,723
Carryover Balance at beginning of collection period	$ 4,751,786
Total 2024 Revenue Requirement	$ 21,123,510
Revenue Collections from Mar 2025-Feb 2026	$ 16,662,696
Carryover Balance at End of collection period	$ 4,460,814

Rate by Class:	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
Estimated Revenue Collections	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**
Residential	$ 1,291,535	$ 782,747	$ 373,624	$ 204,600	$ 177,508	$ 184,945	$ 243,895	$ 579,132	$ 1,186,114	$ 1,897,833	$ 2,020,014	$ 1,832,285
Commercial Firm	482,427	305,579	161,900	96,243	78,223	83,802	104,644	226,378	432,482	677,429	693,154	697,427
Commercial Demand Billed	130,307	63,975	85,211	81,857	119,568	123,139	70,299	58,141	89,112	101,467	109,369	102,207
Interruptible	66,780	57,981	33,653	34,148	43,319	46,497	41,824	46,929	91,989	91,053	86,937	73,015
Transport												
	$ 1,971,049	$ 1,210,281	$ 654,389	$ 416,848	$ 418,617	$ 438,383	$ 460,662	$ 910,581	$ 1,799,697	$ 2,767,782	$ 2,909,474	$ 2,704,933

	Mar 24 Act WN	*Apr 24 Act WN*	*May 24 Act WN*	*Jun 24 Act WN*	*Jul 23 Act WN*	*Aug 23 Act WN*	*Sep 23 Act WN*	*Oct 23 Act WN*	*Nov 23 Act WN*	*Dec 23 Act WN*	*Jan 24 Act WN*	*Feb 24 Act WN*
Sales by Customer Group	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**
Residential	$ 4,619,971	$ 2,799,976	$ 1,336,498	$ 731,877	$ 634,965	$ 661,571	$ 872,441	$ 2,071,623	$ 4,242,867	$ 6,788,769	$ 7,225,827	$ 6,554,296
Commercial Firm	2,878,428	1,823,255	965,984	574,237	466,721	500,011	624,361	1,350,698	2,580,429	4,041,915	4,135,736	4,161,233
Demand	5,426,435	2,664,131	3,548,485	3,408,828	4,979,225	5,127,925	2,927,503	2,421,211	3,710,957	4,225,447	4,554,521	4,256,260
Interruptible	974,261	845,886	490,975	498,197	631,981	678,346	610,183	684,655	1,342,038	1,328,385	1,268,341	1,065,220
Total Sales	$ 13,899,095	$ 8,133,249	$ 6,341,943	$ 5,213,140	$ 6,712,893	$ 6,967,853	$ 5,034,488	$ 6,528,187	$ 11,876,291	$ 16,384,516	$ 17,184,425	$ 16,037,008

Allocated Cost												
Residential	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548	$0.2795548
Commercial Firm	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010	$0.1676010
Demand	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133	$0.0240133
Interruptible	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441	$0.0685441

Monthly Collection Pattern
GUIC Rate Factor Calculations

	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27
Revenue Requirement Subtotal	$ 2,338,821	$ 2,301,164	$ 2,246,861	$ 2,243,072	$ 2,302,915	$ 2,336,863	$ 2,401,136	$ 2,441,653	$ 2,518,903	$ 2,632,236	$ 1,926,914	$ 2,695,575
Revenue Collections	$ 3,211,036	$ 1,977,541	$ 1,068,403	$ 683,697	$ 688,204	$ 721,128	$ 757,450	$ 1,488,561	$ 2,942,507	$ 4,510,625	$ 4,738,605	$ 4,403,263
Carryover Rollforward:												
Carryover Beginning Balance	$ 4,460,814	$ 26,318,806	$ 22,002,444	$ 20,934,041	$ 20,250,344	$ 19,562,140	$ 18,841,012	$ 18,083,562	$ 16,595,001	$ 13,652,493	$ 9,141,868	$ 4,403,263
Activity (Under/(Over) Collection)	(872,215)	323,623	1,178,458	1,559,374	1,614,711	1,615,735	1,643,686	953,091	(423,604)	(1,878,389)	(2,811,691)	(1,707,688)
Deferral Impact	22,730,208	(4,639,985)	(2,246,861)	(2,243,072)	(2,302,915)	(2,336,863)	(2,401,136)	(2,441,653)	(2,518,903)	(2,632,236)	(1,926,914)	(2,695,575)
Carryover Ending Balance	$ 26,318,806	$ 22,002,444	$ 20,934,041	$ 20,250,344	$ 19,562,140	$ 18,841,012	$ 18,083,562	$ 16,595,001	$ 13,652,493	$ 9,141,868	$ 4,403,263	$ -

2025 Annual Revenue Requirements (Jan 2025-Dec 2025)	$ 22,730,208
Carryover Balance at beginning of collection period	$ 4,460,814
Total 2025 Revenue Requirement	$ 27,191,021
Revenue Collections from Mar 2026-Feb 2027	$ 27,191,021
Carryover Balance at End of collection period	$ -

Rate by Class:	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*
Estimated Revenue Collections	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**
Residential	$ 2,091,327	$ 1,267,468	$ 604,994	$ 331,300	$ 287,430	$ 299,474	$ 394,929	$ 937,764	$ 1,920,623	$ 3,073,079	$ 3,270,922	$ 2,966,940
Commercial Firm	783,560	496,323	262,958	156,318	127,050	136,112	169,962	367,684	702,439	1,100,282	1,125,822	1,132,763
Commercial Demand Billed	207,025	101,640	135,379	130,051	189,964	195,637	111,688	92,372	141,578	161,206	173,761	162,382
Interruptible	129,124	112,110	65,072	66,029	83,760	89,905	80,871	90,741	177,867	176,058	168,100	141,179
Transport												
	$ 3,211,036	$ 1,977,541	$ 1,068,403	$ 683,697	$ 688,204	$ 721,128	$ 757,450	$ 1,488,561	$ 2,942,507	$ 4,510,625	$ 4,738,605	$ 4,403,263

	Mar 24 Act WN	*Apr 24 Act WN*	*May 24 Act WN*	*Jun 24 Act WN*	*Jul 23 Act WN*	*Aug 23 Act WN*	*Sep 23 Act WN*	*Oct 23 Act WN*	*Nov 23 Act WN*	*Dec 23 Act WN*	*Jan 24 Act WN*	*Feb 24 Act WN*
Sales by Customer Group	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**
Residential	$ 4,619,971	$ 2,799,976	$ 1,336,498	$ 731,877	$ 634,965	$ 661,571	$ 872,441	$ 2,071,623	$ 4,242,867	$ 6,788,769	$ 7,225,827	$ 6,554,296
Commercial Firm	2,878,428	1,823,255	965,984	574,237	466,721	500,011	624,361	1,350,698	2,580,429	4,041,915	4,135,736	4,161,233
Demand	5,426,435	2,664,131	3,548,485	3,408,828	4,979,225	5,127,925	2,927,503	2,421,211	3,710,957	4,225,447	4,554,521	4,256,260
Interruptible	974,261	845,886	490,975	498,197	631,981	678,346	610,183	684,655	1,342,038	1,328,385	1,268,341	1,065,220
Total Sales	$ 13,899,095	$ 8,133,249	$ 6,341,943	$ 5,213,140	$ 6,712,893	$ 6,967,853	$ 5,034,488	$ 6,528,187	$ 11,876,291	$ 16,384,516	$ 17,184,425	$ 16,037,008

Allocated Cost												
Residential	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710	$0.4526710
Commercial Firm	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181	$0.2722181
Demand	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513	$0.0381513
Interruptible	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353	$0.1325353

Northern States Power Company

Carryover Rollforward
GUIC Over/Under Collection

Carryover Rollforward:	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**
Carryover Beginning Balance	$ 11,599,517	$ 6,680,089	$ 2,972,952	$ 27,783,114	$ 24,816,557	$ 23,963,237	$ 23,366,940	$ 22,679,272	$ 21,960,517	$ 21,243,549	$ 19,877,047	$ 17,194,135	$ 13,087,782	$ 8,769,631
Revenue Requirement	$ 833,291	$ 1,233,122	$ 1,266,504	$ 1,480,442	$ 1,045,954	$ 1,341,965	$ 1,362,905	$ 1,327,037	$ 1,469,557	$ 1,593,107	$ 1,716,111	$ 1,701,728	$ 1,354,943	$ 1,931,594
Deferral Impact	$ (833,291)	$ (1,233,122)	$ 26,185,856	$ (2,746,946)	$ (1,045,954)	$ (1,341,965)	$ (1,362,905)	$ (1,327,037)	$ (1,469,557)	$ (1,593,107)	$ (1,716,111)	$ (1,701,728)	$ (1,354,943)	$ (1,931,594)
Revenue Collections							Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential							$ 257,466	$ 268,254	$ 353,758	$ 840,002	$ 1,720,398	$ 2,752,710	$ 2,929,928	$ 2,657,636
Commercial Firm							116,956	125,298	156,459	338,471	646,630	1,012,864	1,036,374	1,042,763
Commercial Demand Billed							253,443	261,011	149,010	123,240	188,888	215,075	231,825	216,644
Interruptible							59,804	64,192	57,742	64,789	126,997	125,705	120,023	100,802
Transport							-	-	-	-	-	-	-	-
Total Revenue Collections	$ 4,919,428	$ 3,707,137	$ 2,642,199	$ 1,700,053	$ 853,320	$ 596,297	$ 687,668	$ 718,755	$ 716,968	$ 1,366,502	$ 2,682,912	$ 4,106,354	$ 4,318,151	$ 4,017,845
Activity (Under/(Over) Collection)	**$ 6,680,089**	**$ 2,972,952**	**$ 27,783,114**	**$ 24,816,557**	**$ 23,963,237**	**$ 23,366,940**	**$ 22,679,272**	**$ 21,960,517**	**$ 21,243,549**	**$ 19,877,047**	**$ 17,194,135**	**$ 13,087,782**	**$ 8,769,631**	**$ 4,751,786**

Northern States Power Company

Docket No. G002/M-24-____
Gas Utility Infrastructure Cost Rider - 2025 Factors
Attachment S - Page 2 of 3

Carryover Rollforward
GUIC Over/Under Collection

Carryover Rollforward:	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**
Carryover Beginning Balance	$ 4,751,786	$ 21,061,065	$ 17,942,179	$ 17,287,791	$ 16,870,942	$ 16,452,325	$ 16,013,943	$ 15,553,280	$ 14,642,700	$ 12,843,002	$ 10,075,221	$ 7,165,746	$ 4,460,814	$ 26,318,806
Revenue Requirement	$ 1,908,605	$ 1,855,825	$ 1,781,086	$ 1,776,537	$ 1,853,151	$ 1,877,957	$ 1,947,597	$ 2,014,911	$ 2,148,538	$ 2,279,463	$ 1,665,507	$ 2,358,270	$ 2,338,821	$ 2,301,164
Deferral Impact	$ 16,371,723	$ (3,764,429)	$ (1,781,086)	$ (1,776,537)	$ (1,853,151)	$ (1,877,957)	$ (1,947,597)	$ (2,014,911)	$ (2,148,538)	$ (2,279,463)	$ (1,665,507)	$ (2,358,270)	$ 22,730,208	$ (4,639,985)
Revenue Collections	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential	$ 1,291,535	$ 782,747	$ 373,624	$ 204,600	$ 177,508	$ 184,945	$ 243,895	$ 579,132	$ 1,186,114	$ 1,897,833	$ 2,020,014	$ 1,832,285	$ 2,091,327	$ 1,267,468
Commercial Firm	482,427	305,579	161,900	96,243	78,223	83,802	104,644	226,378	432,482	677,429	693,154	697,427	783,560	496,323
Commercial Demand Billed	130,307	63,975	85,211	81,857	119,568	123,139	70,299	58,141	89,112	101,467	109,369	102,207	207,025	101,640
Interruptible	66,780	57,981	33,653	34,148	43,319	46,497	41,824	46,929	91,989	91,053	86,937	73,015	129,124	112,110
Transport	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Revenue Collections	$ 1,971,049	$ 1,210,281	$ 654,389	$ 416,848	$ 418,617	$ 438,383	$ 460,662	$ 910,581	$ 1,799,697	$ 2,767,782	$ 2,909,474	$ 2,704,933	$ 3,211,036	$ 1,977,541
Activity (Under/(Over) Collection)	**$ 21,061,065**	**$ 17,942,179**	**$ 17,287,791**	**$ 16,870,942**	**$ 16,452,325**	**$ 16,013,943**	**$ 15,553,280**	**$ 14,642,700**	**$ 12,843,002**	**$ 10,075,221**	**$ 7,165,746**	**$ 4,460,814**	**$ 26,318,806**	**$ 22,002,444**

Carryover Rollforward
GUIC Over/Under Collection

Carryover Rollforward:	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**
Carryover Beginning Balance	$ 22,002,444	$ 20,934,041	$ 20,250,344	$ 19,562,140	$ 18,841,012	$ 18,083,562	$ 16,595,001	$ 13,652,493	$ 9,141,868	$ 4,403,263
Revenue Requirement	$ 2,246,861	$ 2,243,072	$ 2,302,915	$ 2,336,863	$ 2,401,136	$ 2,441,653	$ 2,518,903	$ 2,632,236	$ 1,926,914	$ 2,695,575
Deferral Impact	$ (2,246,861)	$ (2,243,072)	$ (2,302,915)	$ (2,336,863)	$ (2,401,136)	$ (2,441,653)	$ (2,518,903)	$ (2,632,236)	$ (1,926,914)	$ (2,695,575)
Revenue Collections	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Residential	$ 604,994	$ 331,300	$ 287,430	$ 299,474	$ 394,929	$ 937,764	$ 1,920,623	$ 3,073,079	$ 3,270,922	$ 2,966,940
Commercial Firm	262,958	156,318	127,050	136,112	169,962	367,684	702,439	1,100,282	1,125,822	1,132,763
Commercial Demand Billed	135,379	130,051	189,964	195,637	111,688	92,372	141,578	161,206	173,761	162,382
Interruptible	65,072	66,029	83,760	89,905	80,871	90,741	177,867	176,058	168,100	141,179
Transport	-	-	-	-	-	-	-	-	-	-
Total Revenue Collections	$ 1,068,403	$ 683,697	$ 688,204	$ 721,128	$ 757,450	$ 1,488,561	$ 2,942,507	$ 4,510,625	$ 4,738,605	$ 4,403,263
Activity (Under/(Over) Collection)	**$ 20,934,041**	**$ 20,250,344**	**$ 19,562,140**	**$ 18,841,012**	**$ 18,083,562**	**$ 16,595,001**	**$ 13,652,493**	**$ 9,141,868**	**$ 4,403,263**	**$ -**

Redline

APPLICABILITY
Applicable to bills for natural gas service provided under the Company's retail rate schedules.

RIDER
The Gas Utility Infrastructure Cost (GUIC) Rider is designed to collect the costs of assessments, modifications, and replacement of natural gas facilities as required to comply with state and federal pipeline safety programs. There shall be included on each customer's monthly bill a GUIC Rider charge, which shall be calculated by multiplying the monthly applicable billing therms for natural gas service by the GUIC Rider Factor for the appropriate customer group.

DETERMINATION OF GUIC RIDER FACTORS
A separate GUIC Rider Factor shall be calculated for the following four customer groups: (1) Residential, (2) Commercial Firm, (3) Commercial Demand Billed, and (4) Interruptible. The GUIC Rider Factor for each customer group shall be the value obtained by multiplying the balance of the GUIC Rider Tracker Account by each customer group's allocation factor, divided by the forecasted sales for the customer group in the recovery period.

The GUIC Rider Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). On or before November 1, the Company will file a GUIC Rider Annual Report with request to change the GUIC Rider Factor.

The current GUIC Rider Factor for each customer group is:

Residential	$~~0.027955~~0.045267 per therm	R
Commercial Firm	$~~0.016760~~0.027222 per therm	R
Commercial Demand Billed	$~~0.002401~~0.003815 per therm	R
Interruptible	$~~0.006854~~0.013254 per therm	R

Recoverable GUIC Rider Expenses
Recoverable GUIC Rider Expenses shall be the annual revenue requirements for costs associated with natural gas infrastructure projects eligible for recovery under Minnesota Statute Sections 216B.1635 or 216B.16, subd. 11 that are determined by the Commission to be eligible for recovery under this GUIC Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the GUIC Rider Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the GUIC Rider Factor shall be credited to the GUIC Rider Tracker Account. The GUIC Rider Tracker Account includes adjustments for forecasted revenue requirements compared to actual revenue requirements and for actual revenue requirements compared to actual revenue recovery.

(Continued on Sheet No. 5-65)

Clean

APPLICABILITY
Applicable to bills for natural gas service provided under the Company's retail rate schedules.

RIDER
The Gas Utility Infrastructure Cost (GUIC) Rider is designed to collect the costs of assessments, modifications, and replacement of natural gas facilities as required to comply with state and federal pipeline safety programs. There shall be included on each customer's monthly bill a GUIC Rider charge, which shall be calculated by multiplying the monthly applicable billing therms for natural gas service by the GUIC Rider Factor for the appropriate customer group.

DETERMINATION OF GUIC RIDER FACTORS
A separate GUIC Rider Factor shall be calculated for the following four customer groups: (1) Residential, (2) Commercial Firm, (3) Commercial Demand Billed, and (4) Interruptible. The GUIC Rider Factor for each customer group shall be the value obtained by multiplying the balance of the GUIC Rider Tracker Account by each customer group's allocation factor, divided by the forecasted sales for the customer group in the recovery period.

The GUIC Rider Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). On or before November 1, the Company will file a GUIC Rider Annual Report with request to change the GUIC Rider Factor.

The current GUIC Rider Factor for each customer group is:

Residential	$0.045267 per therm	R
Commercial Firm	$0.027222 per therm	R
Commercial Demand Billed	$0.003815 per therm	R
Interruptible	$0.013254 per therm	R

<u>Recoverable GUIC Rider Expenses</u>
Recoverable GUIC Rider Expenses shall be the annual revenue requirements for costs associated with natural gas infrastructure projects eligible for recovery under Minnesota Statute Sections 216B.1635 or 216B.16, subd. 11 that are determined by the Commission to be eligible for recovery under this GUIC Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the GUIC Rider Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the GUIC Rider Factor shall be credited to the GUIC Rider Tracker Account. The GUIC Rider Tracker Account includes adjustments for forecasted revenue requirements compared to actual revenue requirements and for actual revenue requirements compared to actual revenue recovery.

(Continued on Sheet No. 5-65)

Xcel Energy	**Gas Utility Infrastructure Cost (GUIC) Rider Performance Metrics**

Introduction

This attachment discusses our proposal for metrics to measure the appropriateness of GUIC expenditures and is provided pursuant to Order Point 2 of the Minnesota Public Utilities Commission's August 18, 2016, Order[1] in Docket No. G002/M-15-808. That Order required that:

> *The Company develop metrics to measure the appropriateness of GUIC expenditures, to be included in future GUIC filings, and provide stakeholders the opportunity for meaningful involvement.*

The Commission also instructed that:

> *Each metric should include reconciliation to the pertinent TIMP/DIMP rules, and/or if not tied to TIMP/DIMP requirement, the Company must identify what goal, benefit, and/or requirement it addresses.*

The Company made our initial metrics proposal, in compliance with that Order, as a supplemental filing in our 2017 GUIC Rider filing.[2] Before submitting the original proposal, the Company engaged with stakeholders to gather input on the proposed metrics. The same proposed metrics were included in our 2018 GUIC Rider request.[3]

In its February 8, 2018, Order,[4] the Commission declined to adopt the proposed metrics and ordered us to continue to discuss metrics with other parties. The Company continued the discussion with stakeholders on metrics prior to submitting the metrics proposal below, through meetings with stakeholders from the Commission Staff, the Department of Commerce (Department), Minnesota Office of Pipeline Safety (MNOPS), and Office of the Attorney General (OAG), on September 26, 2018, and again on August 27, 2019.

---

[1] ORDER REQUIRING UPDATED REPORT, APPROVING RIDER RECOVERY, AND REQUIRING METRICS TO EVALUATE GUIC EXPENDITURES, Docket No. G002/M-15-808 (August 18, 2016).
[2] *See* Supplement and Compliance Metrics Proposal, Docket No. G002/M-16-891 (January 13, 2017).
[3] *See* Petition, Compliance Filing, and Annual Report, Page 42, Docket No. G002/M-17-787 (November 1, 2017).
[4] *See* ORDER APPROVING RIDER WITH MODIFICATIONS, Docket No. G002/M-16-891 (February 8, 2018).

The Commission also declined to approve the performance metrics we proposed in our 2019 GUIC Rider filing and required continued discussions to gain consensus.[5] In late 2019, the Company asked stakeholders to provide informal comments on the current proposal. Both the Department and OAG provided information laying out their positions on metrics for the GUIC. Based on the comments provided by the parties, the differences between the Company and parties appeared to be small.

On September 16, 2020, the Department filed Comments in our 2020 GUIC Rider docket and discussed their current position on metrics. They stated:

> *Given Xcel's ongoing efforts to address the Department's concerns, the Department is reassured that the Company will continue to refine performance metrics reporting as it is able to. Therefore, the Department is no longer opposed to the metrics currently proposed by the Company.*[6]

Given the Department's statement, we believe we have reached a consensus on a baseline set of GUIC Rider metrics that we can start with. We take to heart their understanding that we will continue to refine our metrics over time in order to provide a level of information that will make the review of our GUIC Rider filings easier.

In its May 3, 2021, Order[7], the Commission stated it would not establish any specific performance metrics or related requirements in the Order, and that the Commission anticipates that it will have the opportunity to evaluate a proposal for specific, concrete performance metrics in Xcel's 2021 GUIC Petition.

On June 23, 2021, the Department filed Comments in our 2021 GUIC Rider docket and discussed their current position on metrics. They stated:

> *The Department also reviewed the performance metric outcomes of Xcel's prior years' project work, included in Attachment U, and concludes that Xcel's reported performance results appear reasonable.*[8]

---

[5] *See* ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS, Docket No. G002/M-18-692 (January 9, 2020), Order Point 18.
[6] *See* Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket No. G002/M-19-664 (September 16, 2020), Pages 15-16.
[7] *See* ORDER AUTHORIZING RIDER RECOVERY WITH MODIFICATIONS, Docket No. G002/M-19-664 (May 3,2021), Order Point 6.
[8] *See* Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket No. G002/M-20-799 (June 23, 2021), Pages 18-19.

Within our 2022 GUIC Rider docket, we proposed new cost and effectiveness performance metrics for the new programs that started in 2021 (casing renewal and mandated relocation programs), and additional metrics for the new portion of our distribution valve replacement program. These proposed metrics are relevant measurements of performance. Having full experience data for 2021 the Company is now providing these metric results. We look forward to continuing our work with the Department to refine these metrics over time.

On July 11, 2022, the Department filed Comments in our 2022 GUIC Rider docket and the only reference to performance metrics was regarding using them as gas asset planning tools in the future of gas docket. They stated:

> *The Commission may also wish to consider discussing other gas asset planning tools used in the GUIC proceedings – such as risk assessments and performance metrics – in the future of gas docket.*[9]

Table 1 below shows the TIMP and DIMP performance metrics we believe would be most useful at this time.

Table 1
Recommended Performance Metrics - TIMP

Program	Project	Cost Performance Metric	Effectiveness Performance Metric
TIMP	Transmission Pipeline Integrity Assessments	Estimated versus actual costs per project	Anomalies repaired by type
	ASVs and RCVs	Estimated versus actual costs per project	Reduction in response time per project
	Programmatic Replacement and MAOP Remediation	Estimated versus actual costs per project	Percentage of high/medium risk projects system-wide
	Casing Renewal	Estimated versus actual costs per project	Percentage of Planned Casings Remediated

[9] *See* Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket No. G002/M-21-765 (July 11, 2022), Page 6.

Table 1 (continued)
Recommended Performance Metrics - DIMP

Program	Project	Cost Performance Metric	Effectiveness Performance Metric
DIMP	Poor Performing Main Replacement	Poor performing main replacement unit cost (per foot)	Leak rate by vintage
	Poor Performing Service Replacement	Poor performing service replacement unit cost (per foot)	Leak rate by vintage
	Distribution Pipeline Integrity Assessment	Estimated versus actual costs per project	Anomalies repaired by type
	Distribution Valve Replacement	Estimated versus actual costs per project	Percentage of Inoperable Valves Replaced
			Reduction in potential customer outage
	Casing Renewal	Estimated versus actual costs per project	Percentage of Planned Casings Remediated
Mandated Relocations		Estimated versus actual costs per project	Number of Planned vs. Actual Relocations

A. TIMP Metrics

The goal of projects under the Company's TIMP is to detect and repair pipe anomalies and to mitigate the consequence of a failure. The detection and repair of anomalies is achieved primarily through Pipeline Assessments, Replacement, and MAOP remediation. The potential consequences of a pipe failure are mitigated primarily by the installation of Remote-Control Valves (RCVs).

1) Transmission Pipeline Integrity Assessments

2023 Estimated vs. Actual Project Costs
($ Millions)

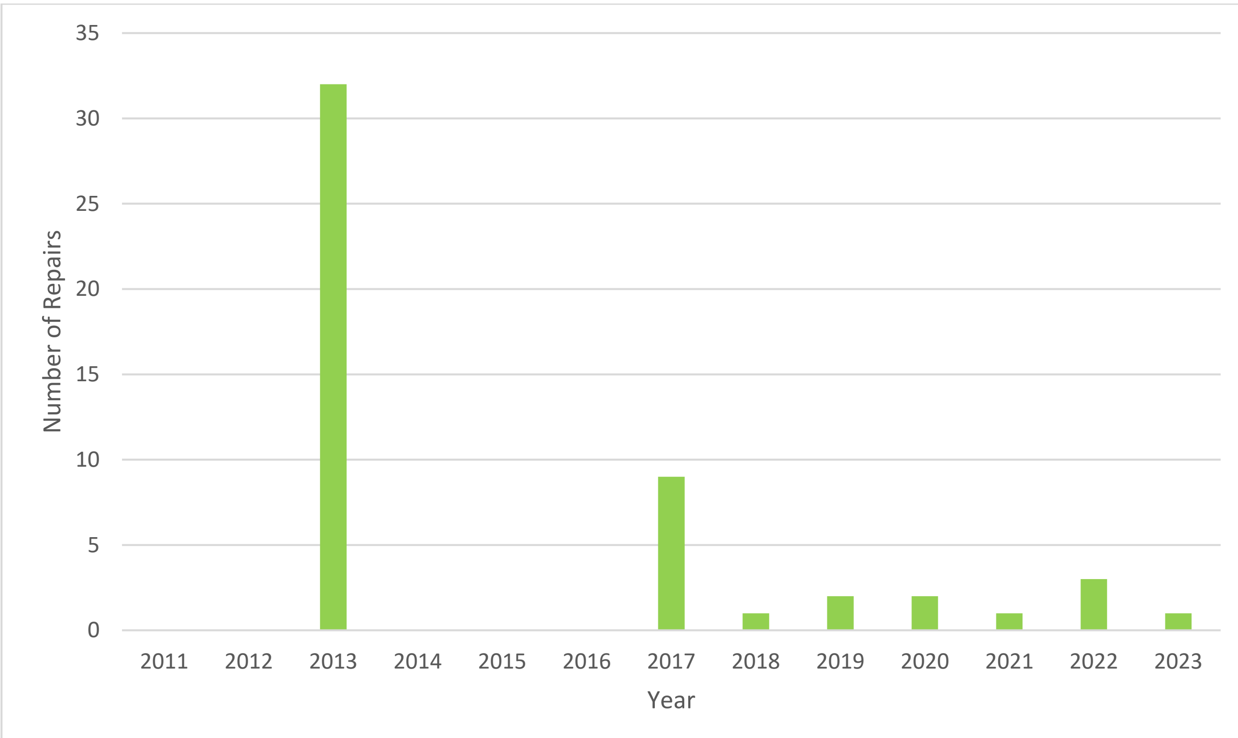
	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.26	$0.43	$0.18	68.99%	$0.63	$0.46	($0.16)	-26.29%

Variance Explanation

Capital: The increase in capital expenditures is due to a determination by Capital Asset Accounting that sleeve repairs can be classified as capital repairs, and greater than expected construction costs and timeline on the Wescott lines.

O&M: The variance is due to a determination by Capital Asset Accounting that sleeve repairs can be classified as capital repairs; historically, these repairs were considered O&M.

Figure 1
NSPM Gas Transmission Number of Anomalies Repaired



Anomaly repairs are expected to vary from year to year as different pipelines are inspected or assessed each year. However, as assessments continue and anomalies are repaired, the Company anticipates the number of repairs to ultimately reduce.

Table 2 below shows the anomalies repaired, by type of anomaly repaired.

Table 2
TIMP Repairs by Anomaly Type

Anomaly Type	Number of Repairs
External Corrosion	16
Internal Corrosion	0
Stress Corrosion Cracking	0
Manufacturing	3
Construction	4
Equipment	0
Third-Party Damage	28
Incorrect Operations	0
Weather and Outside Force	0
Total	51

2) ASVs and RCVs

2023 Estimated vs. Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$0.00	$0.00	$0.0	0.00%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: None.

O&M: None.

Figure 2
Reduction in Response Time per Project

Line #	Line Name	RCV Location	Nearest Service Center	Response Time (Min)
N/A	N/A for 2023	N/A	N/A	N/A

As mentioned previously, the potential consequences of a pipe failure are mitigated primarily by the installation of Remote-Control Valves (RCVs). Installation of RCVs reduces the response time needed to shut off the flow of gas in the event of an incident.

3) Programmatic Replacement / MAOP Remediation

2023 Estimated vs. Actual Project Costs
($ Millions)

	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$8.64	$6.16	($2.48)	-28.68%	$0.05	$0.00	($0.05)	-100.00%

Variance Explanation

Capital: The variance is due to delays in planned engineering and design on the East County Line projects. These projects will be constructed in 2023.

O&M: None.

Figure 3
Percentage of High-Risk Projects System-Wide

Risk Category	Project Risk Scores Range	Number of pipelines identified as of December 31, 2021	Percentage
High	Risk Score ≥ 5	9	22.5%
Low	Risk < 5	10	25%
No Risk	Risk Score = 0	0	0%
Under Evaluation	TBD	21	52.5%
Total	All	40	

4) Casing Renewal

2023 Estimated vs. Actual Project Costs
($ Millions)

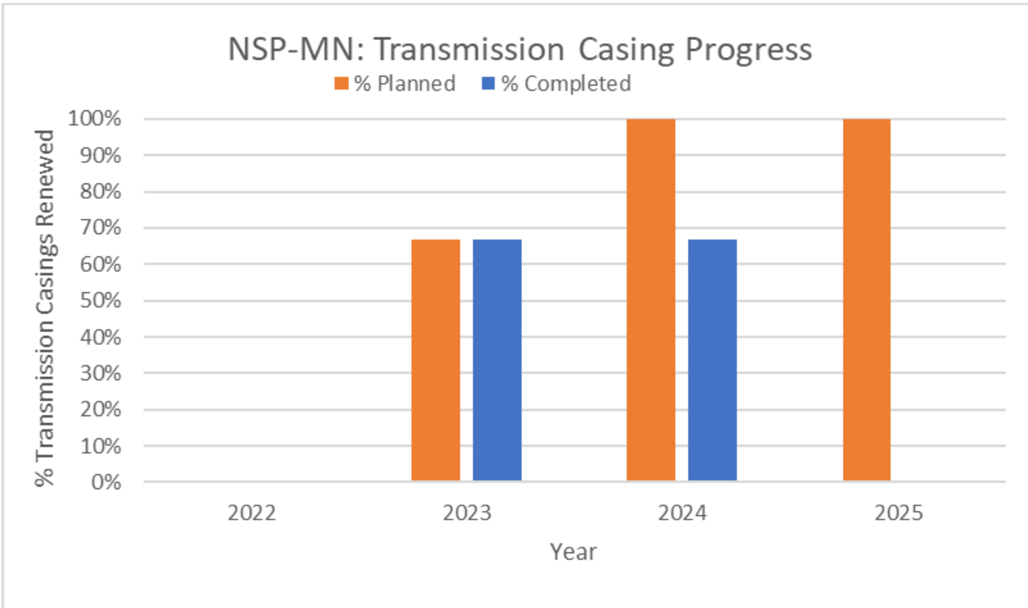
	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$2.10	$3.70	$1.60	76.19%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: Variance for Hardman due to revised contractor unit prices, higher than anticipated groundwater levels, and the requirement by the city to repave the road.

O&M: None.

Figure 4
Percentage of Casings Remediated



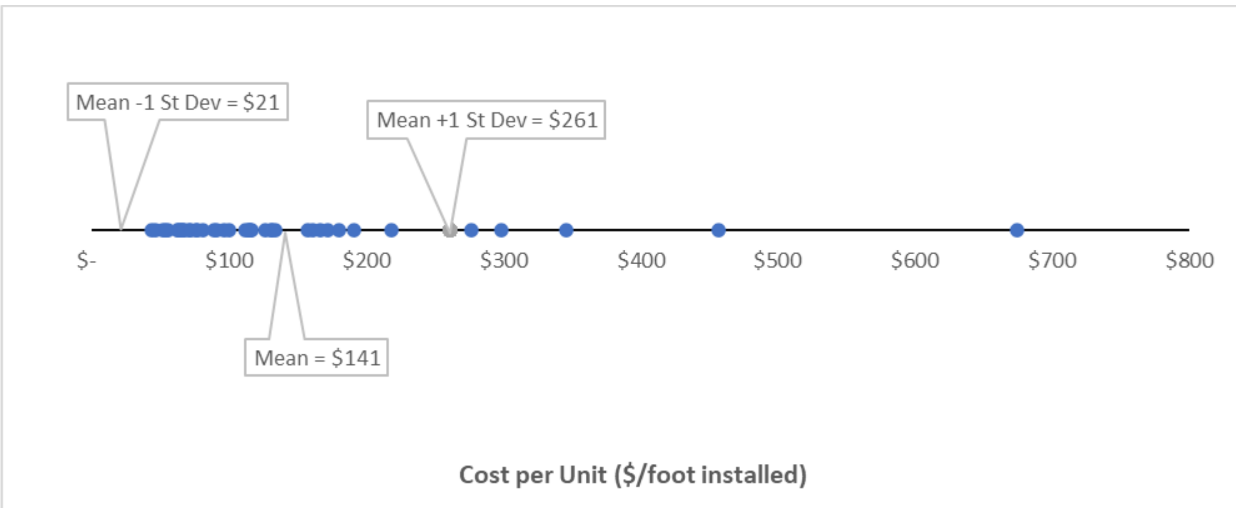
As shown in Figure 4 above, we completed two casing projects in 2023. We ran into some constructability issues with the remaining identified Transmission casing so we are now looking at revised scope with design in 2024 and construction in 2025.

B. DIMP Metrics

49 CFR Part 192.1007(e) currently requires performance metrics for DIMP, including the total number of leaks either eliminated or repaired, categorized by cause.

1) Poor Performing Main Replacement

Figure 5
2023 NSPM Poor Performing Main Replacement Projects
Cost per Unit ($/foot installed)



The cost metric shown in Figure 5 above depicts the distribution of average cost per foot for poor performing main replacement projects. Unit costs may vary for many reasons including differences in soil conditions, paving requirements, traffic-control requirements, and permit restrictions. In general, projects that the Company considers urban construction exhibit similar traits: congested right of way that necessitates we utilize more or exclusively open trenching and hydrovac instead of directional boring to avoid damaging and safely excavating around existing facilities. Additionally, these projects often require additional concrete and asphalt restoration that impact productivity, equipment, and cost. With a heightened focus on safety procedures, many "non-urban" projects are utilizing a hydrovac approach to illuminate discrepancies or risks within the field. There were five projects in 2023 that exceeded the mean cost per foot plus one standard deviation ($127 per foot).

Oakdale Ave
This project is in a very congested area with larger diameter pipe, concrete and asphalt restoration was greater than typical and vacuum excavation was needed which led to an increase in the project costs.

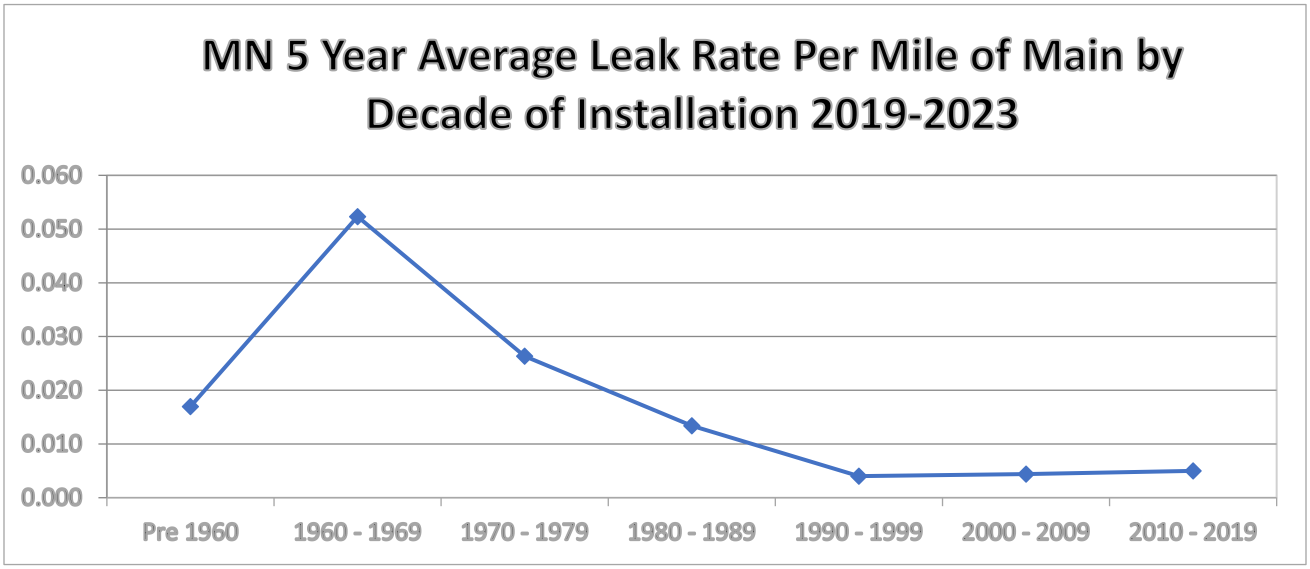
7th St NW
This project is in a highly congested area, requiring larger diameter pipes and more extensive concrete and asphalt restoration than usual.

Water St
This project was in an urban setting with larger diameter pipe, asphalt and concrete restoration was greater than typical. A vacuum excavation was needed for most of the installation and higher cost per foot.

Arlington Ave
This project is in a very congested area with a large diameter pipe. Vacuum excavation was needed for the entire project. There was asphalt and concrete restoration needed which led to an increase in the project costs.

Gary Pl
This project is located in a highly congested area and involves a large diameter pipe. Vacuum excavation was required throughout the entire project. Additionally, significant asphalt and concrete restoration was necessary, resulting in increased project costs.

Figure 6
Leak Rate by Vintage



Leak rates for assets installed in 2020 through 2023 were not included in Figure 6 above, as a five-year average will not be available until 2025. There were 16 underground, non-excavation damage leaks recorded for assets installed in 2020 through 2023, corresponding to a four-year leak rate of 0.019 leaks per mile.

2) Poor Performing Service Replacement

Figure 7
2023 Cost per Unit ($/service installed)

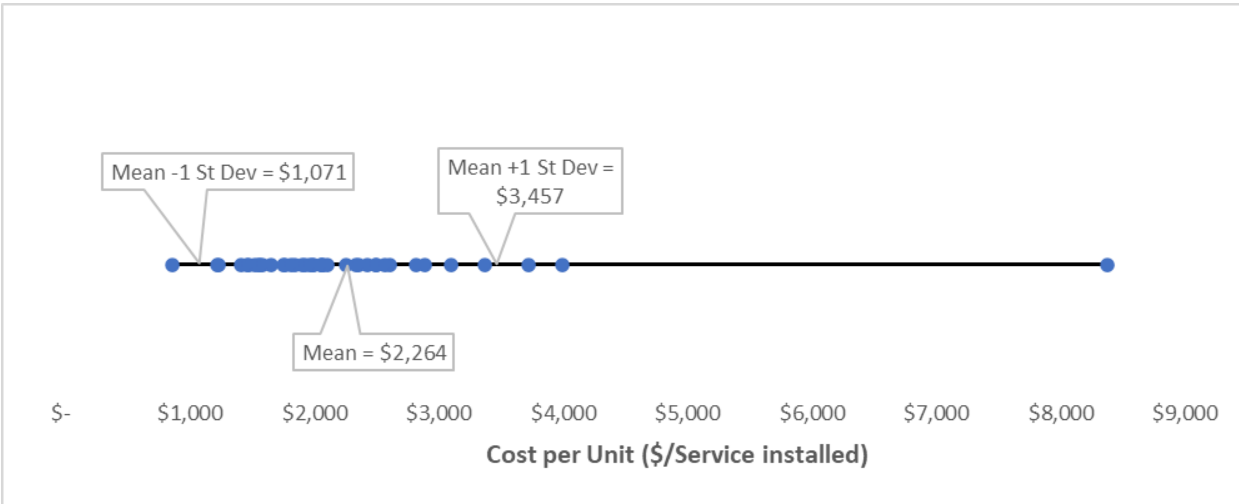


Figure 7 above depicts the distribution of cost per average service installation for poor performing services installations. Due to material constraints, many gas services were tied over to new main project. This approach creates construction cost and restoration charges without any footage to account for as a result increases the cost per unit. There were three projects that fell above the mean cost per gas service plus one standard deviation ($3,180/service) and one project that fell below the mean cost per gas service plus one deviation

1st St S

The services for this project are situated in a densely populated area, which necessitated the use of hydrovac due to the greater amount of concrete and asphalt involved. Additionally, these services are longer than usual.

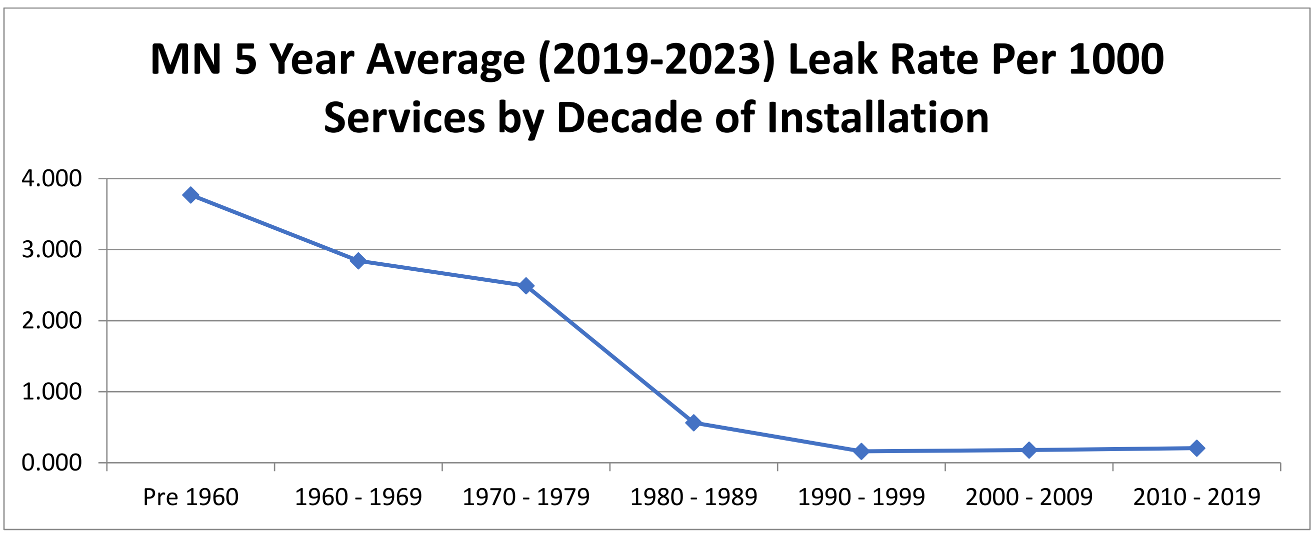
14th St S & 9th Ave S

The services for this project are in a highly populated area, requiring the use of hydrovac because of the increased amount of concrete and asphalt present. Moreover, these services are longer than typical.

7th St NW
The services for this project are situated in a rural environment with optimal plowing conditions, enhancing installation efficiency. Additionally, these services are shorter in length than usual.

Water St.
The services for this project are in an industrial area, requiring the use of hydrovac because of the increased amount of concrete and asphalt present. Moreover, these services are longer than typical and larger pipe was used for more commercial customers.

Figure 8
Leak Rate by Vintage



3) Distribution Intermediate Pressure ("IP") Pipeline Integrity Assessment

2023 Estimated vs. Actual Project Costs
($ Millions)

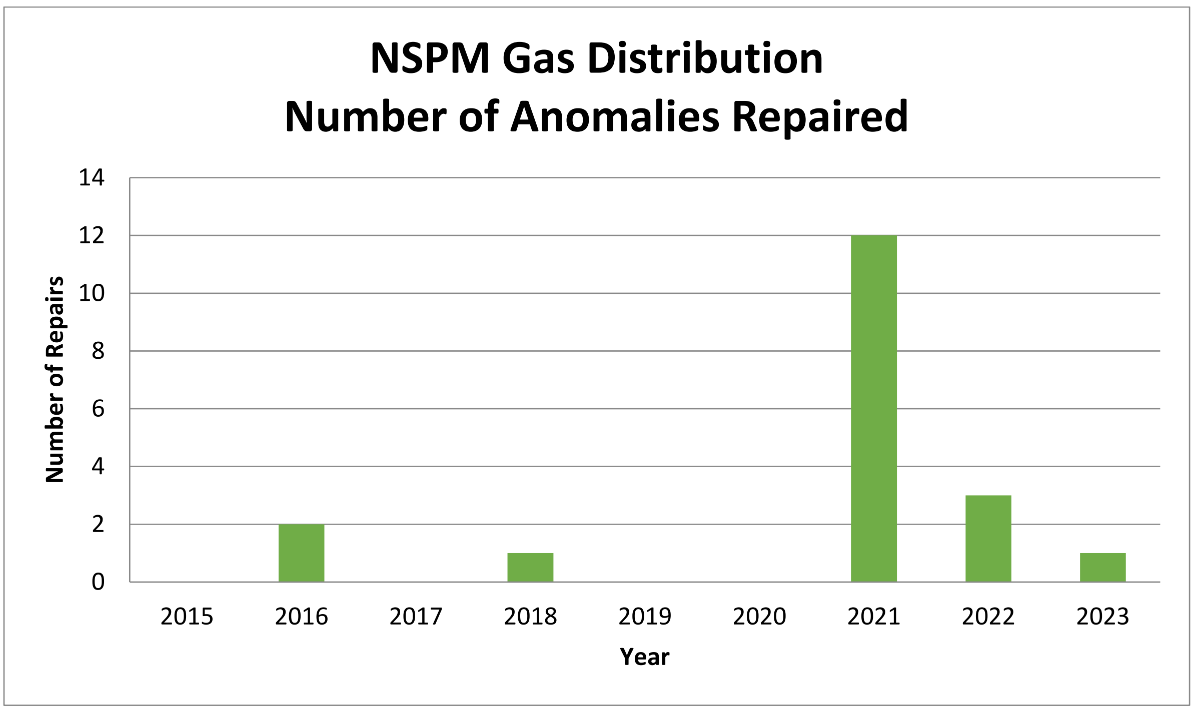
	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$1.69	$2.24	$0.55	32.68%	$0.25	$0.25	($0.00)	-1.62%

Variance Explanation

Capital: The increase is primarily due to the county requiring additional asphalt restoration associated with County Rd B, emerging Watab IP Line project, and the distribution reg station on the East County Line (East segment).

O&M: None.

Figure 9
Number of Anomalies Repaired



Anomaly repairs are expected to vary from year to year as different pipelines are inspected or assessed. However, the goal of each excavation is to remediate all potential anomalies and identify trends on each line to properly assess and mitigate integrity risks.

Since 2015, the Company has completed 30 excavations as part of the Gas Distribution Integrity Assessment project. Through these excavations the Company has identified anomalies.

Table 3 below shows the anomalies repaired, by type of anomaly repaired.

Table 3
DIMP Repairs by Anomaly Type

Anomaly Type	Number of Repairs
External Corrosion	4
Internal Corrosion	0
Stress Corrosion Cracking	0
Manufacturing	5
Construction	9
Equipment	0
Third-Party Damage	1
Incorrect Operations	0
Weather and Outside Force	0
Total	**19**

4) Distribution Valve Replacement

2023 Estimated vs. Actual Project Costs

($ Millions)

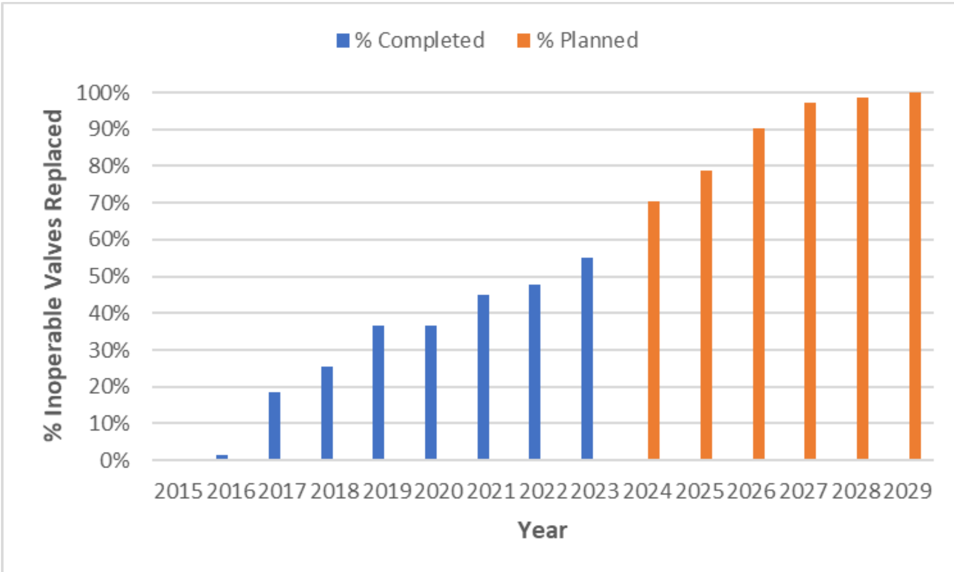
	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	0.37	0.51	$0.14	38.73%	$0.00	$0.00	$0.00	0.00%

<u>Variance Explanation</u>

Capital: The variance is driven by an increase in material costs compared to the original estimate from 2022.

O&M: None.

Figure 10
Percentage of Inoperable Valves Replaced



As shown in Figure 10 above, approximately 70 percent of the Company's inoperable valves have been replaced. The Company's distribution valve replacement plan projects 100 percent of inoperable valves will be replaced by 2029. Please note the Company has forecasted spend in 2028 and 2029 in the event that additional inoperable valves are identified in the future.

Figure 11
Reduction in Potential Customer Outage

Geographic Area (by Division)	Reduction in Potential Customer Outage
Newport	33,156
Southeast	907
St. Paul	24,336

As shown in Figure 11 above, the installation of new distribution isolation valves has created a reduction in potential customer outages. In the case of an emergency, this gives the Company the ability to isolate a reduced number of customers in an area and therefore impacts fewer customers.

5) Casing Renewal

2023 Estimated vs. Actual Project Costs
($ Millions)

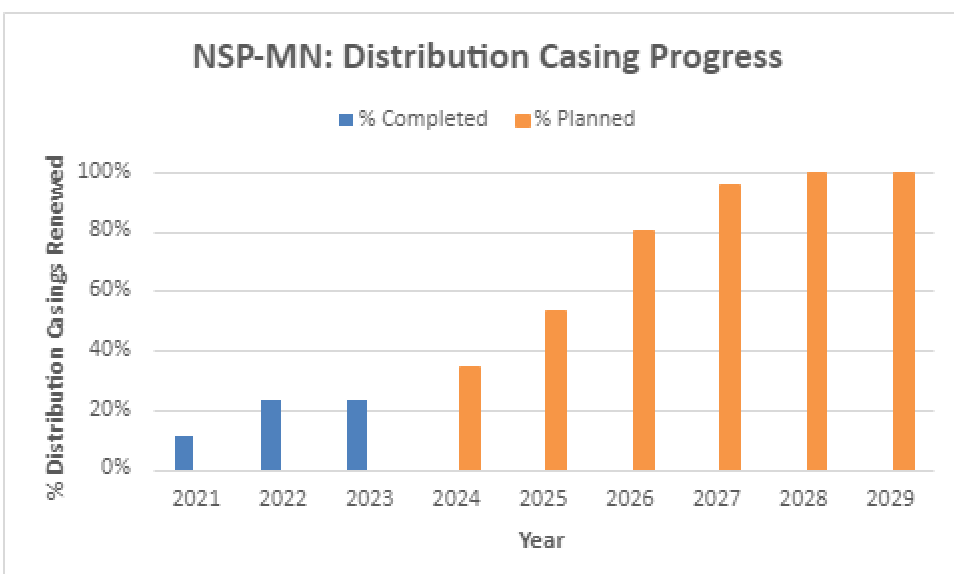
	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance	2023 O&M, As Filed	2023 O&M Actuals	Variance	% O&M Variance
Capital / O&M Expenditures	$1.67	$0.33	($1.34)	-80.17%	$0.00	$0.00	$0.00	0.00%

Variance Explanation

Capital: The primary driver for the variance is due to the complexity of the engineering bore profile and the permitting process which has led the delay of one the shorted casing at 35E & Arlington, pushing its construction to 2024.

O&M: None.

Figure 12
Percentage of Casings Remediated



As shown in Figure 12 above, approximately 23 percent of the Company's distribution casings have been renewed. The Company's plan projects 100 percent will be renewed by 2029.

C. Mandated Relocations Metrics

2023 Actual Project Costs
($ Millions)

Mandated Relocation Program	2023 Capital, As Filed	2023 Capital Actuals	Variance	% Capital Variance
Mandated Relocations	$14.02	$20.12	$6.10	43.5%

<u>Variance Explanation</u>

Capital: The $6.10 million increase was driven primarily by $10.9 million of emerging mandated relocation projects and updated forecasts of $1.2 million on Stillwater County Rd 5, May Township, and Metro Gold Line projects. This increase was offset by reductions in estimated costs and completion in 2023 for the Dawn Ave project ($0.7 million), and estimated cost of routine relocation projects ($3.4 million).

O&M: None.

Figure 13
Number of Planned vs. Actual Discrete Mandated Relocations

NSP-MN Mandated Relocations	Planned as of 2023 GUIC Rider Filing	Planned as of 2024 GUIC Rider Filing	2023 Actual Mandated Relocations
2023	5	20	26

As shown in Figure 13 above, there were 5 discrete projects identified at the time the 2023 GUIC Rider Filing was submitted. Due to the nature of these projects, the Company was notified of additional discrete projects in 2023 that were not captured in the forecast for the 2023 GUIC Rider Filing.

Certificate of Service

I, Victor Barreiro, hereby certify that I have this day served copies or summaries of the foregoing documents on the attached list(s) of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

or

xx electronic filing

Docket No. G002/M-23-457

Docket No. G002/GR-23-413

Xcel Energy Miscellaneous Gas Service List

Dated this 31st day of October 2024

/s/

____

Victor Barreiro
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_23-457_M-23-457
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-457_M-23-457
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-457_M-23-457
Allen	Barr	allen.barr@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Ste 1400 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-457_M-23-457
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Robert S.	Carney, Jr.			4232 Colfax Ave. S. Minneapolis, MN 55409	Paper Service	No	OFF_SL_23-457_M-23-457
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_23-457_M-23-457
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_23-457_M-23-457
George	Crocker	gwillc@nawo.org	North American Water Office	5093 Keats Avenue Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_23-457_M-23-457
Joseph	Dammel	dammel@fresh-energy.org	Fresh Energy	408 Saint Peter St Ste 350 St. Paul, MN 55102	Electronic Service	No	OFF_SL_23-457_M-23-457

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Dornfeld	Richard.Dornfeld@ag.state.mn.us	Office of the Attorney General-DOC	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-457_M-23-457
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-457_M-23-457
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 55101-2198	Electronic Service	No	OFF_SL_23-457_M-23-457
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_23-457_M-23-457
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_23-457_M-23-457
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 55402-1425	Electronic Service	No	OFF_SL_23-457_M-23-457
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-457_M-23-457
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_23-457_M-23-457
Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S. Eighth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Suite 1400 St. Paul, MN 55101-2134	Electronic Service	No	OFF_SL_23-457_M-23-457
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_23-457_M-23-457
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Michael	Kaphing	michael.w.kaphing@xcelenergy.com	Xcel Energy	414 Nicollet Mall (401-8th Floor) Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-457_M-23-457
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_23-457_M-23-457
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_23-457_M-23-457
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_23-457_M-23-457
Peter E.	Madsen	pmadsen@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-457_M-23-457

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Greg	Merz	greg.merz@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-457_M-23-457
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_23-457_M-23-457
Kimberly	Middendorf	kimberly.middendorf@state.mn.us	Office of Administrative Hearings	PO Box 64620 600 Robert St N Saint Paul, MN 55164-0620	Electronic Service	No	OFF_SL_23-457_M-23-457
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802-2093	Electronic Service	No	OFF_SL_23-457_M-23-457
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Travis	Murray	travis.murray@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota St Ste 1400 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-457_M-23-457
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 52406-0351	Electronic Service	No	OFF_SL_23-457_M-23-457
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_23-457_M-23-457

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 55101-2131	Electronic Service	Yes	OFF_SL_23-457_M-23-457
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Peter	Scholtz	peter.scholtz@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	No	OFF_SL_23-457_M-23-457
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401-1993	Electronic Service	No	OFF_SL_23-457_M-23-457
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_23-457_M-23-457
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	No	OFF_SL_23-457_M-23-457
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 55402-4629	Electronic Service	No	OFF_SL_23-457_M-23-457

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 St. Paul, MN 55104	Electronic Service	No	OFF_SL_23-457_M-23-457
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-457_M-23-457

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristine	Anderson	kanderson@greatermngas.com	Greater Minnesota Gas, Inc.& Greater MN Transmission, LLC	1900 Cardinal Lane PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Katherine	Arnold	katherine.arnold@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Allen	Barr	allen.barr@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Ste 1400 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Olivia	Carroll	oliviac@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Joey	Cherney	joey.cherney@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street STE 1800 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_23-413_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brandon	Crawford	brandonc@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
George	Crocker	gwillc@nawo.org	North American Water Office	5093 Keats Avenue Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Richard	Dornfeld	Richard.Dornfeld@ag.state.mn.us	Office of the Attorney General-DOC	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 55101-2198	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 55402-1425	Electronic Service	No	OFF_SL_23-413_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S. Eighth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Suite 1400 St. Paul, MN 55101-2134	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Nicolle	Kupser	nkupser@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Eric	Lipman	eric.lipman@state.mn.us	Office of Administrative Hearings	PO Box 64620 St. Paul, MN 55164-0620	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Peter E.	Madsen	pmadsen@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Stephen	Melchionne	stephen.melchionne@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street, Ste. 1400 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Greg	Merz	greg.merz@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Kimberly	Middendorf	kimberly.middendorf@state.mn.us	Office of Administrative Hearings	PO Box 64620 600 Robert St N Saint Paul, MN 55164-0620	Electronic Service	No	OFF_SL_23-413_Official CC Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802-2093	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Travis	Murray	travis.murray@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota St Ste 1400 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-413_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 52406-0351	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Greg	Palmer	gpalmer@greatermngas.com	Greater Minnesota Gas, Inc. & Greater MN Transmission, LLC	1900 Cardinal Ln PO Box 798 Faribault, MN 55021	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND	81 E Little Canada Road St. Paul, MN 55117	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 55101-2131	Electronic Service	Yes	OFF_SL_23-413_Official CC Service List
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Peter	Scholtz	peter.scholtz@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401-1993	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_23-413_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	Yes	OFF_SL_23-413_Official CC Service List
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 55402-4629	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Suzanne	Todnem	suzanne.todnem@state.mn.us	Office of Administrative Hearings	600 Robert St N PO Box 64620 St. Paul, MN 55164	Electronic Service	Yes	OFF_SL_23-413_Official CC Service List
Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Avenue West Suite 515 St. Paul, MN 55104	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Joshua	Weir	jweir@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-413_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
George	Crocker	gwillc@nawo.org	North American Water Office	5093 Keats Avenue Lake Elmo, MN 55042	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 55101-2198	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP	Suite 1750 220 South Sixth Street Minneapolis, MN 55402-1425	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802-2093	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 55101-2131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Christine	Schwartz	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 55401-1993	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Gas_Xcel Miscl Gas