



INVESTOR-OWNED UTILITY GAS DISTRIBUTION CAPITAL EXPENDITURES: A STUDY ON THE POTENTIAL BILL IMPACTS OF BUSINESS-AS-USUAL INVESTMENT IN MINNESOTA



CITIZENS UTILITY BOARD
Empowering Minnesota Consumers

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Citizens Utility Board of Minnesota

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FROM THE CITIZENS UTILITY BOARD OF MINNESOTA

Dear Reader:

The cost of natural gas delivered to homes and businesses continues to rise year over year, and Minnesota ratepayers are feeling the pain. Utility data shows that the number of households behind on their gas bills is up, and, on average, those households owed nearly twice as much in 2022 as they did in 2019.

While many ratepayers struggle to keep up with their bills, utility companies continue to commit ever-larger sums into system investments – **investments that translate to ever-higher costs for ratepayers.**

The Citizens Utility Board of Minnesota (CUB) commissioned this study to examine the drivers, trajectory, and household impact of rising natural gas rates. CUB engaged DHInfrastructure to examine publicly available data and help us understand the ratepayer impact of continually increasing spending by Minnesota's three largest gas utilities: CenterPoint Energy, Xcel Energy, and Minnesota Energy Resources (MERC).

The findings are stark.

The combined annual investments in infrastructure made by these three utilities have more than tripled, from \$218 million in 2013 to \$700 million in 2022. In total, these investments have more than doubled the overall value of the utilities' gas delivery infrastructure over the past decade.

Despite having some of the lowest safety risks of any gas distribution systems in the country, these companies' combined capital expenditures will top \$1 billion per year by 2030 if they are to hit their corporate investment targets. Under a conservative projection, **the companies will be recovering approximately \$3 billion per year from ratepayers by 2040** – equivalent to purchasing nearly three U.S. Bank Stadiums every year.

Utility companies make investments with the assurance that they will be paid back over time, with an added return on equity. Investor-owned companies are inherently beholden to their investors, and investor-owned utilities must prioritize generating this return. That's why utility companies often emphasize the importance of capital investment growth when presenting financial goals to shareholders, and why Minnesota gas utility companies have set targets to inform shareholders about their plans for future investment.

For Minnesota households, utilities' investment targets translate into big bill increases. For example, CenterPoint Energy's delivery charges have nearly doubled since 2010 for the typical household – translating to an compound annual growth rate of more than 5% per year. We expect this trend to accelerate, with the typical CenterPoint customer seeing their monthly delivery charges more than triple between 2023 and 2040 in order to meet the company's investment targets. That means a **typical CenterPoint customer will pay 6.4 times more in delivery charges in 2040 than they did in 2010**. Substantial bill increases are also expected from Xcel and MERC.

These projections assume that Minnesotans will continue to use gas as they do today – but that is unlikely to happen. If Minnesota is to reach its statutory goal of net zero greenhouse gas emissions by 2050, gas usage will have to be drastically reduced.

If gas demand does indeed fall, it will only exacerbate the continuing trend of increasing rates. If gas sales decline, utilities will have to increase base rates even faster to recoup their investments over fewer units of gas sold. Increased gas rates might spur more customers to switch to electricity for heating, water heating, cooking, and clothes drying, further reducing gas utility sales, and further driving up rates for the customers that remain on the system – an effect dubbed the “utility death spiral.” **Those who cannot manage or afford to transition their homes and apartments away from gas could be stuck with astronomical bills.**

Utility investments are long-term commitments, typically paid down over more than 30 years (and as long as 60 years). Decisions made today commit ratepayers to higher bills for decades to come.

This report should raise questions for Minnesotans, utility regulators, and the utility companies themselves. Especially given the uncertainty about the future of natural gas usage, we must think carefully about these investments to ensure that we are not saddling future generations with billions of dollars in gas infrastructure debt.



Annie Levenson-Falk
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EXECUTIVE SUMMARY

The Citizens Utility Board of Minnesota (CUB) engaged DHInfrastructure to undertake a study on the capital expenditures being made by the state’s local gas distribution companies (LDCs). The annual investment in utility infrastructure by the state’s LDCs has grown quickly in recent years. CUB specifically wanted to understand how a continuation of the accelerated pace of investment might affect residential customer bills in the future.

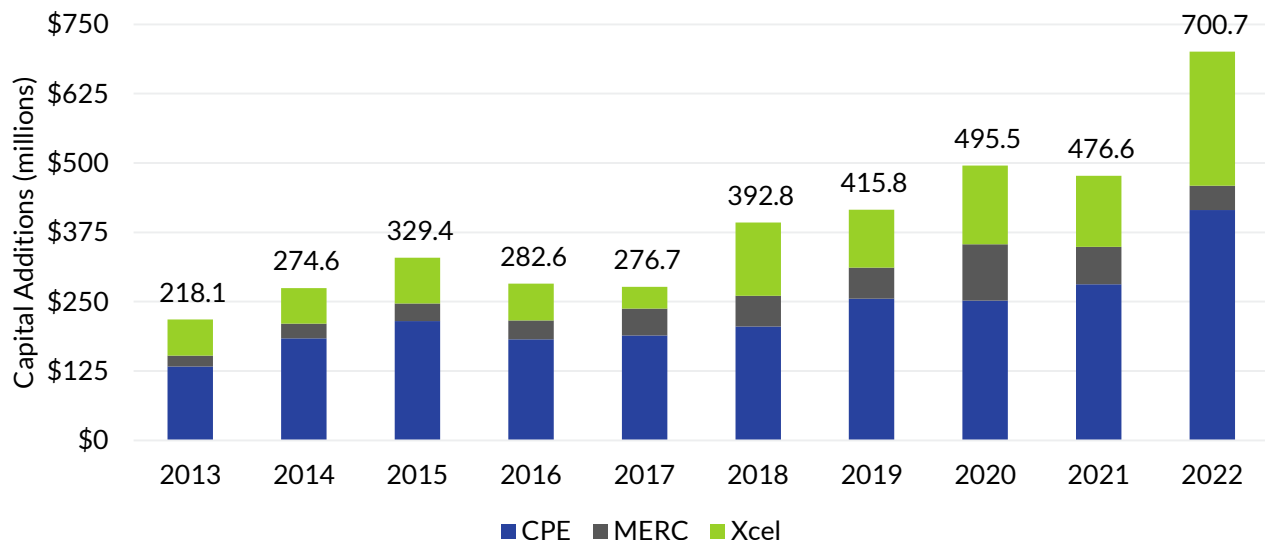
The study focuses on the state’s three largest investor-owned utilities (IOUs): CenterPoint Energy (CPE), Minnesota Energy Resources Corporation (MERC), and Xcel Energy (Xcel) (collectively, the “Minnesota LDCs”). It begins with an overview of the recent trends in gas infrastructure investment by the Minnesota LDCs and discusses some of the factors that have driven investment in gas infrastructure. To understand the potential impact of sustained high levels of capital investment on residential base rates, this study projected future capital additions, revenue requirements, and typical bills through 2040, based on information and assumptions taken from presentations to the Minnesota LDC’s corporate shareholders, annual reports, and other regulatory filings.

Below we summarize the findings and results of the study.

Minnesota’s three largest gas companies have more than tripled annual capital expenditures since 2013.

Over the past 10 years, the Minnesota LDCs have made capital investments in capital infrastructure (commonly referred to as *utility plant* or *utility plant-in-service*) at steadily increasing rates, as shown in Figure 0.1.

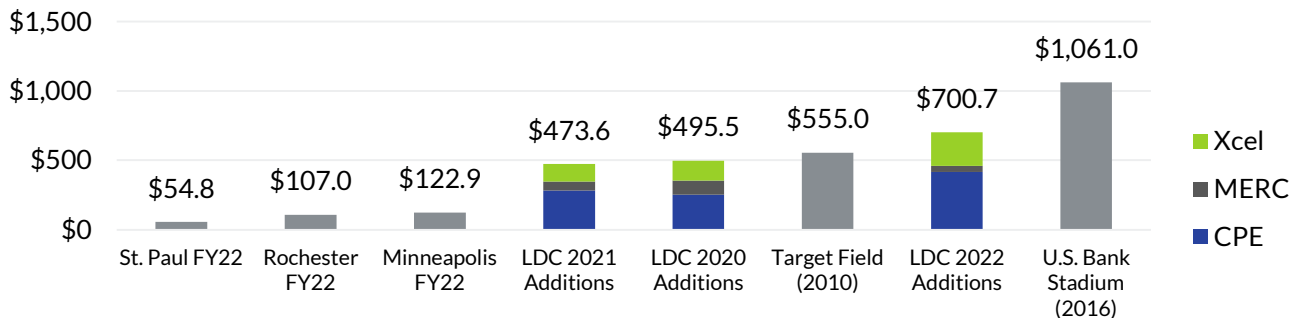
Figure 0.1: Natural Gas Utility Capital Investment in Minnesota, 2013–2022



Sources: Gas Jurisdictional Annual Reports for each utility, 2013 to 2022. See Minnesota Public Utilities Commission, “MN DOC Efiling,” available <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showeDocketsSearch&showEdocket=true>, dockets 14-04, 15-04, 16-04, 17-04, 18-04, 19-04, 20-04, 21-04, 22-04, and 23-04.

The combined capital expenditures made by the Minnesota LDCs every year represent some of the largest capital initiatives undertaken statewide. In 2022 alone, the more than \$700 million in capital additions made by the Minnesota LDCs is more than what was spent to build Target Field in 2010 and more than double the combined \$285 million in capital budgets approved by Minneapolis, Rochester, and St. Paul for fiscal year 2022, as shown in Figure 0.2.

Figure 0.2: Comparison of 2022 LDC Capital Additions to other Minnesota Capital Outlays (in millions)



While these capital additions by the Minnesota LDCs are initially funded through private investment, Minnesota ratepayers ultimately bear the costs.

The capital investments made by the Minnesota LDCs since 2013 have more than doubled the financial book value of the infrastructure these utilities use to provide gas delivery services. From 2013 through 2022, CPE’s utility plant-in-service has grown at a rate of 9.1 percent annually, MERC’s has grown at a rate of 8.4 percent annually, and Xcel’s has grown at a rate of 6.9 percent annually.

These annual increases in utility plant are significant because increases in utility plant-in-service have corresponding impacts on the base rates that LDCs charge to their customers. IOUs like CPE, MERC, and Xcel operate under a regulatory structure called “rate-of-return” regulation wherein the Minnesota Public Utility Commission (PUC) sets base rates at levels that are intended to allow utilities the opportunity to recover a “return of” their investments in utility plant over time (in the form of depreciation charges) and a “return on” their investment equal to a regulator-approved rate of return times the value of the utility’s rate base (the undepreciated portion of its utility plant-in-service plus other non-plant capital assets).

Ratepayers are paying higher base rates for investments in gas distribution systems that are already among the safest in the country.

Investment in infrastructure is understood to be an essential part of an LDC’s responsibility in providing safe, adequate, and efficient utility gas services. However, it is also expected that services be provided at fair and reasonable rates. Ultimately, to achieve both objectives, the pace of investment needs to find a balance where the utility’s safety and service obligations can be met at something close to the lowest cost.

The question when considering the recent expenditures made by the Minnesota LDCs is whether these represent the lowest cost investment strategy the utilities could have deployed to provide safe, adequate, and efficient gas delivery services. One of the pivotal considerations when developing a capital investment plan is

the level of risk¹ on an LDC's delivery system. Factors that increase the likelihood of a failure event, and thereby the risk on a system, include the age of the infrastructure, the pipe materials on the system, and the prevalence of system leaks. It is reasonable to expect that LDCs with higher risk factors might require higher or increasing levels of capital investments to address the factors contributing to increased risk.

Research on the Minnesota LDCs shows their delivery systems already have some of the lowest risk of any LDC nationally. These reduced risk factors include the following:

- **Lower counts of leak-prone mains and services.** The Pipeline and Hazardous Materials Safety Administration (PHMSA) provides directives to LDCs on the types of pipeline materials that have been identified as leak-prone and should be prioritized for replacement. Compared to other parts of the country, the Minnesota LDCs have much lower levels of unprotected steel, cast iron, and copper pipes for which PHMSA has called for priority replacement. The Minnesota LDCs do have certain types of plastic pipe called "Aldyl-A" pipe on their systems that has been identified by PHMSA as a class of pipe for operators to monitor and possibly prioritize replacement.²
- **Below average leak rates.** Monitoring the number and rate of leaks (such as leaks per mile or leaks per 1,000 services) over time can provide valuable insights into the overall health of a gas distribution system. The leak rates in 2022 for CPE (0.0140 leaks per mile), MERC (0.0075 leaks per mile), and Xcel (0.0139 leaks per mile) are not only well below the national average (0.0536 leaks per mile), but they are also among the lowest leak rates in the entire country. Service leak rates in Minnesota are also around or below the national average. One exception is the service leak rates for CPE that have been above the national average for each of the past ten years.
- **Newer pipeline infrastructure.** PHMSA has also advised operators to focus on replacement of older pipelines based on the premise that improvements in pipe manufacturing, design, construction, and maintenance practices have improved over time, making older pipes higher risk than newer pipes. Nationally, 34 percent of mains and 25 percent of services were installed prior to 1980. The proportion of pre-1980 pipe for CPE (24 percent mains, 16 percent services), MERC (24 percent mains, 1 percent services*), and Xcel (8 percent mains, 7 percent services) are all below these national averages.³

It might be reasonable to conclude that the lower risk factors identified for the Minnesota LDCs are a product of the heightened investment activities undertaken over the past ten years. There are cases for and against this conclusion. CPE has removed more than 450 miles and Xcel more than 150 miles of unprotected/bare steel main and cast iron between 2013 and 2022. These activities have certainly contributed to the low count of leak-prone pipe materials. However, even back in 2012 when those miles of pipe were on CPE and Xcel's

¹ Risk on a pipeline is defined as a measure of potential loss in terms of both the likelihood (or frequency of occurrence) of an event and the magnitude of the consequences from the event.

² Because operators do not report plastic pipe by type to PHMSA it was not possible to include this category of pipe in the leak-prone comparative analysis. The directives from PHMSA on Aldyl-A pipe have been different from those on cast iron and unprotected steel in that only certain vintages (pipe manufactured pre-1973) have been identified as the priority, while conversely it is generally understood that all cast iron and unprotected steel should be considered obsolete. Then, for the vintages identified, the emphasis has been to monitor the performance of known Aldyl-A pipes and prioritize replacement when evidence suggests the infrastructure is failing at a faster rate. This is because the failure of Aldyl-A can depend on the specific environmental conditions of the utility.

³ The 1 percent of pre-1980 services for MERC may be understated because it reports that it does not know the age of 57 percent of its services.

systems, the proportion of leak-prone cast iron and unprotected steel mains (3.9 percent for CPE, 1.9 percent for Xcel) was still below today's national average (4.9 percent).

The historical leak rates on both services and mains for all the companies also do not support the case that the current reduced levels of leaks are the result of recent investment choices. Leak rates on both services and mains for all three companies were mostly flat over the entire 2013 to 2022 time period. Had the leak rates started higher and fallen, this might have indicated that recent investments were responding to a specific urgent problem and that the current lower leak rates are evidence the problem has been or is being addressed through capital investments.

Despite the relatively lower risk on their distribution systems, the Minnesota LDCs indicate to investors that they will sustain the same accelerated levels of capital investment for the foreseeable future.

It would seem reasonable to expect that, given the lower relative risk on the Minnesota LDCs' systems, there would be less need for investment over the coming years and that the level of capital expenditures would not continue to increase at the same accelerated rates.

Based on what the companies have told their investors, a slowdown in investment does not appear to be in the plans. When executives from the parent companies of the Minnesota LDCs give updates on their financial performance to investors it is common for them to set long-term targets for compound annual growth rates (CAGR) in rate base (which, as explained above, includes the undepreciated value of utility plant-in-service). Recent targets from investor presentations with CAGR targets relevant to the Minnesota LDCs include the following:

- **CPE:** 10.95 percent CAGR through 2026
- **MERC:** 7.4 percent CAGR through 2027
- **Xcel:** 6.0 percent CAGR through 2026 followed by 6.5 percent CAGR through 2031

LDCs hit these rate base targets by making capital investments in utility plant-in-service. The key phrase to understand how these targets provide insight into future investment plans is that these are "compound" growth targets. This phrase implies the objective is to grow rate base by approximately the same percentage or more every year. Because each year's investment in utility plant increases rate base, for compound growth to occur the level of investments needed every year to grow rate base at the same rate must be more than the previous year's level of investments. If the number of investments were to fall from one year to the next, or even stay the same, that would result in a reduced rate of growth in rate base.

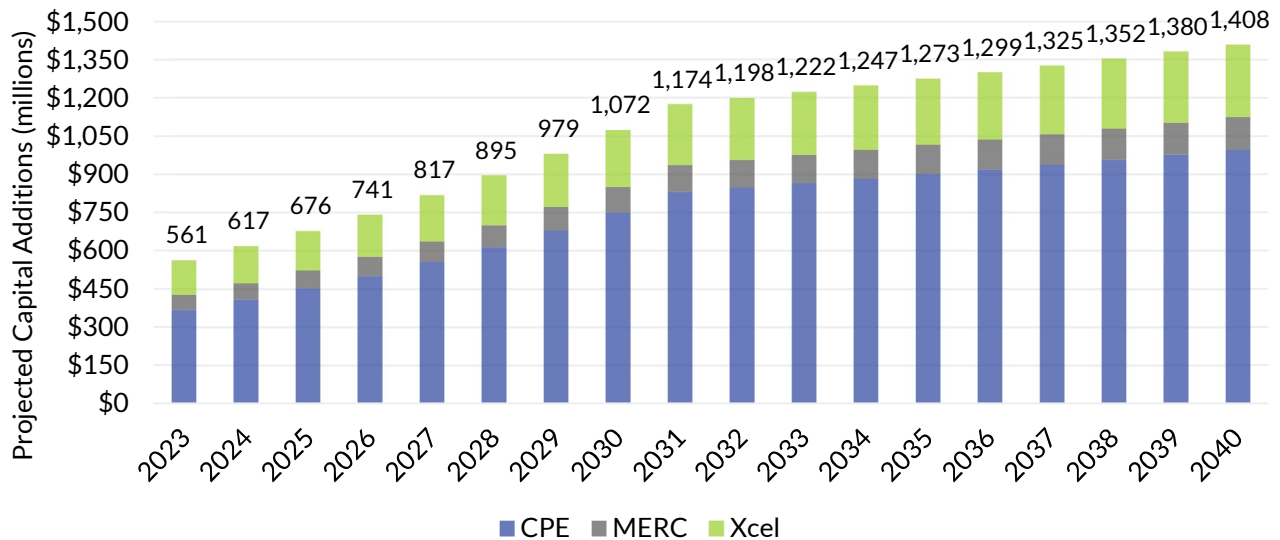
What the parent companies of the Minnesota LDCs are telling us and their investors when they set these rate base targets is that they have no plans to slow down the rate of capital investment.

If the Minnesota LDCs continue to make investments at the levels needed to hit their corporate rate base targets, this study projects the combined capital expenditures for all three companies will exceed \$1 billion per year by 2030, and total capital spending in Minnesota from 2023 to 2040 will be almost \$20 billion.

This study projected future capital additions through 2040 based on the Minnesota LDCs' own rate base growth goals. A conservative "hybrid" approach was used, growing rate base at these targeted investment rates through 2031 and at the rate of inflation thereafter.

Projections using this approach show CPE making nearly \$1 billion of capital additions in 2040, with MERC making \$127 million and Xcel making \$286 million in 2040. In total, capital additions by the Minnesota LDCs are projected to be more than \$1.4 billion in 2040 alone, as shown in Figure 0.3. The total capital expenditures for the 2023 through 2040 period are forecasted to be \$19.24 billion; an average of \$1.07 billion per year.

Figure 0.3: Projected Natural Gas Utility Capital Investment in Minnesota, 2023–2040

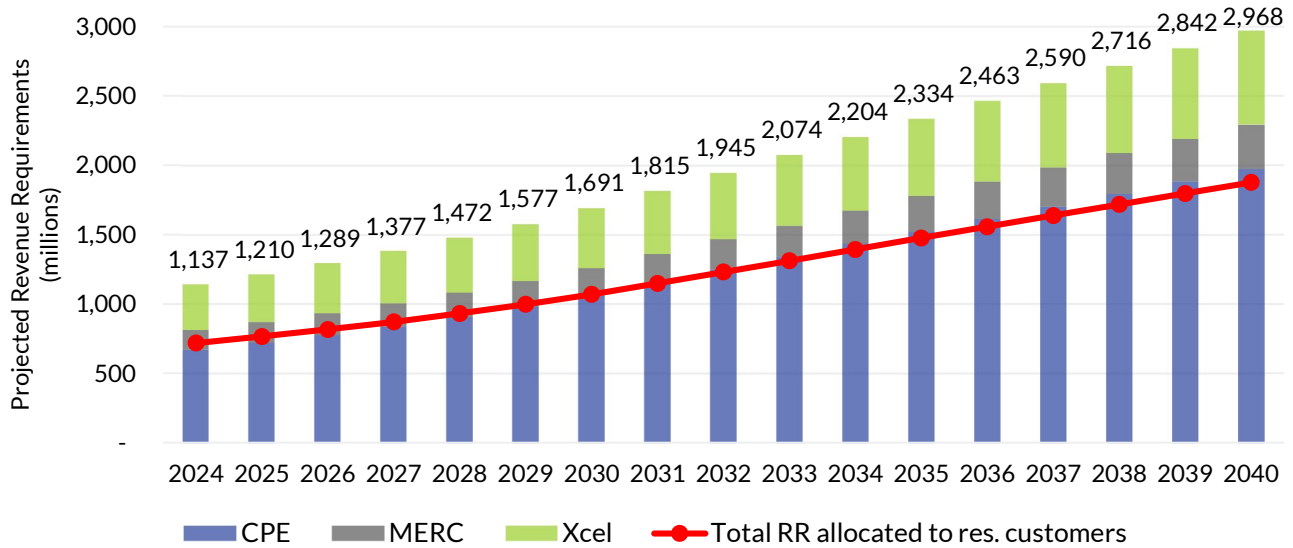


Source: Consultant projections.

The projected growth in capital additions means that the Minnesota LDCs’ revenue requirements—the amount of money they recover from customers through base rates—could grow to nearly \$3 billion by 2040.

Forecasts for capital additions and rate base were used to develop projections for the annual revenue requirements of each LDC. These corresponding projections for revenue requirement in this study show CPE’s revenue requirement growing to nearly \$2 billion in 2040, while MERC’s projected revenue requirement grows to nearly \$320 million and Xcel’s grows to \$676 million. In total, the Minnesota LDCs will need to recover nearly \$3 billion in revenue from customers in 2040 (as shown in Figure 0.4), including more than \$1.87 billion from residential customers (residential customers are allocated between 62 and 65 percent of the revenue requirement, depending on the company).

Figure 0.4: Projected Revenue Requirements, 2024–2040



Source: Consultant projections.

These higher revenue requirements would need to be recovered from customers through increasingly higher base rates that will have significant impacts on monthly customer bills...

These high levels of capital investment and revenue requirements are projected to result in considerably higher monthly bills. Table 0.1 shows that typical residential monthly delivery charges (the cost of delivering the gas to the customer, excluding the cost of the gas as a commodity) have already increased substantially since 2010 and are projected to at least double between 2023 and 2040. The projected monthly delivery charge in 2040 is more than six times higher for CPE than it was in 2010, while both MERC and Xcel have typical monthly delivery charges more than three times higher than they were in 2010. These are only the base rate charges customers pay for delivering natural gas to their premises. Actual bills will be higher because they will include the cost of the gas itself.

Table 0.1: Historical and Projected Typical Residential Monthly Delivery Charges, Selected Years 2010–2040

LDC	2010*	2023*	2030**	2035**	2040**	Change since 2023	Change since 2010
CPE	\$19.31	\$37.12	\$66.56	\$95.76	\$124.17	↑ 3.3X	↑ 6.4X
MERC	\$21.55	\$38.14	\$47.49	\$62.25	\$77.58	↑ 2.0X	↑ 3.6X
Xcel	\$24.04	\$33.04	\$52.90	\$67.12	\$81.40	↑ 2.5X	↑ 3.4X

*Bills are calculated using actual historic base rates; **Bills are calculated using projected base rates; Source: Consultant projections.

...which could be even higher, particularly for vulnerable customers, if gas usage declines, requiring costs to be recovered over fewer sales.

This study also considered the future of natural gas given Minnesota’s greenhouse gas emission reduction goals. Base rates and typical monthly bills were projected under an alternative scenario—based on a report completed with input from the state’s natural gas utilities—where natural gas serves as a backup to space

heating using electric heat pumps. This scenario sees a 76 percent reduction in gas sales by 2050; to meet the same revenue requirement projections described above, base rates would have to increase substantially.

The average household would use less gas in this scenario, offsetting the increase in gas rates and keeping their monthly bills the same as in the base case. However, households that are unable to afford the initial cost of energy efficiency upgrades and electric heating would continue using gas as they do today. Consequently, by 2040, those households would experience monthly gas bills that are 1.66 to 1.7 times higher than under the base case.

The magnitude of these potential bill increases in the future should be concerning given that there is already evidence that residential customers are unable to pay their bills today.

This study has projected substantial rate increases at a time when many customers are already having difficulty paying their bills. Since 2019, the number of residential gas customers falling behind one month or more on their gas bills has increased by 1.5 percent at CPE and 3.2 percent at MERC, and the average amount owed by customers in arrears has more than doubled at both companies.⁴ These problems may be exacerbated in the future if space heating transitions to being primarily fueled by electricity instead of natural gas.

This study points to the need for careful consideration of whether the Minnesota LDCs' increasing rates of capital investment are in the public interest.

The study relies on publicly available data and information to present a scenario of the annual future gas capital investments and the corresponding residential bill impacts that is based on what the Minnesota LDCs themselves have presented to their investors and state and federal regulators. We hope that it may be used by the state's policy makers, regulators, and other stakeholders to inform their considerations regarding gas infrastructure investment in Minnesota's future. The decisions made today on gas infrastructure investment will have long-term impacts on the state's policy goals and the affordability of essential energy services. We hope this study allows for a critical discussion on these urgent decisions.

⁴ Data on arrears for Xcel were only available at the aggregate level for combined electric and gas services. Because the numbers are not directly comparable to the other gas-only companies they were excluded from the analysis. It should be noted, however, that Xcel's aggregate electric and gas customer arrears data show the same trends of an increase in the number of residential customers one month or more behind in their bills and an increase in the arrears per customer.

SECTION 1 INTRODUCTION

This study examines the future capital investment plans of the three largest gas utility companies in Minnesota and their potential impact on future base rates.⁵ The three local gas distribution companies (LDCs) include CenterPoint Energy (CPE), Minnesota Energy Resources Corporation (MERC), and Xcel Energy (Xcel) (collectively, the “Minnesota LDCs”). These three investor-owned gas utilities make millions of dollars in capital investments in gas infrastructure every year in Minnesota that customers are expected to pay for through increasingly higher base rates. The study considers what the future rate impacts will be if gas utilities continue to make capital investments at the rates planned by the companies. The study aims to provide a set of analyses and projections to inform stakeholders’ considerations regarding continued higher levels of investment in Minnesota’s natural gas infrastructure.

The remainder of this section provides information that will be helpful to the reader to understand the context of the study and some of the fundamental concepts on gas infrastructure that may be helpful when considering its results. It begins, in Section 1.1, with a summary of the categories of capital investments in infrastructure that are made by natural gas utilities. Next, Section 1.2 presents the recent levels of capital investments made by the three largest gas utilities in Minnesota. Then, Section 1.3 identifies different factors that drive capital investment decisions made by utilities. Section 1.4 introduces some key indicators that can be used to understand the level of risk and safety performance of gas delivery systems. Finally, Section 1.5 explains the methodology and approach used in this study and previews the remainder of the report.

1.1 NATURAL GAS UTILITY PLANT-IN-SERVICE

LDCs are capital-intensive businesses, requiring significant investments in infrastructure to provide gas delivery services to their customers. Because gas utilities have limited competition within their service territories, investor- and private-owned LDCs are usually subject to regulation to prevent them from exploiting their monopoly position to increase profits by overcharging customers.⁶ The prevailing regulatory approach used by utility regulators in the United States—and the approach used in Minnesota—is known as “rate-of-return” regulation. This approach attempts to strike a balance of both protecting customers and providing a reasonable return on investment to attract investors by limiting profits to a set percentage of the utility’s investments.

Within the regulatory context, the capital infrastructure investments made by utilities are commonly referred to as *utility plant*. Investor-owned utilities (IOUs) operating under rate-of-return regulation are allowed to begin “recovering” the cost of an investment only when the plant is installed and is being used to provide services to its customers, otherwise known as *utility plant-in-service*.⁷

⁵ The term “base rates” refers to the charges or fees imposed by a gas utility company to cover the costs associated with the distribution and delivery of natural gas to customers. The commodity cost of procuring natural gas is passed through to customers through a separate charge: the purchased gas adjustment (PGA) mechanism.

⁶ This situation where high infrastructure costs make it most efficient for a single company to supply the service is known as a *natural monopoly*.

⁷ Base rates are set to allow utilities receive a “return on” the undepreciated value of their investments in the form of a return on equity and a “return of” the investment in the form of depreciation expenses. An investment is recovered through base rates until fully depreciated.

The Minnesota LDCs provide updates on their utility plant-in-service balances in Gas Jurisdictional Annual Reports (GJARs) filed annually in April or May with the Minnesota Public Utility Commission (PUC). The GJAR forms require utilities to chart utility plant across six categories intended to align with the different service functions the utilities provide:

- **Intangible plant:** Non-physical assets such as patents, copyrights, etc.
- **Production plant:** Assets and equipment used in the production of natural gas
- **Natural gas storage:** Assets used to store produced natural gas, often underground, before it enters the transmission system
- **Transmission plant:** Assets, especially mains, used for the transportation of natural gas at high pressure over long distances
- **Distribution plant:** Assets used in the delivery of natural gas to end customers, including mains (pipeline that transport gas from transmission mains), services (pipelines from distribution mains to customers' premises), and meters, among others
- **General plant:** Assets that support the overall operation of the utility, including, among others, office furniture and equipment, communication equipment, tools and laboratory equipment, etc.

Table 1.1 shows how the above categories make up the total end-of-year plant-in-service for CPE, MERC, and Xcel in 2021. Predictably, the largest investment in utility plant for the Minnesota LDCs is for the assets used to carry out the distribution function. Of the distribution category, upward of 75 percent of the utility plant investments for the Minnesota LDCs are in mains and services.

Table 1.1: End-of-Year Plant-in-Service by Category and Utility, 2021

Utility	Intangible	Production	Storage	Transmission	Distribution	General	Total (million US\$)
CPE	0.04%	1.02%	1.62%	--	87.96%	9.36%	\$3,146
MERC	5.16%	--	--	1.11%	87.48%	6.25%	\$778
Xcel	--	1.08%	3.79%	6.86%	83.54%	4.73%	\$1,623

Sources: 2021 Gas Jurisdictional Annual Reports. See MN DOC Efiling Docket 22-04.

Next, in Section 1.2, the recent trends in expenditures on utility plant made by the Minnesota LDCs will be addressed.

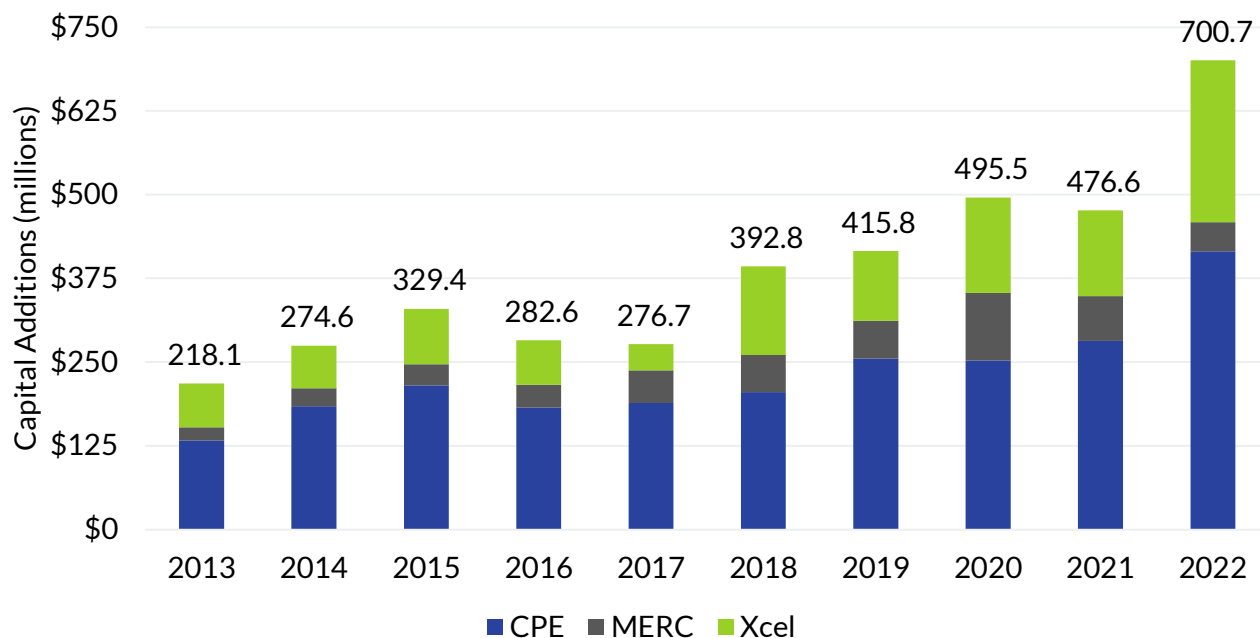
1.2 RECENT INVESTMENTS IN GAS UTILITY PLANT

The rate at which the Minnesota LDCs have made capital investments in utility plant has increased steadily over the last decade. To demonstrate this trend, data on annual additions to plant-in-service were gathered from the GJARs filed over the previous ten years.⁸ Figure 1.1 shows capital investments for Minnesota's three

⁸ Pages 13-16 of the GJARs provide beginning of year (BOY) plant-in service, annual additions (plant put into service), annual retirements (plant taken out of service early), other annual account adjustments and transfers, and end of year (EOY) plant-in service balances for each plant account by function. The cumulative additions across all accounts were used to identify the annual additions for CPE and MERC. Xcel is unique in that it only provides the BOY and EOY balances by utility function. Xcel notes this presentation is because they are a multi-service (electric and gas) and multi-jurisdiction (MN and SD) utility where much of the plant-in-service is shared. The balances, accordingly, are said to be proportional

largest gas utilities—CPE, MERC, and Xcel—since 2013. Over this period, the combined annual expenditure on capital additions by the three utilities has grown from \$218 million in 2013 to over \$700 million in 2022.

Figure 1.1: Natural Gas Utility Capital Investment in Minnesota, 2013–2022



Sources: Gas Jurisdictional Annual Reports for each utility, 2013 to 2022. See Minnesota Public Utilities Commission, “MN DOC Efilng,” available <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showeDocketsSearch&showEdocket=true>, dockets 14-04, 15-04, 16-04, 17-04, 18-04, 19-04, 20-04, 21-04, 22-04, and 23-04.

Table 1.2 shows the compound annual growth rate (CAGR) in utility plant-in-service for the three Minnesota utilities ranged from 6.9 to 9.1 percent over the last 10 years.

Table 1.2: Utility Plant-in-Service and Capital Additions by Company, 2013–2022

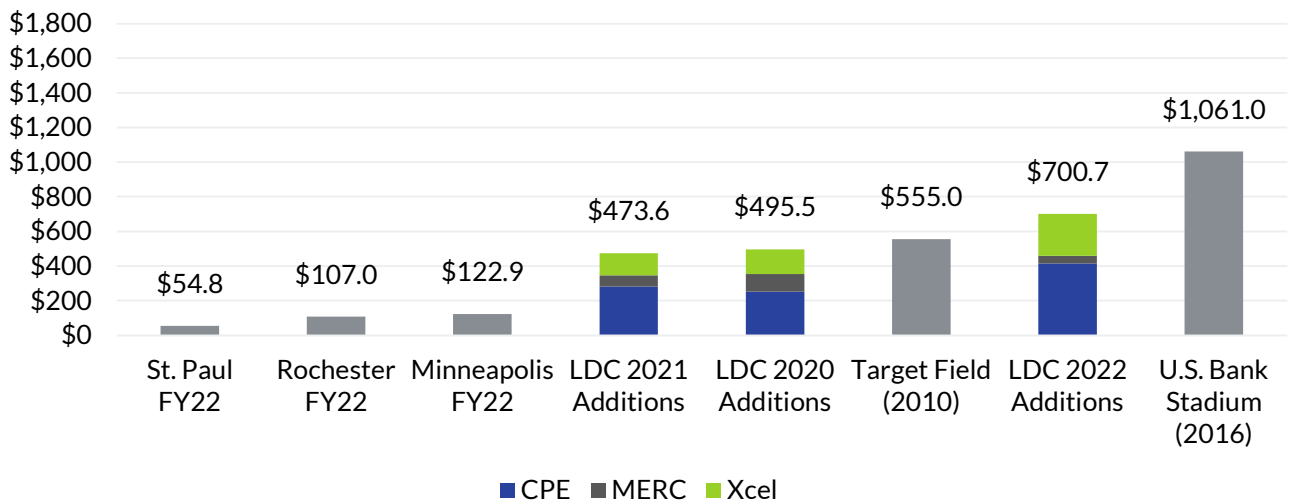
Utility	Utility Plant-in-Service (million \$)		10-year CAGR in Utility Plant-in-Service
	Start of 2013	End of 2022	
CPE	\$1,493.87	\$3,584.71	9.1%
MERC	\$358.23	\$817.06	8.6%
Xcel	\$983.26	\$1,921.31	6.9%

Source: Gas Jurisdictional Annual Reports for each utility, 2013 and 2022. See Minnesota Public Utilities Commission, “MN DOC Efilng,” available <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showeDocketsSearch&showEdocket=true>, dockets 13-04, 23-04.

allocations of plant to the Minnesota gas jurisdiction. This GJAR presentation meant that there was no identification of the exact number of capital additions made by Xcel each year in their annual reports. For this reason, Xcel’s annual capital additions in the analysis had to be estimated as the net difference between EOY and BOY plant-in-service plus one percent of the beginning of year plant-in-service. This additional one percent was included to cover the retirements in the year.

For perspective, Figure 1.2 compares the capital additions made by the three companies in 2020, 2021, and 2022 to other recent capital outlays in Minnesota. The \$700.7 million combined investment in utility plant additions for 2022 is between the \$555 million cost of Target Field when it opened in 2010 and the \$1.061 billion cost of U.S. Bank Stadium when it opened in 2016—and it represents just one year of gas utility plant additions. This \$700.7 million amount is also more than double the combined \$285 million in capital budgets approved by Minneapolis, Rochester, and St. Paul for fiscal year 2022.

Figure 1.2: Comparison of 2022 LDC Capital Additions to other Minnesota Capital Outlays (in millions)



It may seem inappropriate to compare investor-owned utility investments to entirely or partially publicly funded capital projects. However, it is important to consider that while utility plant investments by the Minnesota LDCs are initially funded through private investment, Minnesota ratepayers are ultimately responsible for paying the costs. Capital investments are recovered from utility customers over time through a depreciation charge—often for more than 30 years (and as long as 60 years) depending on the life of the asset—until fully depreciated. Each year, IOUs also earn a return on investment equal to its regulator-approved rate of return times the undepreciated portion of their capital investments.

The rapid increase in the balance of utility plant-in-service over the last decade has been caused by higher and higher levels of capital investments in utility plant.

1.3 DRIVERS OF UTILITY CAPITAL INVESTMENT

As shown above, the level of capital investments made by the three gas companies in this study has more than doubled over the last decade. Four factors that, to varying degrees, have likely contributed to this rise in capital investment expenditures are discussed below.

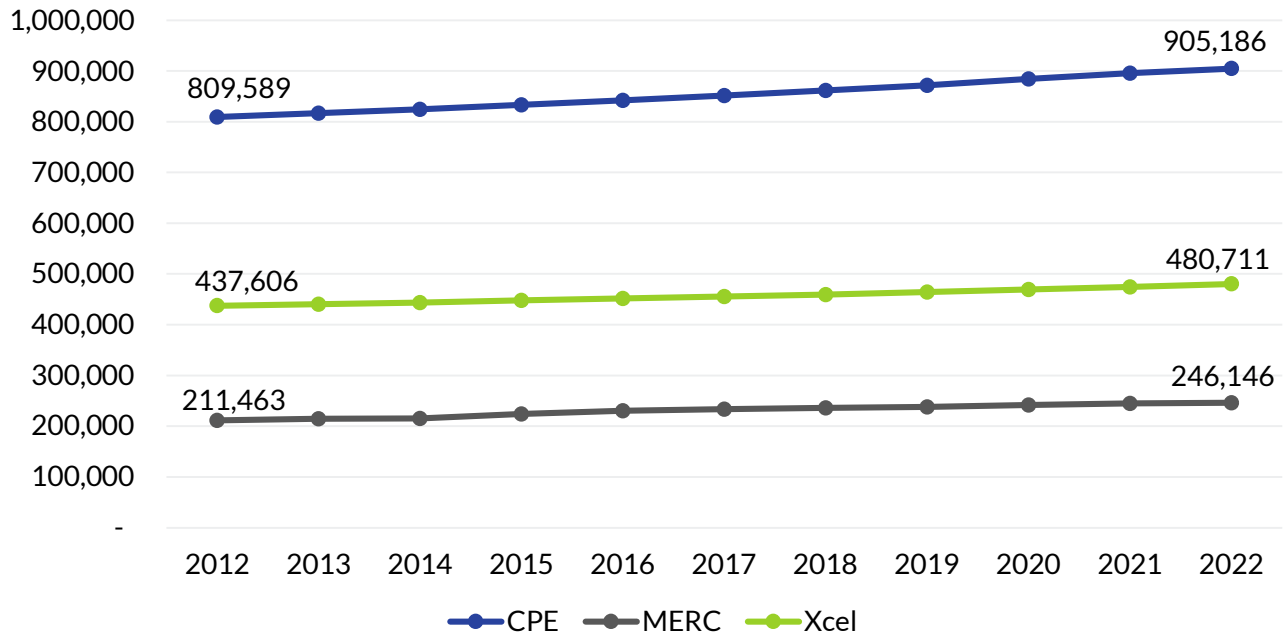
1.3.1 CUSTOMER GROWTH AND NETWORK EXPANSION

Historically, capital investments in gas infrastructure were heavily driven by capacity and network expansion needs due to customer growth. Investments in gas infrastructure are driven by both increases in customer demand and customer growth. As customer demand for natural gas increases, utilities must expand their distribution network capacity to meet that demand. Customer growth also requires expansion of the delivery

network to reach customers where gas service was not previously available. Over the past 20 years, the rate of gas network expansion has slowed, and the corresponding effect has been that the growth and expansion investment activities have become a smaller aspect of utility investment plans.

Figure 1.3 shows the number of customers of each utility from 2012 through 2022. There has only been modest growth in customers over this period: 1.12 percent CAGR for CPE, 1.53 percent CAGR for MERC, and 0.94 percent CAGR for Xcel. These CAGRs are well below the rate of change in utility plant-in-service, indicating that customer growth has not been a major driver of increased utility plant investment.

Figure 1.3: CPE, MERC, and Xcel Customers, 2012-2022



Sources: Gas Jurisdictional Annual Reports, 2013-2023. See MN DOC Efilng Dockets 13-04, 14-04, 15-04, 16-04, 17-04, 18-04, 19-04, 20-04, 21-04, 22-04, and 23-04.

1.3.2 SAFETY AND RELIABILITY

Another driving force behind a gas operator’s investment decision are investments needed to respond to safety and reliability concerns. As pipeline networks in the United States have aged, investment decisions have increasingly been made in response to concerns about the integrity of the aging infrastructure and its functional ability to operate safely and reliably. Determinations on what types of materials need to be prioritized for replacement have been guided by safety notices and requirements from federal regulators. The Pipeline and Hazardous Materials Safety Administration (PHMSA), a division of the U.S. Department of Transportation, is responsible for developing and enforcing regulations for the safe, reliable, and environmentally sound operation of the nation’s pipeline transportation system.

As part of its mandate, PHMSA issues notices, advisories, and guidance on leak-prone materials used in pipeline infrastructure to guide decisions on how investments are prioritized. PHMSA has primarily focused on urging

gas operators to address the replacement of *leak-prone gas pipeline materials*. Cast iron, unprotected steel⁹, copper, and certain types of plastic¹⁰ are examples of materials that have been identified as particularly susceptible to leaks, corrosion, and other forms of degradation.

A pivotal moment in recent gas pipeline safety was the 2010 explosion incident on a transmission pipeline in San Bruno, CA that killed eight people and leveled 38 homes. Afterward, PHMSA reevaluated its approach to safety regulation, which had relied on identifying risks through lessons from actual events to a more proactive approach where operators were required to identify and address risks unique to their systems. Among the steps taken by PHMSA was to establish the Distribution Integrity Management Program (DIMP) and Transmission Integrity Management Program (TIMP). These programs require gas distribution and transmission operators to implement comprehensive safety plans aimed at identifying and mitigating risks, improving pipeline integrity, and preventing future accidents. The DIMP and TIMP plans submitted to PHMSA have become fundamental documents used by utilities in the informational support they present to regulators to justify their safety and reliability investments.

PHMSA made its most urgent plea in 2011, a Call to Action to all industry stakeholders to accelerate the repair, rehabilitation, and replacement of the highest-risk pipeline infrastructure identified as cast iron, copper, bare steel, and certain types of welded pipe, and older steel pipe in high consequence areas.¹¹

1.3.3 REGULATION AND COST-RECOVERY MECHANISMS

As outlined in the previous section, federal regulation from PHMSA has played a critical role in guiding the types of investments that gas system operators prioritize for safety and reliability reasons. Regulators and legislators at both state and federal levels have adopted measures that accelerate the pace of infrastructure investments through a combination of enforcement mechanisms, such as regulations and standards, and incentives, such as advanced cost-recovery mechanisms.

ADVANCED COST-RECOVERY MECHANISMS

IOUs subject to rate regulation argue that the traditional rate-of-return approach to regulation limits their ability to implement large safety and reliability investment programs. Traditionally, rates are set by a regulator based on historical costs or a projected “test year” (including investments in plant-in-service) and then not reset until the next time the utility submits a new rate request. This means that investments made in between rate cases are not reflected in rates until new rates are set. This time differential between when an investment is put into service and when the utility begins to recover it in base rates is called regulatory lag.

One way that utilities try to address concern over regulatory lag is to file more frequent base rate cases. CPE is an example of a utility that has taken this approach by filing for new base rates every other year since 2013. Another regulatory approach used to address concern over regulatory lag is the adoption of capital tracker mechanisms, such as the Gas Utility Infrastructure Cost (GUIC) mechanism in Minnesota. Mechanisms like

⁹ Unprotected steel refers to steel pipelines that do not have any coatings, linings, or other forms of protection against corrosion and external damage.

¹⁰ There are some types of plastic pipe that have been identified as leak-prone by utilities and are included in their replacement programs. The most common of these is a type of plastic pipe called “Aldyl A” that was manufactured by DuPont prior to 1973. There are also some general concerns about any type of plastic pipe from the early 1980s and earlier.

¹¹ [USDOT Pipeline Safety Action Plan \(November 2011\)](#)

GUIC allow utilities to recover the costs of approved capital projects between rate cases, reducing regulatory lag.

Nationally, the slow response of utilities to replace leak-prone and aging infrastructure on their gas delivery systems was one area where regulatory lag was cited as a contributing challenge. In response to PHMSA's 2011 Call to Action, many states, either by statute or regulation, created capital tracker mechanisms, like GUIC, that permitted utilities to recover costs of certain eligible capital projects between base rate cases to promote acceleration of replacement activities. These mechanisms have indeed been successful in promoting rapid increases in expenditures on gas infrastructure nationwide. However, the increased investments have been at the expense of ratepayers who now, in many areas of the country, pay almost as much or more to have gas delivered than they do for the gas commodity itself.

NEW REGULATIONS AND STANDARDS

PHMSA and federal regulations also play a significant role in promoting accelerated levels of investments in infrastructure by establishing new safety and performance standards that necessitate compliance within specific deadlines. These regulations compel utilities to prioritize and allocate resources toward upgrading or replacing their infrastructure, ensuring that necessary improvements are made in a timely manner to meet regulatory requirements and maintain system safety and reliability.

The PIPES Act of 2020 also requires plans to address the replacement or remediation of pipelines known to leak due to their material, design, or past operating and maintenance history.

1.3.4 INTERNAL UTILITY BUSINESS GOALS

Utilities have their own internal financial and operational goals that also drive the rate of capital investment. While these objectives may lead to incremental improvements in service and operational efficiency, increased capital investments also require increases in base rates to compensate the company and its investors. Understanding how these internal business goals influence investment decisions is one of the inherent challenges for regulators when evaluating the prudence of a utility's capital investment choices.

FINANCIAL GOALS

IOUs, by their nature, are inherently beholden to their shareholders, as they must prioritize generating returns on investment and maintaining a healthy financial performance to satisfy the expectations of their investors. Capital investments increase a utility's rate base (the value of a utility's capital assets) which, in turn, generates higher revenue that could be either reinvested in capital or used to pay out higher dividends. Utilities often emphasize the importance of rate base growth when making financial presentations to investors and will set rate base growth targets to inform investors about their plans for future investment.

This relationship between capital investment and increased financial returns for the utility encourages utilities to invest in capital projects for the purpose of growing their rate base, as it allows them to increase their revenues and shareholder returns under traditional rate-of-return regulation, even if those investments may not be strictly necessary for maintaining safe and reliable operations. This is a known flaw in rate-of-return regulation known as the Averch-Johnson effect.

OPERATIONAL GOALS

Internal operational goals of utilities can also influence investment decisions. These goals involve factors that may only indirectly be related to providing basic requirements for maintaining safe and reliable operations

such as enhancing customer service, improving efficiency, and adopting innovative technologies. For example, investments in information technology and billing systems might not always have a clear connection to safety and reliability improvements. However, these investments might be made based on goals to improve overall operational efficiency or customer satisfaction.

1.4 SYSTEM PERFORMANCE AND RISK INDICATORS

Section 1.3 identified that safety and reliability concerns are major factors that drive LDC capital investment strategies. For natural gas pipeline systems, the basic undesired event is the failure of a pipeline or pipeline system that results in a release of the gas. When LDCs develop infrastructure replacement plans they often inform regulators that these activities will be prioritized around risk of an event such that pipes with higher risk will be replaced first. Risk on a pipeline is defined as a measure of potential loss in terms of both the likelihood (or frequency of occurrence) of an event and the magnitude of the consequences from the event. Likelihood is the probability or frequency of failure due to threats that affect the pipeline, and consequence is the severity of impacts to human safety, environment, or property because of a pipeline failure.¹² This is represented by the following equation:

$$\text{Risk} = \text{Likelihood} \times \text{Consequence}$$

This subsection presents different indicators used to monitor the likelihood of an event occurrence. Factors that influence the likelihood of an event on a specific piece of infrastructure are type of material, leak history, and age. Using publicly available information from PHMSA, data on each of these factors for the Minnesota LDCs will be presented to inform on the level of risk on the systems in Minnesota compared to other LDCs in the United States. Section 1.4.1 presents information on the prevalence of leak-prone materials; Section 1.4.2 addresses gas leaks and system leak rates; and Section 1.4.3 provides information on system age.

1.4.1 PREVALANCE OF LEAK-PRONE MATERIALS

Section 1.3.2 described the role PHMSA plays in providing directive to the gas transport industry on categories of infrastructure that need to be prioritized for replacement for safety and reliability reasons. Within this role PHMSA has identified certain pipe materials such as unprotected steel, cast iron, wrought iron, copper and certain vintages of plastic pipe as obsolete or leak-prone and recommended that these materials be prioritized for replacement. Because these materials have shown to be more likely to have leaks, systems with a greater prevalence of these leak-prone materials have higher risk.

PHSMA collects data on the mileage and material makeup of gas pipelines to track the progress being made on replacement of these leak-prone and obsolete materials. This data can provide insight into the levels of pipeline risk in a state or on a specific company's system. Table 1.3 shows the materials used in each utility's distribution mains in 2022; Table 1.4 shows the materials used in each utility's services.

¹² [Pipeline-Risk-Modeling-Technical-Information-Document-02-01-2020-Final.pdf \(dot.gov\)](#)

Table 1.3: Distribution Main Pipeline Materials by Utility (in Miles), 2021

Material	CPE	MERC	Xcel
Unprotected bare steel	68.29 (0.48%)	--	0.70 (0.01%)
Unprotected coated steel	4.10 (0.03%)	--	63.70 (0.66%)
Cathodically protected bare steel	23.18 (0.16%)	--	--
Cathodically protected coated steel	3,371.79 (23.49%)	1,430.33 (27.06%)	745.90 (7.76%)
Plastic	10,888.56 (75.85%)	3,856.23 (72.94%)	8,776.50 (91.32%)
Cast/Wrought iron	--	--	--
Other	--	--	23.60 (0.25%)
Reconditioned cast iron	--	--	--
Total	14,336	5,287	9,610

Source: Pipeline and Hazardous Materials Safety Administration (PHMSA), "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data," available <https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids>.

Table 1.4: Distribution Service Pipeline Materials by Utility (Number of Services), 2021

Material	CPE	MERC	Xcel
Unprotected bare steel	117 (0.01%)	--	95 (0.02%)
Unprotected coated steel	--	--	2,397 (0.53%)
Cathodically protected bare steel	--	--	--
Cathodically protected coated steel	41,272 (5.23%)	37,766 (16.08%)	5,588 (1.23%)
Plastic	740,368 (93.90%)	196,717 (83.77%)	440,763 (96.97%)
Cast/Wrought iron	--	--	--
Copper	2,982 (0.38%)	358 (0.15%)	486 (0.11%)
Other	3,702 (0.47%)	--	5,214 (1.15%)
Total	788,441	234,841	454,543

Source: PHMSA Annual Report Data.

Compared to other parts of the country, the Minnesota LDCs have much lower levels of unprotected steel, cast iron, and copper pipes for which PHMSA has called for priority replacement. Figure 1.4 shows the percentage of mains and services that are leak-prone for the three companies compared to different regions and the United States overall.

Figure 1.4: Composition of Leak-Prone* Mains (Left) and Services (Right) by Utility and Region, 2022



Source: Pipeline and Hazardous Materials Safety Administration (PHMSA), “Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data,” available <https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids>.

*Leak-prone materials include unprotected bare steel, unprotected coated steel, cathodically protected coated steel, cast iron, wrought iron, and copper.

The leak-prone figures above do not include certain types of plastic mains or services that may also be considered leak-prone. PHMSA has found that some types of plastic pipes are prone to cracking and failure, such as certain vintages of “Aldyl-A” plastic pipes manufactured by Dupont that were used before the current industry standards were fully developed. The challenge for analyzing these categories of pipe is that PHMSA data does not currently distinguish pipes by type of plastic in the annual reports, because record-keeping practices for tracking pipe manufacturers were not well established when these pipes were originally installed. This means equivalent information on leak-prone or obsolete plastic pipes is not readily available.

The Minnesota LDCs each have noted in regulatory filings to the PUC that there is Aldyl-A pipe on their systems. CPE had approximately 400 miles as of 2019 (about 2.8 percent of their total pipeline mileage)¹³ and MERC had 374 miles as of 2021 (about 7.1 percent of their total pipeline mileage).¹⁴ Xcel has identified through GUIC and other filings that Aldyl-A pipe is present on its system but no count on the specific population could be found in their regulatory filings. CPE, MERC, and Xcel may contend that because they have these quantities of Aldyl-A plastic pipe on their systems that the implication that there are low levels of leak-prone materials on their systems is incorrect.

It is important to recognize, however, that the historical directives from PHMSA on these plastic pipes have been different from those on cast iron, wrought iron, and bare steel. First, Aldyl-A refers to several vintages of plastic pipes that were made by Dupont from the 1960s through the 1990s. It is the pipes manufactured from 1970 to 1972 that were found to be materially defective and then only 30 to 40 percent of the pipes over this period are believed to have the defect.¹⁵ Because this is a small subset of an overall larger category, PHMSA’s notices on Aldyl-A pipe have accordingly asked operators to focus on monitoring the performance of pre-1973

¹³ Direct testimony of Mr. William A. Kuchar III, P.E. as part of CPE’s Initial filing in Docket 19-524 (201910-156946-02) at page 58.

¹⁴ Cover Letter to MERC’s Initial filing in Docket 22-127 (2206-186692-2) at page 45.

¹⁵ See the California Public Utility Commission’s “[Hazard Analysis & Mitigation Report On Aldyl A Polyethylene Gas Pipelines](#)” for an extensive overview of the history of Aldyl-A pipe in California.

Aldyl-A plastic pipe. Replacement is recommended when there is evidence the pipe is experiencing increasing rates of leaks or there are records establishing the pipe has a defect. PHMSA’s 2021 advisory bulletin, following the 2020 PIPES Act, also emphasizes that only certain “historic plastics with known issues” should be prioritized for replacement.¹⁶

The point for consideration here is that while LDCs may have Aldyl-A pipe on their systems, these pipes should not be immediately understood to represent the same level of risk as iron and bare steel pipes. The recommendation action for this class of pipe is to monitor performance and prioritize replacement of only those vintages that have shown increased rates of failure. Leak rates and leaks, discussed in the next section, are examples of data that can be used to track performance of a system or class of pipes over time.

1.4.2 LEAKS AND LEAK RATES

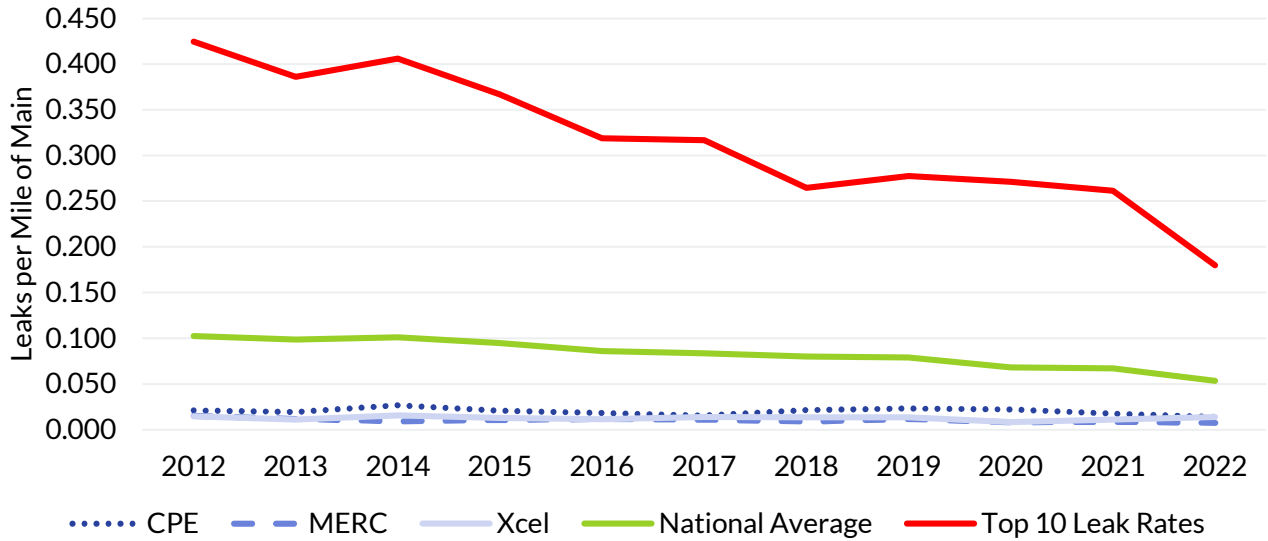
Monitoring the number and rate of leaks over time can provide valuable insights into the overall health of a gas distribution system. For instance, an increase in the number or rate of leaks may indicate deteriorating infrastructure that requires maintenance or replacement. Rapid increases in the number of leaks or prolonged periods of increasing leak rates may indicate that a specific class/material of pipes might be failing faster than others.

The leaks reported to PHMSA are only the leaks that have been detected and identified by pipeline operators or other observers. These are considered “known” leaks. Undetected or unidentified leaks, sometimes referred to as “unknown” leaks, are not included in these reports because, by definition, operators are unaware of them. Appendix A contains definitions for the leak causes that PHMSA requires operators to use when tracking main and service leaks as they are identified and repaired.

Figure 1.5 shows the number of leaks per mile of distribution main, and Figure 1.6 shows the number of leaks per hundred services for each company (excluding excavation-related leaks, which are caused by human error and not necessarily indicative of the condition of the pipelines). These indicators show that both main and service leaks on the three systems have been relatively stable over the last decade. For comparative purpose, the national averages and weighted average of the utilities with the ten-highest leak rates are also provided.

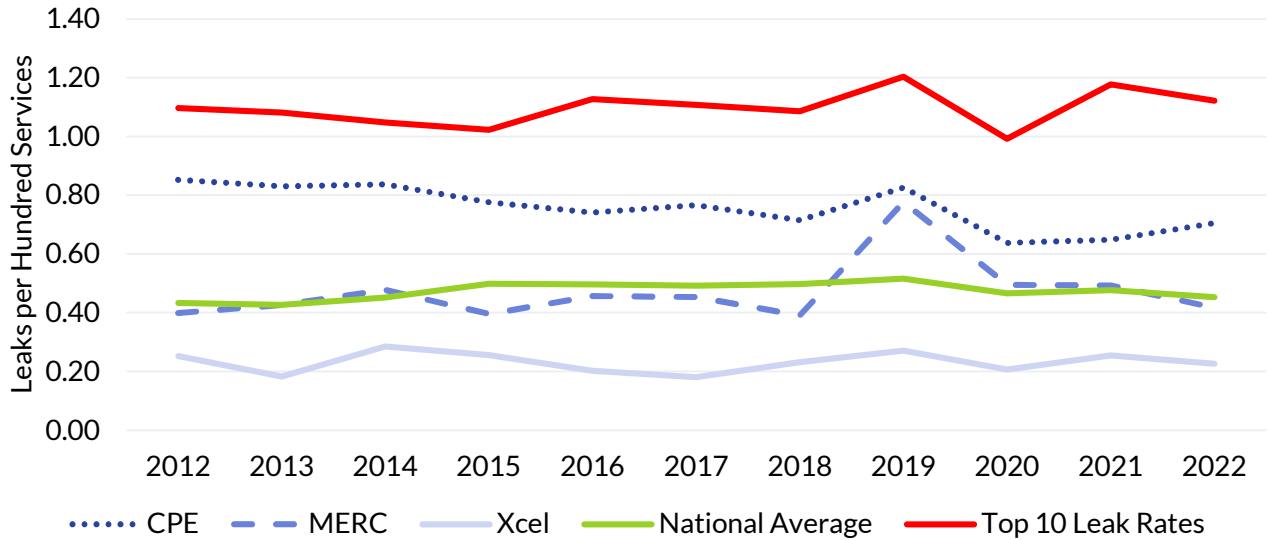
¹⁶ PHMSA Advisory Bulletin: Pipeline Industry Must Take Actions to Address Methane Leaks from Pipelines and Pipeline Facilities (June 2021) [Draft 2.Clean\(dot.gov\)](#)

Figure 1.5: Leaks per Mile of Main, 2012-2022



Source: PHMSA Annual Report Data.

Figure 1.6: Leaks per Hundred Services, 2012-2022



Source: PHMSA Annual Report Data.

While the service leak rates are relatively stable across each of the Minnesota LDCs, the leak rate levels on services are around or above the national averages. CPE's service leak rates have been above the national incidence levels for over ten years. This indicates that CPE is dealing with a persistent issue or problem with a specific component or pipe material. Looking at the cause of the leaks reported by each operator can provide further detail on why and where these leaks are occurring. Table 1.5 shows how the composition of non-excavation service leaks in 2022 at CPE, MERC, and Xcel compares to the composition of non-excavation service leaks experienced nationally.

Table 1.5: Composition of Non-Excavation Service Leaks by Cause, 2022

Cause	National	CPE	MERC	Xcel
Non-Pipe Equip. Failure	52.5%	84.6%	51.1%	56.8%
Corrosion	17.1%	6.6%	1.2%	3.0%
Pipe/Weld/Joint	10.1%	1.6%	22.3%	8.9%
Other	6.9%	0.7%	9.2%	21.9%
Other Outside Force	4.7%	2.3%	5.1%	6.0%
Natural Force	4.6%	1.5%	6.4%	3.3%
Operator Error	4.2%	2.5%	4.7%	0.2%

Source: PHMSA Annual Report data.

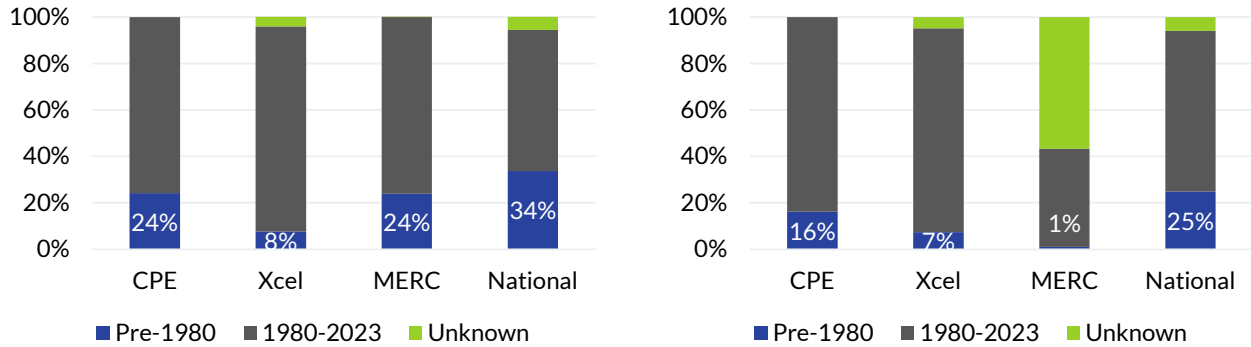
Notable for CPE is that its relatively higher rate of service leaks experienced recently appears to be driven by non-pipe equipment failures that are well above the national average. This result implies that the issue is not with a specific pipe material, but with another service-related component. For MERC, it is notable that service leaks from a pipe, weld, or joint failure are occurring at a greater frequency on its system than they occur nationally. This cause (along with corrosion) is more indicative that a specific class/material of pipe is failing. While Xcel's service leaks are mostly of note due to leak rates that are well below the national average, it is also of interest that almost a quarter of leaks cannot be categorized under any one of the standard PHMSA leak causes. This result implies that there are unique issues that Xcel is addressing that do not fall under the standard leak causes.

1.4.3 AGE/VINTAGE

Understanding the age of the pipeline infrastructure on a distribution system is another piece of information that can inform us on the level of risk on a distribution system. PHMSA has also advised operators to focus on replacement of older pipelines based on the premise that improvements in pipe manufacturing, design, construction, and maintenance practices have improved over time, making older pipes higher risk than newer pipes. In practice, because most of the oldest pipes on gas systems have been cast iron, bare steel, and wrought iron, the attention to specific materials has overlapped with the recommendation to focus on older vintage pipelines.

The PHMSA pipeline reports that LDCs file annually identify the miles of main and services by decade installed. Using this data, the figures below show how the percentage of mains and services installed on the three Minnesota systems compares to the age of all national pipelines. Figure 1.7 shows what proportion of mains (left) and services (right) were installed prior to 1980 (i.e., are at least 44 years old). Some companies, such as MERC, have a significant number of assets with unknown age (green bars) because they do not have sufficient records to establish the exact age.

Figure 1.7: Vintage of Mains (Left) and Services (Right)



Source: PHMSA Annual Report data.

Like the indicators presented on leak-prone materials and incidence of leaks, these age indicators also show that the systems in Minnesota have lower risk compared to national averages.

1.5 APPROACH AND OUTLINE OF STUDY

Section 1.1 introduced the concept of utility plant-in-service and identified the different categories of assets that LDCs make capital investments in every year. Section 1.2 demonstrated that the total annual capital additions made by CPE, MERC, and Xcel in Minnesota has grown from \$218 million to \$700 million over the last ten years. As discussed in Section 1.3, there are various reasons why the rate of investment has increased. The speed at which investments are being made has had corresponding impacts on the base rates that LDCs charge to customers to recover the costs of their capital investments. Furthermore, as evident by the jump in spending in 2022, the capital spending by Minnesota’s three largest utilities does not show signs of slowing down. This study attempts to understand what the potential impact on residential base rates will be if the Minnesota LDCs continue to make capital investments at historically high rates, as they intend to do.

Section 1.5.1 explains the methodology and approach used to develop the base rate projections, Section 1.5.2 identifies the resources used to develop the assumptions used in the analysis, and Section 1.5.3 describes how the rest of the paper is organized.

1.5.1 METHODOLOGY

Monthly customer bills for natural gas services are divided into two components: (1) the commodity portion that reflects the costs of the gas that customers consume; and (2) the "base" or delivery portion that accounts for the capital and operating expenses incurred by LDCs to provide gas delivery services. The primary output of this study is a set of projections for what base rates could be from 2024 to 2040 if the Minnesota LDCs make capital additions at the rates planned by each company.

There were three analytical steps taken to produce these outputs:

- **Step 1: Develop capital investment and rate base projections.** In the utility rate setting process, the current value of a utility company's capital assets (which includes the undepreciated portion of utility plant-in-service among other assets) is referred to as *rate base*. As investments are made in utility plant-in-service, the growth in rate base requires a corresponding increase in base rates to provide investors a return of their investment (in the form of depreciation) and a return on investment (rate base multiplied by the company's weighed cost of capital). The first step in the study was to develop a set of assumptions on what the future capital expenditures will be for each company that are then used to determine the rate base for each year of the forecast period. These assumptions were developed based on investment plans each company has shared with its investors.
- **Step 2: Estimate the annual revenue requirements.** The amount of revenue a utility company needs to collect from its customers through base rates to cover its costs of providing service and earn a rate of return for its investors is called the *revenue requirement*. Revenue requirements include capital-related costs (depreciation, return on rate base, and property taxes) and operating-related costs (operation and maintenance expenses) components. For this study, the capital portion of the revenue requirement was developed from the capital investment and rate base projections in the first step. The assumptions for operating expenses were taken from base rate proceedings and/or annual reports from the companies and grown at the rate of inflation.
- **Step 3: Calculate base rates and present typical customer bills.** A portion of the revenue requirement was assigned to the residential classes of each LDC based on the apportionment of the revenue requirement used in each company's most recent base rate proceeding. Then, base rates were calculated using the same billing determinants (customer-months and therm sales) also used in the most recent proceeding for each company. Note that the number of customers and annual sales are kept constant for the entire forecast period. This was done for practical reasons. Given the questions about the role of gas in Minnesota's energy future, which will be touched on in Section 4, there are a multitude of paths that the number of residential customers and annual sales could take over the next 20 years. To maintain the focus of the study on the interaction between capital investments and base rates, the number of customers and annual sales have been kept constant.

Section 2 and Section 3 go into greater detail on the approach taken for each step and provide the results by company.

1.5.2 ASSUMPTIONS AND SOURCE MATERIAL

The assumptions used in the analysis were developed around publicly available information from the companies, including each of the following sources of data:

- **Gas Jurisdictional Annual Reports (GJARs):** These are annual financial reports filed by each utility with the Minnesota Department of Commerce by April of each year. The advantage of using these reports is that they are produced regularly and are standardized to report the same information for each utility. The disadvantage of these reports is that some of the contents may have to be estimated, especially for utilities that operate in multiple jurisdictions. We used GJARs to determine historical rates of capital additions and retirements and to develop assumptions about operating expenditures to be included in the revenue requirement.

- **Investment plans submitted as part of regulatory filings:** Regulatory filings, such as general rate cases or GUIC rider filings, include amounts of planned capital investments. The advantage of these is that they make clear how investments contribute to final rates; the disadvantage is that these regulatory proceedings are lengthy, so it may take a while to learn which investments are approved by the Commission to be included in rate base or recovered through the GUIC rider. We used regulatory filings to develop assumptions about capital expenditures to be included in the revenue requirement, to develop rate design and bill determinant assumptions, and to determine actual historical delivery charges.
- **Presentations made to shareholders:** These are quarterly or annual presentations made to company shareholders that, among other things, update shareholders on financial results and future investment plans. The advantage of these is that they often provide the company's investment goals over the medium term. However, because shareholder presentations are prepared for utilities' parent companies, they do not provide much detail at the individual utility level. We used these presentations as the basis of assumptions about future rate base growth.

1.5.3 ORGANIZATION OF THE STUDY

The remainder of this paper provides the results of the study and addresses how these results fit into the current policy and regulatory context in Minnesota. First, Section 2 (Capital Additions and Rate Base Projections) includes an overview of the approach and assumptions used to forecast future capital additions and presents the results. Next, in Section 3 (Revenue Requirement Projections and Rate Impacts), the corresponding revenue requirements needed to pay for the projected investments are described. A pathway of the residential base rates needed to recover these revenues requirements is developed out to 2040 and is used to estimate the bill impacts on a typical customer. Then, Section 4 (The Future of Natural Gas in Minnesota) discusses how this analysis relates to the intersecting issues of Minnesota's clean energy goals and social inequities in the rate setting process. Finally, in Section 5, the paper concludes with a summary of the findings and key takeaways from this study.

SECTION 2 CAPITAL ADDITIONS AND RATE BASE PROJECTIONS

This study aimed to identify the future path for base rates if the Minnesota LDCs continue to invest at their planned rates. To this end, the first step in the analysis was to identify assumptions for what represents this base case investment scenario. This section describes the approach we used to develop assumptions for the capital investments that CPE, MERC, and Xcel will make through 2040.

We considered three capital investment scenarios to use:

- **Inflation Only:** The level of additions shown in each company's most recent GJAR (FY 2022) was assumed to grow at the rate of inflation throughout the forecast period.
- **Compound Growth:** IOUs will periodically identify forecasts or goals for growth in rate base in presentations made to company investors. Recent annual rate base growth targets were identified for the three utilities in this study: CPE's shareholder presentation forecast 10.95 percent annual growth in rate base through 2026;¹⁷ MERC's presentation forecast 7.4 percent annual growth through 2027;¹⁸ and Xcel's presentation projected 6.0 percent annual growth through 2026, followed by 6.5 percent annual growth through 2031.¹⁹ For the compound growth scenario, the level of investments made each year is set at the amount needed for each company to achieve these growth rate targets. For the years after a target was available, the final target year's growth rate was used through 2040. This is called a compound scenario because as investments are made to grow rate base, the amount of investment needed to maintain the same growth rate increases every year.
- **Hybrid Scenario.** The hybrid scenario uses a combination of the compound growth rate and inflation approach. For 2023 to 2031, the level of additions needed to achieve the rate base growth targets described in presentations made to shareholders are used. Because the companies provide forecasts for different time periods, CPE's and MERC's forecasts were extended through 2031 to match Xcel for the sake of consistency. For 2032 through 2040, the 2031 level of capital additions were assumed to grow at the rate of inflation.²⁰

After considering all three scenarios, the hybrid scenario was ultimately selected because it both relies on the companies' stated intentions in communications to shareholders and conservatively assumes that investments after 2031 only increase at the rate of inflation.

The following subsections describe the capital investment findings for CPE (Section 2.1), MERC (Section 2.2), and Xcel (Section 2.3).

¹⁷ CenterPoint Energy, "Establish a Path Towards Premium through Sustainable Growth: Third Quarter 2022 Investor Update," November 1, 2022, available <https://investors.centerpointenergy.com/static-files/f889e263-22dc-4531-bed8-11d34defb3d6>.

¹⁸ WEC Energy Group, "Our 'ESG' Progress Plan Update: Investing in Efficiency, Sustainability, and Growth," January 2023, available https://s22.q4cdn.com/994559668/files/doc_presentations/2023/01/01-2023-January.pdf.

¹⁹ Xcel Energy, "Essential: Investor Meetings, August 8-11, 2022," August 2022, available https://s25.q4cdn.com/680186029/files/doc_presentations/2022/08/Current-IR-Presentation-August-2022.pdf.

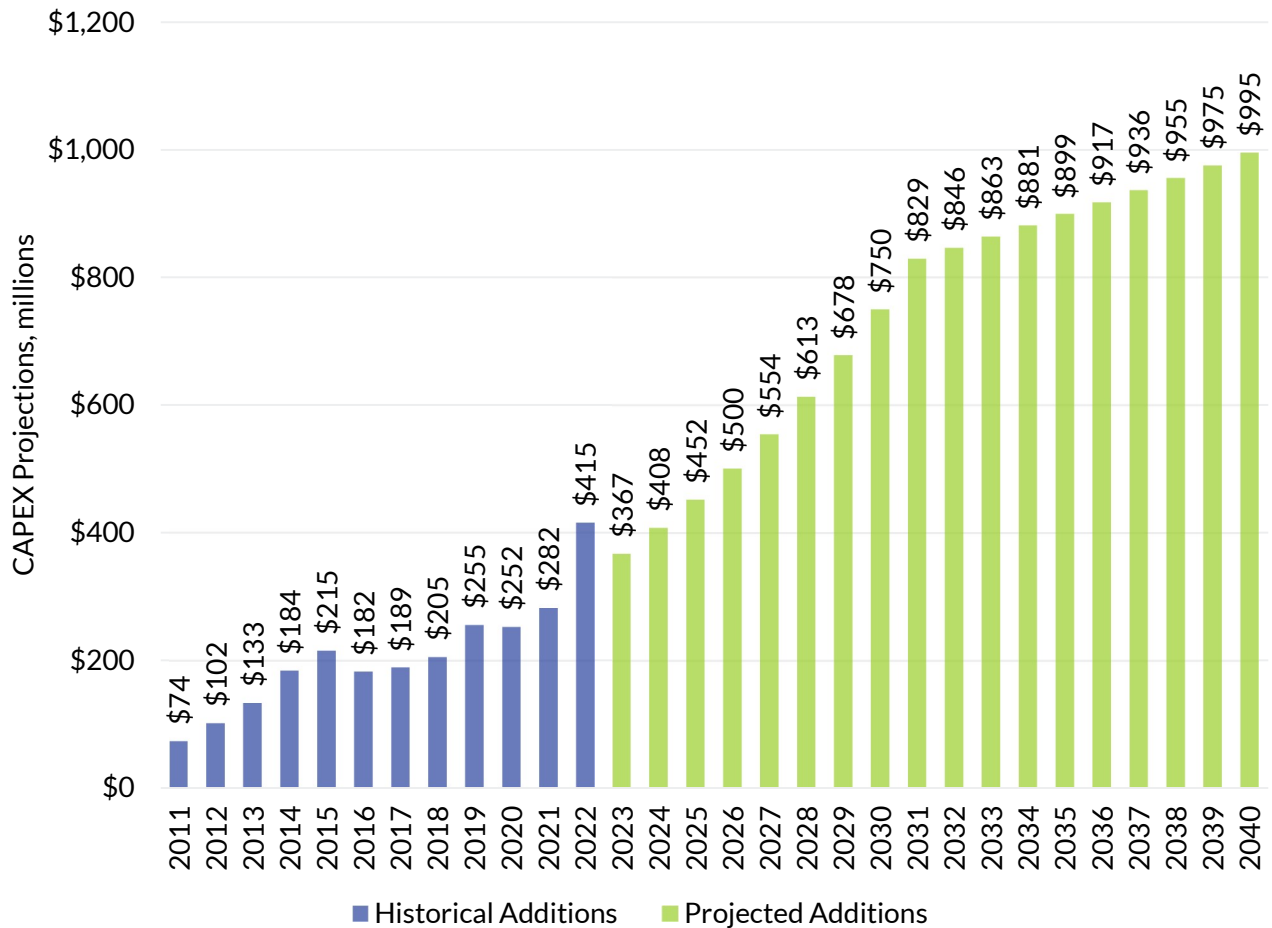
²⁰ Inflation rate forecasts are from the International Monetary Fund. The forecast goes through 2027; the inflation rate was kept constant at the 2027 rate thereafter. International Monetary Fund, "World Economic Outlook Database," available <https://www.imf.org/en/Publications/WEO/weo-database/2022/October/weo-report?c=111.&s=PCPIPCH.&sy=2020&ey=2027&ssm=0&scsm=1&ssc=0&ssd=1&ssc=0&sic=0&sort=country&ds=.&br=1>.

2.1 CENTERPOINT ENERGY

Figure 2.1 shows CPE’s historical capital additions since 2011. Capital additions have increased every year except 2016 and 2020; over the entire period, capital additions have increased from \$74 million in 2011 to \$415 million in 2022.

The figure also shows projected capital additions through 2040, based on the hybrid scenario described above. Under the hybrid model, rate base grows at the targeted rate through 2031 and at the rate of inflation thereafter. Capital additions are projected to increase from \$367 million in 2023 to \$995 million in 2040.

Figure 2.1: CPE Historical and Projected Capital Additions



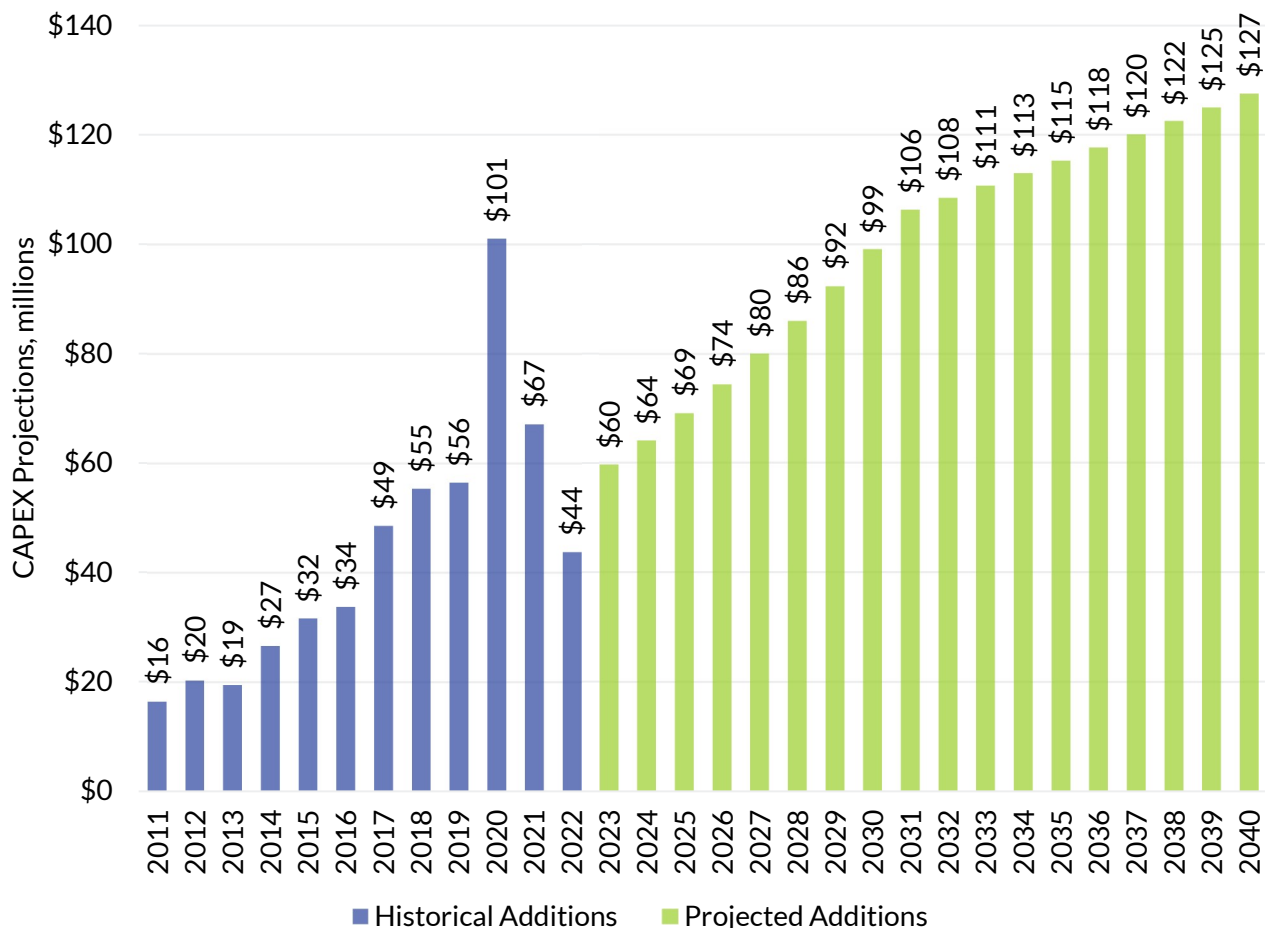
Source: 2011–2021 GJARs. See MN DOC Efilng Dockets 12-04, 13-04, 14-04, 15-04, 16-04, 17-04, 18-04, 19-04, 20-04, 21-04, 22-04, and 23-04.

2.2 MINNESOTA ENERGY RESOURCES

Figure 2.2 shows MERC’s historical capital additions since 2011. Capital additions have increased from \$13 million in 2013 to \$44 million in 2022, although several previous years were even higher than 2022.

The figure also shows projected capital additions through 2040, based on the hybrid scenario described above. Capital additions are projected to increase from \$60 million in 2023 to \$127 million in 2040.

Figure 2.2: MERC Historical and Projected Capital Additions



Source: 2011–2021 GJARs. See MN DOC Efilng Dockets 12-04, 13-04, 14-04, 15-04, 16-04, 17-04, 18-04, 19-04, 20-04, 21-04, 22-04, and 23-04.

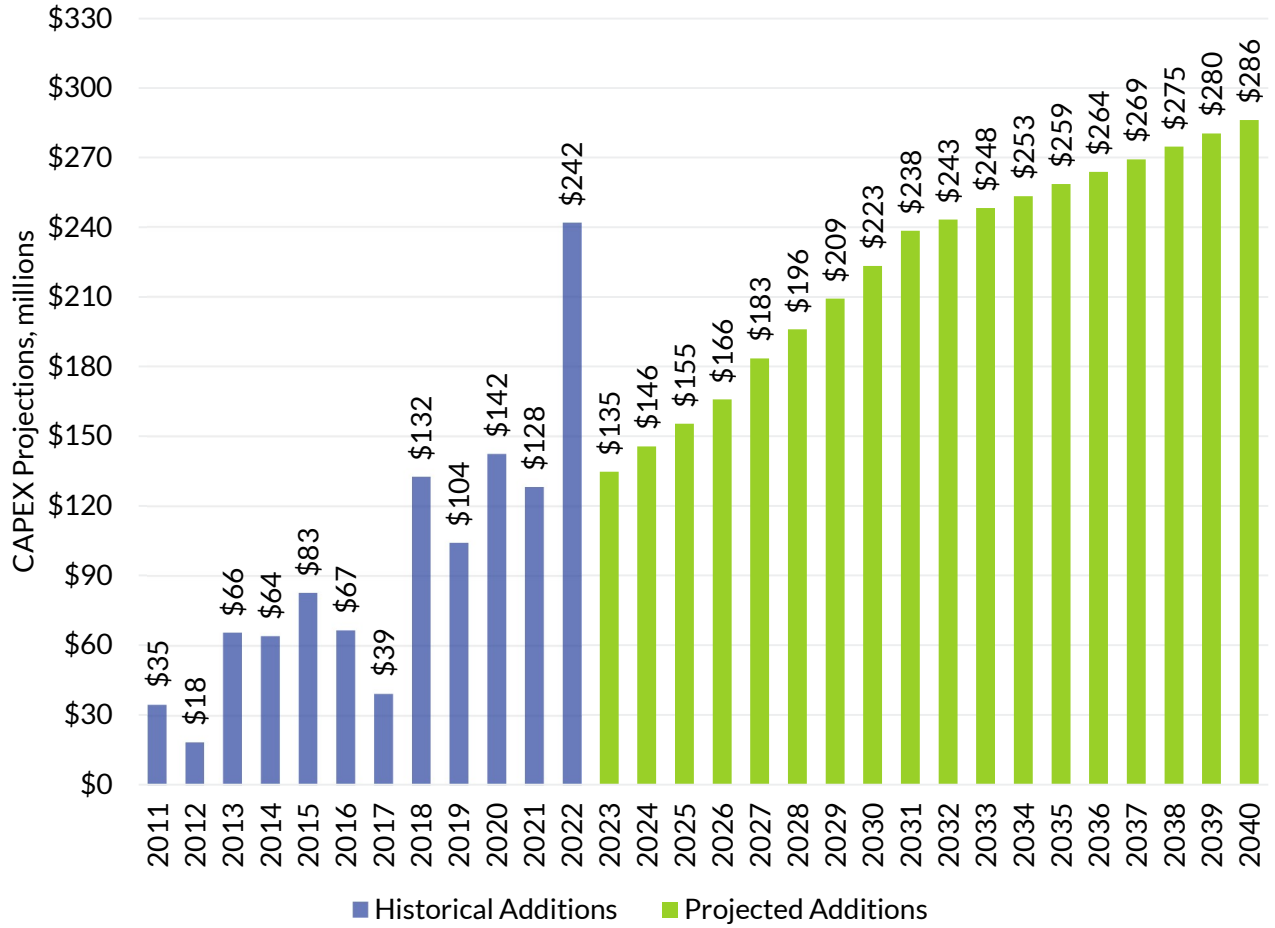
2.3 XCEL ENERGY

Figure 2.3 shows Xcel’s historical capital additions since 2011.²¹ Capital additions over the entire period have increased from \$37 million in 2013 to \$242 million in 2022.

The figure also shows projected capital additions through 2040, based on the hybrid scenario described above. Capital additions are projected to increase from \$135 million in 2023 to \$286 million in 2040.

²¹ Because Xcel Energy is a multi-utility company operating across multiple jurisdictions, it does not provide specific details on plant-in-service in its Gas Jurisdictional Annual Reports. Instead, it reports the beginning- and end-of-year balances for each asset category only. These balances “are the result of allocations and direct assignments to the Minnesota jurisdiction through the cost-of-service study.” See, for example, worksheet “16A-PLANT IN SERVICE” in Xcel’s 2021 GJAR (Docket 22-04, document ID 20224-185395-03). Additions were therefore calculated as the difference between beginning- and end-of-year balances, assuming a one percent plant retirement rate.

Figure 2.3: Xcel Historical and Projected Capital Additions



Source: 2011-2021 GJARs. See MN DOC Efilng Dockets 12-04, 13-04, 14-04, 15-04, 16-04, 17-04, 18-04, 19-04, 20-04, 21-04, 22-04, and 23-04.

SECTION 3 REVENUE REQUIREMENT PROJECTIONS AND RATE IMPACTS

After the assumptions on capital additions were developed, the next step in the analysis was to project the revenue requirements needed to recover the cost of the investments. This section presents these estimates for the revenue requirements related to the capital investment projections based on the hybrid capital growth scenario described in Section 2.

A revenue requirement model was developed to estimate capital-related components of the annual revenue requirement. The revenue requirement for the capital investment components included return on rate base, depreciation, and property taxes. To calculate the annual revenue requirement, we developed assumptions based on a mix of GJARs, general rate case filings, and GUIC filings. Table 3.1 shows the assumptions used to calculate the capital-related revenue requirements for each company.

Table 3.1: CAPEX Revenue Requirement Assumptions

	CPE	MERC	Xcel
Depreciation rate (weighted average)	3.32%	2.90%	2.976%
Retirement rate	1.27%	0.98%	1.00%
Weighted average cost of capital	6.65%	6.70%	6.97%
Effective property tax rate	2.42%	2.14%	1.91%

Sources: Retirement rates for CPE and MERC are based on the average retirement rate in 2017 to 2021 GJARs; see MN DOC Efiling Dockets 18-04, 19-04, 20-04, 21-04, 22-04, and 23-04. Xcel's GJARs do not report retirements; the retirement rate was assumed to be 1%. All other assumptions above are from MN DOC Efiling Dockets: 21-678 and 22-04 for CPE; 22-127, 22-261, and 22-504 for MERC, and 19-723 and 21-678 for Xcel.

We also developed assumptions for the level of operating costs to be included in the annual revenue requirement. Operating costs were based on other operating expenses and taxes included in recent regulatory filings and adjusted for inflation. Table 3.2 shows the starting assumptions for these values for each company.

Table 3.2: OPEX Revenue Requirement Assumptions

	CPE	MERC	Xcel
Other operating expenses	\$215.72 million	\$44.57 million	\$103.19 million
Other taxes	\$9.20 million	\$1.71 million	\$2.66 million

Sources: 2022 GJARs; see MN DOC Efiling Docket 23-04.

After the revenue requirement is established, the next step in the rate setting process is to allocate the revenue among the different rate classes served by the utility. Once the revenue to collect from each customer class is determined, base rates are designed to collect that level of revenue. In this section, we describe how the final two steps were carried out and present estimates of the resulting customer bills.

Our assumptions for residential class cost allocation factors and other billing determinants are based on recent general rate case filings for each company and are presented in Table 3.3.

Table 3.3: Rate Design and Bill Determinant Assumptions

	CPE (Docket 21-435)	MERC (Docket 22-504)	Xcel (Docket 21-678)
Residential revenue allocation %	63.00%	62.50%	64.14%
Residential customer-months	10,005,871	2,677,441	5,333,095
Sales (therms)	741,878,390	184,132,213	390,483,347
Starting fixed charge	\$9.50	\$9.50	\$9.00

We allocate the revenue requirement to the residential class using the allocation factor and then design rates (using the bill determinants) to recover this revenue target. We have kept the fixed charge the same for each company throughout the forecast period; all additional costs are added to the volumetric rate.

Gas bills include other surcharges, such as the GUIC, Conservation Improvement Program (CIP), and Gas Affordability Program (GAP) riders, which allow utilities to reconcile or recover some costs incurred between base rate adjustments. We assume that all GUIC and CIP costs are recovered in base rates (i.e., these surcharges are set to zero during the forecast period). We also assume that affordability surcharges remain at their current levels through 2040. Finally, we assume the February 2021 weather event surcharge continues at approved levels until it is scheduled to expire.

We follow this approach to estimate volumetric charges for residential customers from 2024 to 2040 and estimate monthly base rate bills based on average monthly consumption by each company’s residential customers. The subsections below present the base rate impacts for residential customers of CPE (Section 3.1), MERC (Section 3.2), and Xcel (Section 3.3).

3.1 CENTERPOINT ENERGY

Figure 3.1 shows the projected revenue requirements for CPE between 2024 and 2040. The revenue requirement triples from \$669 million in 2024 to more than \$1.9 billion in 2040.

Figure 3.1: CPE Revenue Requirements, 2024-2040



Source: Consultant projections.

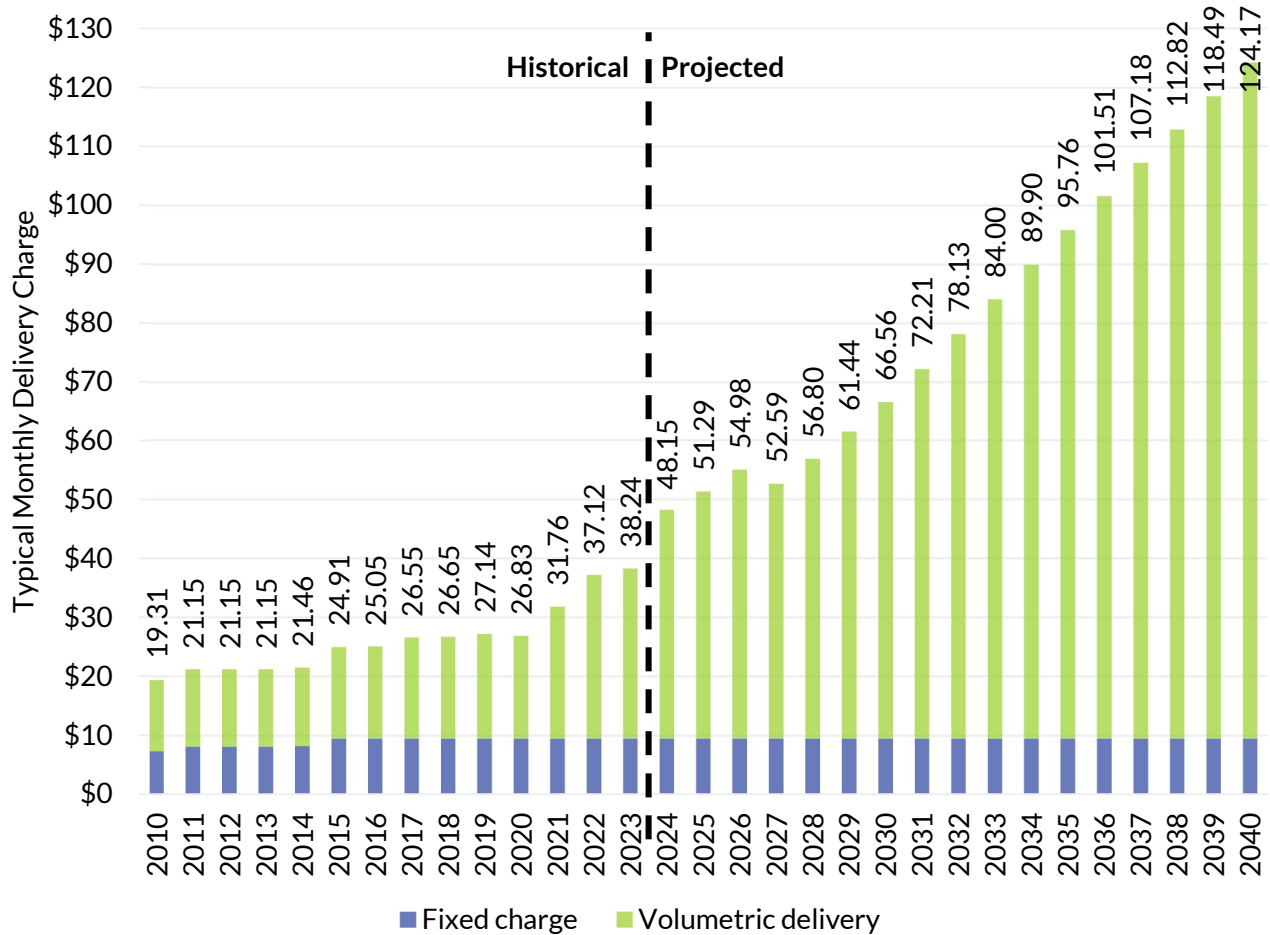
Before calculating the typical bill, we needed to calculate the base volumetric charge (i.e., the base delivery charge) using the revenue requirement projections and the allocation factor and bill determinants from Table 3.3. Table 3.4 shows how the volumetric charge for CPE was calculated for 2024; the same process was followed for each year through 2040.

Table 3.4: CPE Projected Volumetric Rate Calculation, 2024

#	Item	Note	2024
1	Revenue Requirement		\$668,482,472
2	Residential Allocation Factor		63.00%
3	Residential Revenue Requirement Allocation	Line 1 x Line 2	\$421,143,957
4	Monthly Fixed Charge		\$9.50
5	Residential Bills		10,005,871
6	Fixed Revenues	Line 4 x Line 5	\$95,055,775
7	Volumetric Revenue	Line 3 - Line 6	\$326,088,183
8	Residential Therms		741,878,390
9	Base Volumetric Charge	Line 7 / Line 8	\$0.4395

Figure 3.2 shows the historical (since 2010) and projected (through 2040) typical monthly delivery charges for CPE’s residential customers (i.e., the fixed monthly charge and the base volumetric delivery charge), based on the average monthly residential natural gas consumption for CPE’s customers (74 therms).²² Monthly delivery charges doubled between 2010 and 2023 and are projected to double again (compared to 2023) by 2032 and triple by 2039. The monthly delivery charge in 2040 is projected to be more than 6.4 times higher than it was in 2010.

Figure 3.2: CPE Typical Residential Monthly Delivery Charges, 2010–2040



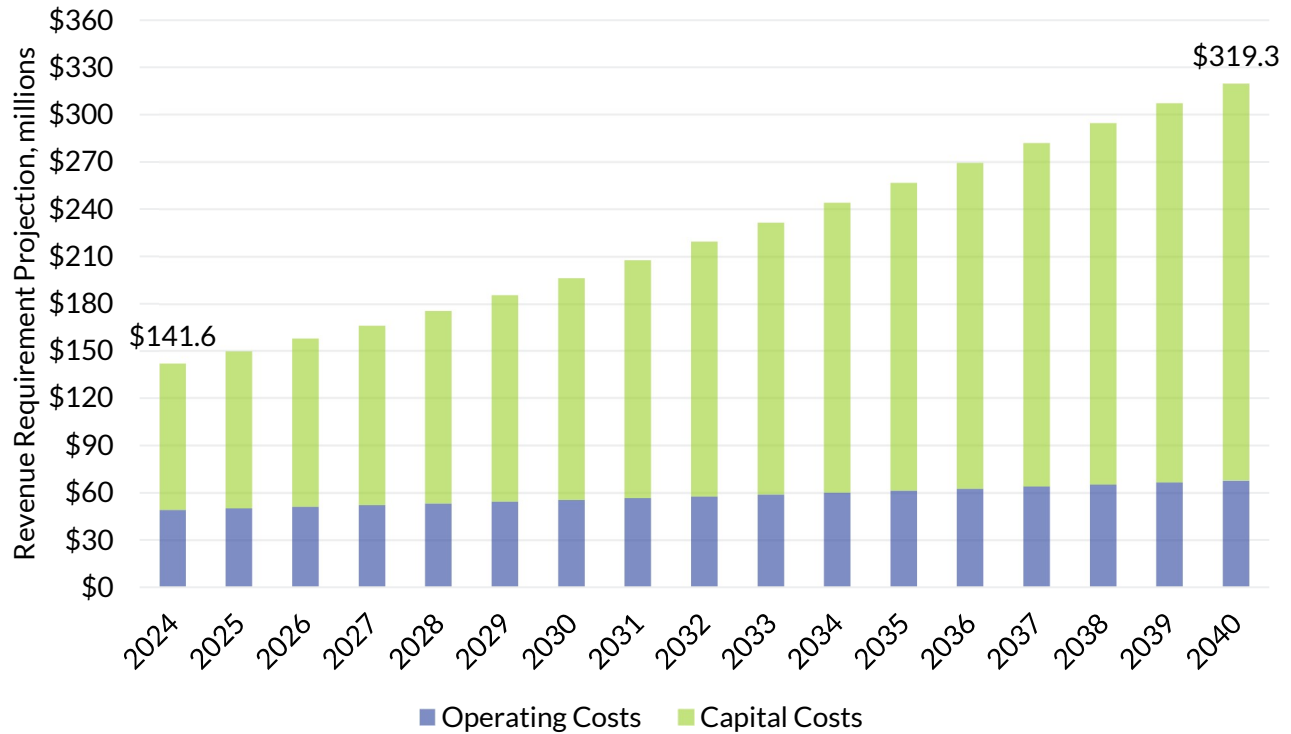
Sources: Historical delivery charges from MN DOC Efiling Dockets 08-1075, 13-316, 15-424, 17-285, 19-524, and 21-435. Projected delivery charges are consultant projections.

²² Historical rates shown are based on final rates (ignoring any interim rates) approved by the PUC and include the monthly customer charge, base delivery rate, and all riders. Weighted averages are used whenever any rate or rider changes within a calendar year. Projected rates use our projected base volumetric rates (as calculated for each year as shown in Table 3.4), keep the monthly customer charge and the GAP rider constant from their latest approved final value, assume GUIC and CIP riders are set to zero (with their costs recovered in base rates instead), and use approved schedules for the February 2021 Weather Event Surcharge until its expiry (using weighted averages whenever the surcharge value changes within a calendar year). All rates assume an average monthly residential natural gas consumption of 74 therms for CPE (see compliance filing document 202112-181109-01 at page 19 in Docket 21-435), 72 therms for MERC (see compliance filing document 20231-191989-01 at page 233 in Docket 22-504), and 73 therms for Xcel (see compliance filing document 202112-181120-01 at page 40 in Docket 21-678).

3.2 MINNESOTA ENERGY RESOURCES

Figure 3.3 shows the projected revenue requirements for MERC between 2024 and 2040. The revenue requirement increases from about \$142 million in 2024 to \$319 million in 2040.

Figure 3.3: MERC Revenue Requirements, 2024–2040



Source: Consultant projections.

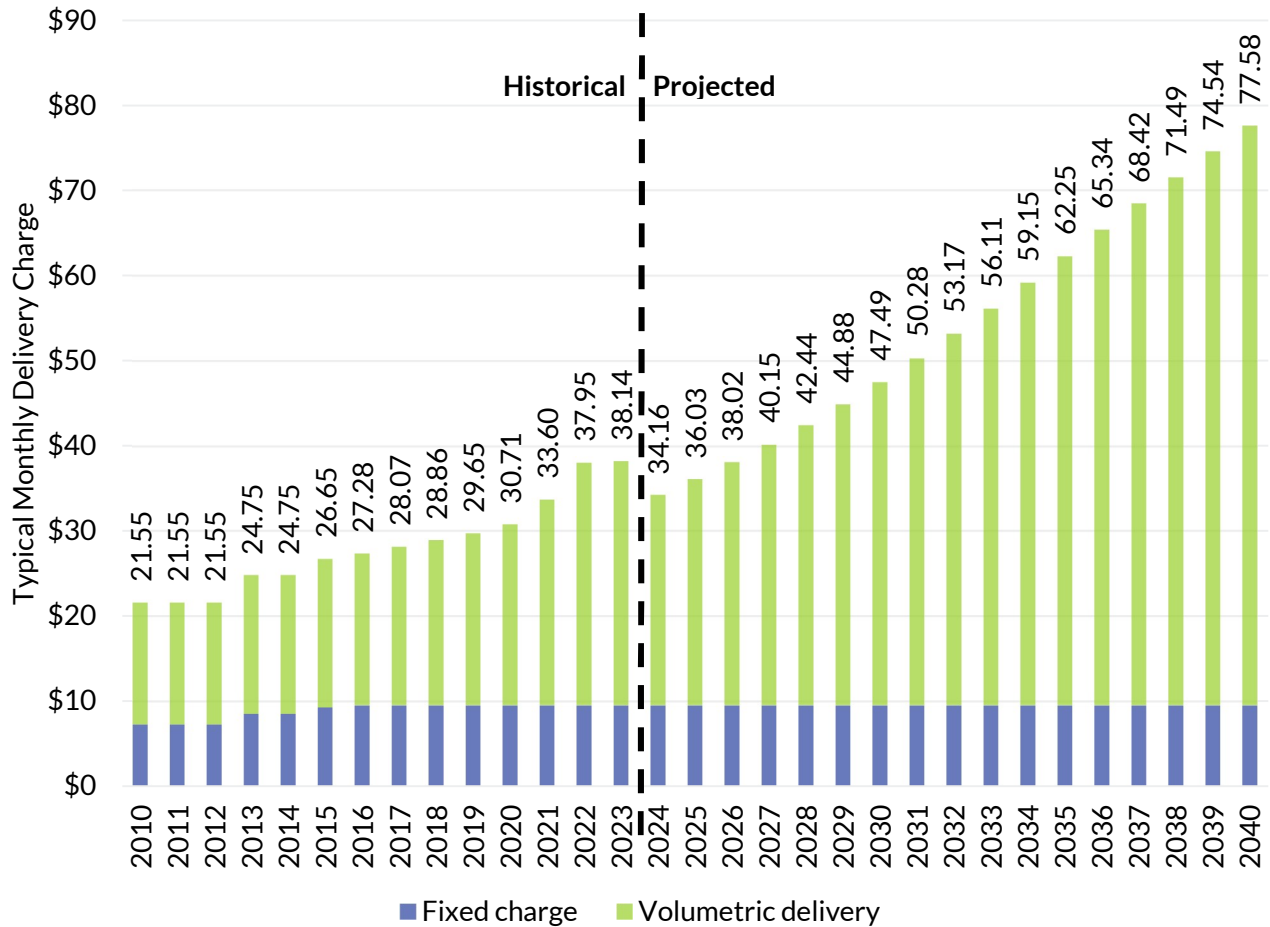
Table 3.5 shows how the volumetric charge for MERC was calculated for 2024; the same process was followed for each year through 2040.

Table 3.5: MERC Projected Volumetric Rate Calculation, 2024

#	Item	Note	2024
1	Revenue Requirement		\$141,612,792
2	Residential Allocation Factor		62.50%
3	Residential Revenue Requirement Allocation	Line 1 x Line 2	\$88,507,995
4	Monthly Charge		\$9.50
5	Residential Bills		2,677,441
6	Fixed Revenues	Line 4 x Line 5	\$25,435,690
7	Volumetric Revenue	Line 3 - Line 6	\$63,072,306
8	Residential Therms		184,132,213
9	Base Volumetric Charge	Line 7 / Line 8	\$0.3425

Figure 3.4 shows the historical (since 2010) and projected (through 2040) typical monthly delivery charges for MERC’s residential customers (i.e., the fixed monthly charge and the base volumetric delivery charge), based on the average monthly residential natural gas consumption for MERC’s customers (72 therms). Monthly delivery charges nearly doubled between 2010 and 2023 and are projected to double again (compared to 2023) by 2040. The monthly delivery charge in 2040 is projected to be about 3.6 times higher than it was in 2010.

Figure 3.4: MERC Typical Residential Monthly Delivery Charges, 2010–2040

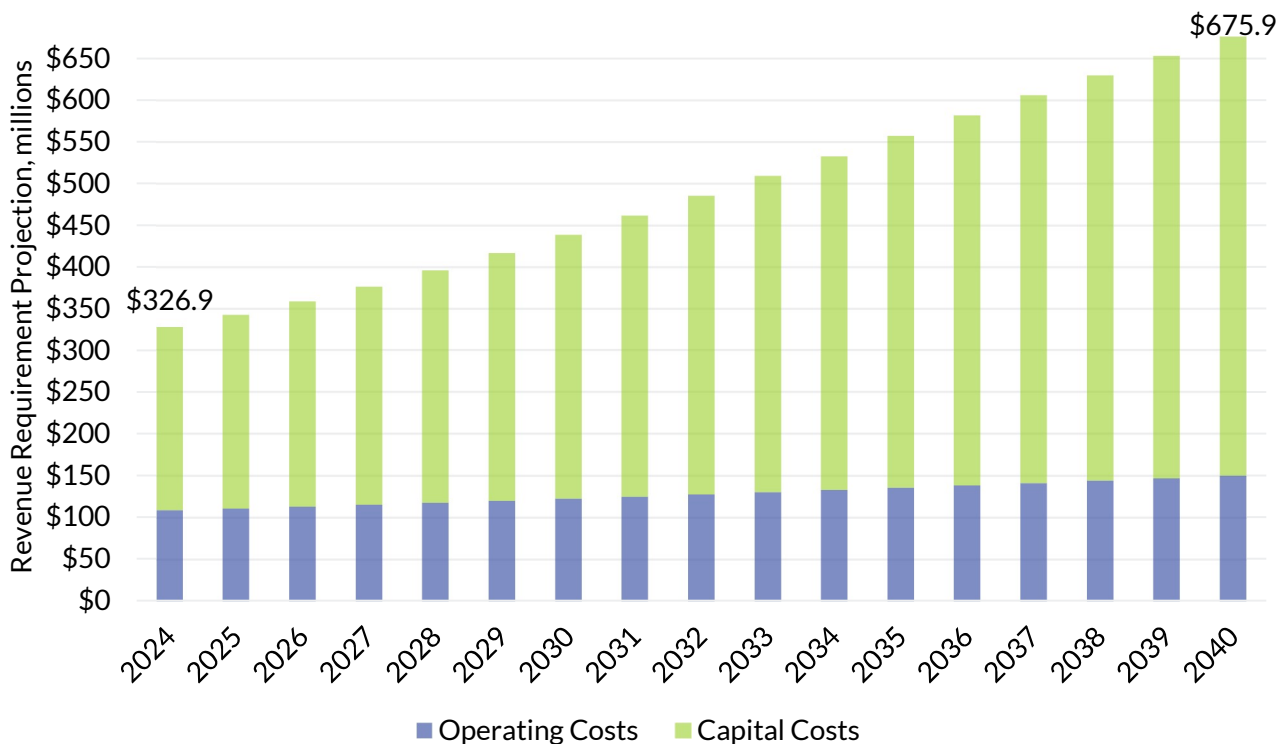


Sources: Historical delivery charges from MN DOC Efilng Dockets 10-977, 13-617, 15-736, 17-563, and 22-504. Projected delivery charges are consultant projections.

3.3 XCEL ENERGY

Figure 3.5 shows the projected revenue requirements for Xcel between 2024 and 2040. The revenue requirement increases from \$327 million in 2024 to nearly \$676 million in 2040.

Figure 3.5: Xcel Revenue Requirements, 2024-2040



Source: Consultant projections.

Table 3.6 shows how the volumetric charge for Xcel was calculated for 2024; the same process was followed for each year through 2040.

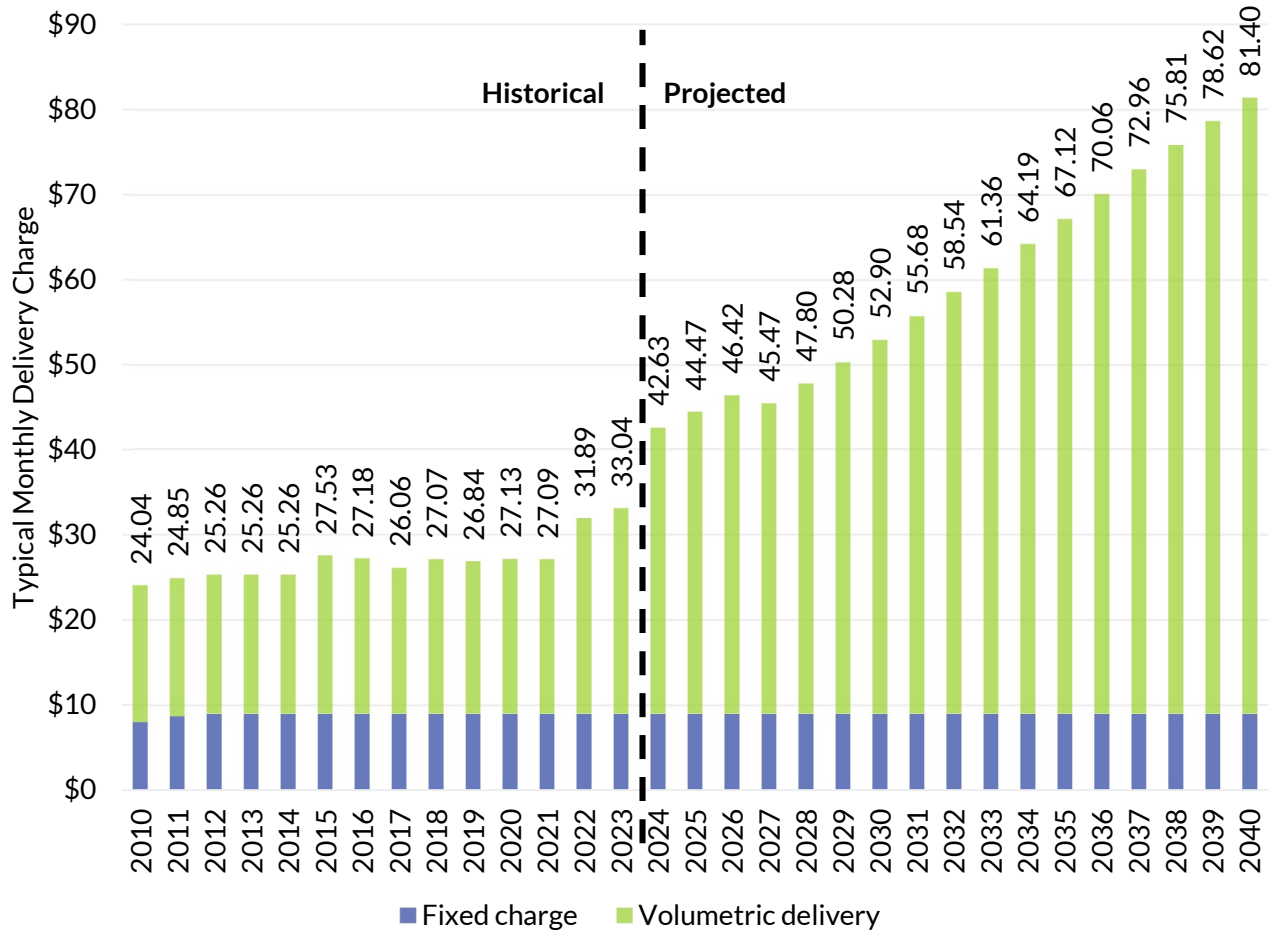
Table 3.6: Xcel Projected Volumetric Rate Calculation, 2024

#	Item	Note	2024
1	Revenue Requirement		\$326,861,433
2	Residential Allocation Factor		64.1406%
3	Residential Revenue Requirement Allocation	Line 1 x Line 2	\$209,650,850
4	Monthly Charge		\$9.00
5	Residential Bills		5,333,095
6	Fixed Revenues	Line 4 x Line 5	\$47,997,855
7	Volumetric Revenue	Line 3 - Line 6	\$161,652,995
8	Residential Therms		390,483,347
9	Base Volumetric Charge	Line 7 / Line 8	\$0.4140

Figure 3.6 shows the historical (since 2010) and projected (through 2040) typical monthly delivery charges for Xcel’s residential customers (i.e., the fixed monthly charge and the base volumetric delivery charge), based on the average monthly residential natural gas consumption for Xcel’s customers (73 therms). The monthly

delivery charge increased by about 40 percent between 2010 and 2023 and is projected to double (compared to 2023) by 2035. The monthly delivery charge in 2040 is projected to be nearly 3.4 times higher than it was in 2010.

Figure 3.6: Xcel Typical Residential Monthly Delivery Charges, 2010–2040



Sources: Historical delivery charges from MN DOC Efilng Dockets 09-1153, 17-895, and 21-678. Projected delivery charges are consultant projections.

SECTION 4 THE FUTURE OF NATURAL GAS IN MINNESOTA

This study has been prepared within the context of multiple interconnected issues in Minnesota's energy sector: the accelerated rate of investment in natural gas infrastructure, the urgent need for action to reduce greenhouse gas emissions, and the need for equity and affordability in utility rates. Each of these issues has significant implications for the state's energy future. The subsections below elaborate on how these issues intersect.

Section 4.1 describes Minnesota's climate goals and identifies the historical contributions from natural gas services to the state's greenhouse gas (GHG) emissions. Next, Section 4.2 presents an alternative bill impact analysis that considers what the future base rates would be in a scenario where—to reduce greenhouse gas emissions—space heating is electrified and gas is used as a backup resource. Section 4.3 then examines the equity implications of higher gas bills as homes and businesses are electrified or converted to other zero-carbon energy sources.

4.1 MINNESOTA'S CLIMATE GOALS

In 2023, the state of Minnesota accelerated benchmarks for the reduction of GHG emissions, setting statutory goals to reach 30 percent reduction by 2025, 50 percent by 2030, and net zero emissions by 2050.²³ In 2021, the legislature also passed the Natural Gas Innovation Act, which permits gas utilities to propose pilot programs to reduce GHG emissions. That Act also directed the Public Utilities Commission to "initiate a proceeding to evaluate changes to natural gas utility regulatory and policy structures needed to meet or exceed Minnesota's GHG emissions reductions goals, including those established in Minnesota Statutes."²⁴

Natural gas use was responsible for about 20 percent of GHG emissions in Minnesota in 2020. Residential and commercial use of natural gas alone was responsible for nearly 10 percent of total state GHG emissions in 2020; moreover, emissions from residential and commercial use of natural gas have increased since 2005 rather than decreasing in line with state emissions targets.²⁵ Figure 4.1 shows GHG emissions from residential and commercial natural gas use, indexed to 2005. While there have been several years where the emissions from residential and commercial natural gas use have been lower than they were in 2005, overall, the trend is that these emissions have increased.

²³ Laws of Minnesota 2023, chapter 60, article 12, section 61, available <https://www.revisor.mn.gov/laws/2023/0/Session+Law/Chapter/60/>.

²⁴ Minnesota Laws 2021 1st Special Session, Chapter 4, Article 8, Sections 20, 21, and 27 (collectively referred to as the Natural Gas Innovation Act), available <https://www.revisor.mn.gov/laws/2021/1/Session+Law/Chapter/4/>.

²⁵ Minnesota Pollution Control Agency Data Services, "Greenhouse Gas Emissions Data," updated January 27, 2023, available <https://public.tableau.com/app/profile/mpca.data.services/viz/GHGemissioninventory/GHGsummarystory>.

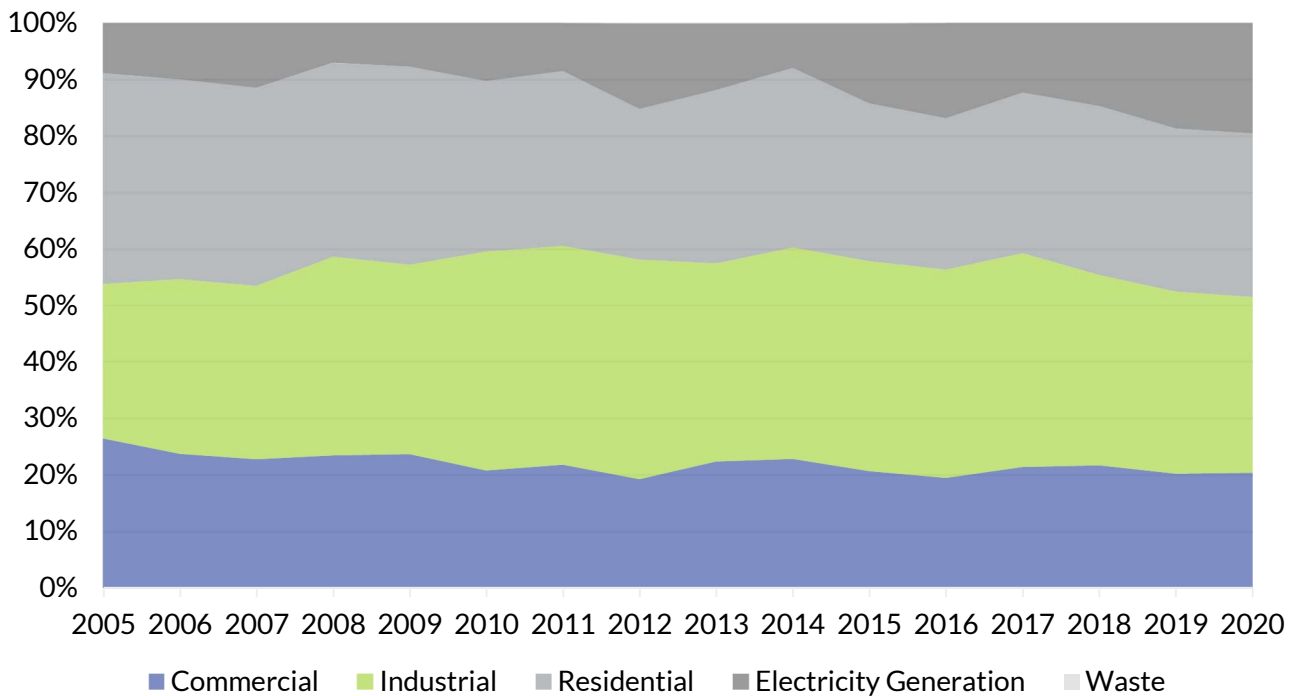
Figure 4.1: GHG Emissions from Residential Natural Gas Use, 2005–2020



Source: Minnesota Pollution Control Agency Data Services, "Greenhouse Gas Emission Data."

Figure 4.2 shows GHG emissions from natural gas by sector since 2005. End-use of natural gas, including usage by the residential, commercial, and industrial sectors, was responsible for more than 80 percent of natural gas GHG emissions in 2020.

Figure 4.2: GHG Emissions from Natural Gas by Sector, 2005–2020



Source: Minnesota Pollution Control Agency Data Services, "Greenhouse Gas Emission Data." The "waste" category includes energy use in waste processing, incinerator fuels, waste incineration, and methane from landfill gas and wastewater treatment.

If the state's climate goals are to be achieved, the current levels of emissions from natural gas end users raises questions about what role natural gas services can play in the state's energy future. Changes in how natural gas is used will have corresponding impacts on the LDCs and their customers. The next subsection examines how a reduction in gas sales might affect the future base rates utilities would need to charge.

4.2 SENSITIVITY ANALYSIS: ELECTRIFICATION OF SPACE HEATING

Stakeholders in Minnesota have begun investigating how the energy sector can decarbonize in order to meet the state's emissions targets. A 2018 report on decarbonizing the electricity grid in Minnesota concluded that meeting the original emissions targets set in 2007 (80 percent reduction by 2050) would require electrification of sectors beyond electricity generation, such as transportation and space heating. It assumed that space heating in the residential and commercial sector would transition to heat pumps and water heating in both sectors would transition to heat pump water heaters. It further recommended that all new construction have electric space and water heating and that old furnaces and water heaters be replaced with heat pumps.²⁶ To reach the new statutory goal of net zero emissions by 2050, all gas currently sold by LDCs will likely have to be replaced with a zero-emissions alternative.

A 2021 report completed with input from Minnesota's natural gas utilities focused on decarbonization of the uses of natural gas. The following scenarios for meeting that target were modeled (all assume the electric grid is fully decarbonized by 2050):

- **Reference Case:** Heat pumps are adopted following a linear trend, half of all buildings receive energy efficiency retrofits, there is no industrial electrification, and the gas distribution system continues to supply conventional natural gas.
- **High electrification:** Almost all buildings are heated by heat pumps with electric resistance heaters as backup, buildings receive energy efficiency retrofits, new buildings are all-electric, and industry is electrified where viable but is otherwise fueled by decarbonized gaseous fuels (such as hydrogen and biogenic and synthetic methane).
- **High electrification with gas backup:** Buildings are primarily heated by heat pumps but have gas backup for the coldest parts of the year (with natural gas gradually replaced by biomethane, synthetic natural gas, and hydrogen), buildings receive energy efficiency retrofits, new buildings are all electric, and industry is electrified where viable but is otherwise fueled by decarbonized gaseous fuels.
- **High decarbonized gas:** Buildings are heated primarily by gaseous fuels (with natural gas gradually replaced by biomethane, synthetic natural gas, and hydrogen), buildings receive energy efficiency retrofits, and industry is fueled by hydrogen produced by renewable energy.

Modeling results from the 2021 study show that there is a range of outcomes for the natural gas sector. The "high electrification" scenario nearly eliminates natural gas sales in the residential and commercial sectors by 2050, the "high electrification with gas backup" scenario sees gas consumption sales continuing but at a steep decline (a 76 percent reduction in gas heating load by 2050), and the "high decarbonized gas" scenario sees gas

²⁶ Vibrant Clean Energy, *Minnesota's Smarter Grid: Pathways Toward a Clean, Reliable and Affordable Transportation and Energy System* (2018), available http://gridlab.org/wp-content/uploads/2019/04/Minnesota_GridLab_Report.pdf.

consumption decline only slightly due to energy efficiency improvements.²⁷ The reduced sales in gas that all these scenarios envision would alter the rate trajectories presented in Section 3 because LDCs would need to collect their revenue requirements over fewer sales.

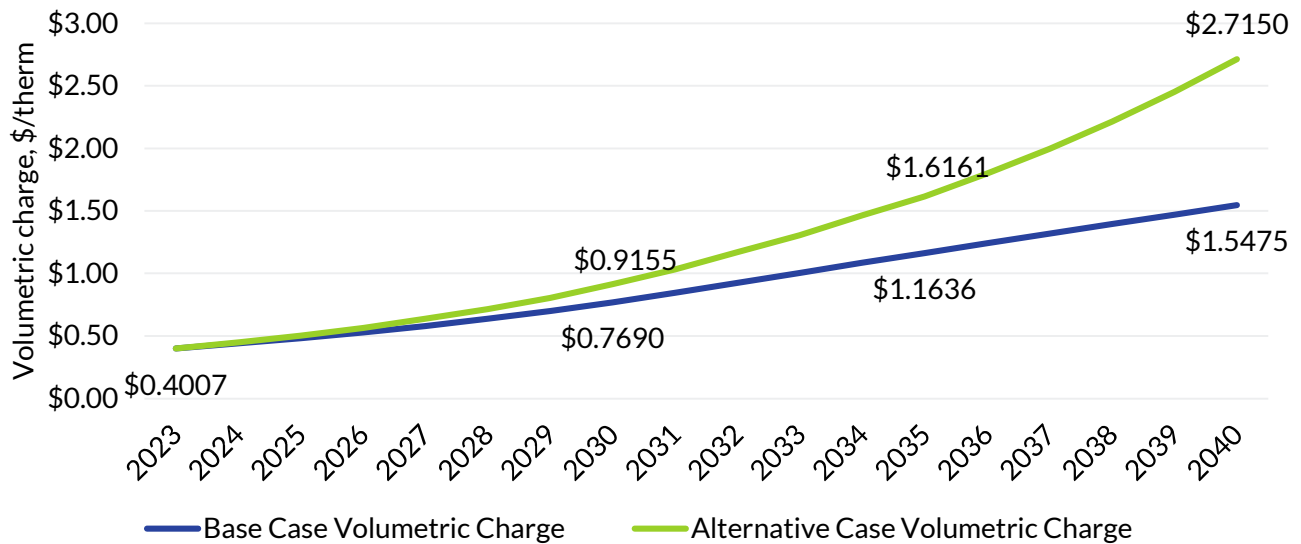
In order to assess the impact of decarbonization on residential gas bills, we developed an alternative scenario with a reduced sales path in line with the “high electrification with gas backup” scenario described above; we chose this scenario because it represents a middle ground between the complete elimination of residential gas sales foreseen in the “high electrification” scenario and the slight decline in gas sales projected in the “high decarbonized gas” scenario. Since existing gas customers are assumed to retain gas services as a backup, we found it reasonable to use the same capital investment and operating cost assumptions as the base case.

To model this scenario, we assumed that starting in 2024 residential gas sales begin to decline to reach a 76 percent reduction compared to current levels by 2050 but kept all other assumptions the same. This has the effect of greatly increasing the base volumetric rate because companies are selling less gas but still have the same revenue requirements described in Section 3. The subsections below describe the effect on volumetric rates for each company.

4.2.1 CENTERPOINT ENERGY

Figure 4.3 compares the volumetric charge under the base case to what it would be in the alternative case of “high electrification with gas backup.”

Figure 4.3: CPE Base and Alternate Case Volumetric Charge Projections



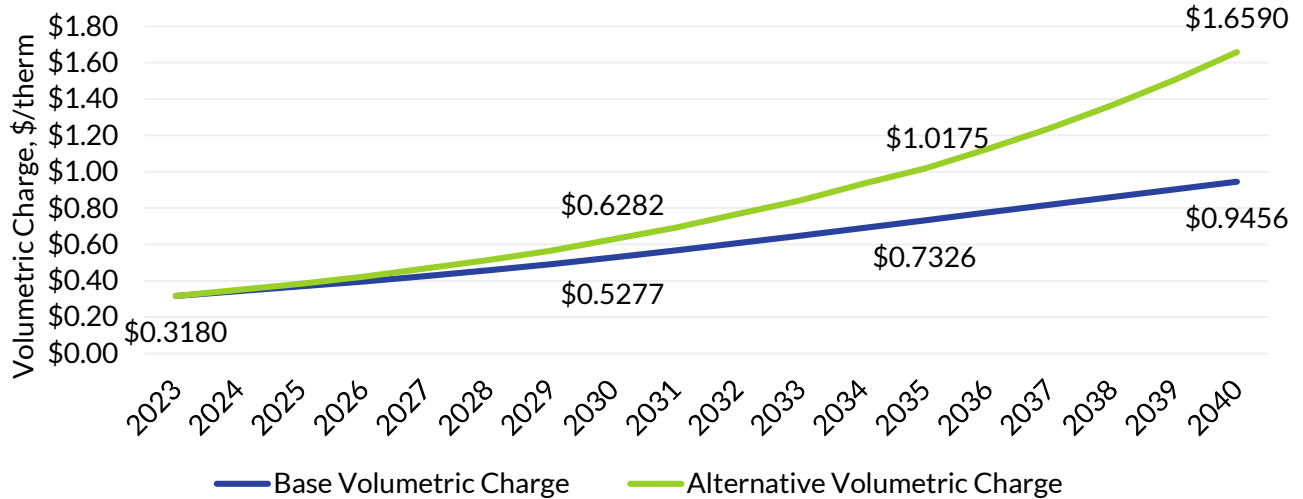
Source: Consultant projections.

²⁷ Center for Energy and Environment and Great Plains Institute, *Decarbonizing Minnesota’s Natural Gas End Uses: Stakeholder Process Summary and Consensus Recommendations* (July 2021), available <https://e21initiative.org/wp-content/uploads/2021/07/Decarbonizing-NG-End-Uses-Stakeholder-Process-Summary.pdf>.

4.2.2 MINNESOTA ENERGY RESOURCES

Figure 4.4 compares the volumetric charge under the base case to what it would be in the alternative case of “high electrification with gas backup.”

Figure 4.4: MERC Base and Alternate Case Volumetric Charge Projections

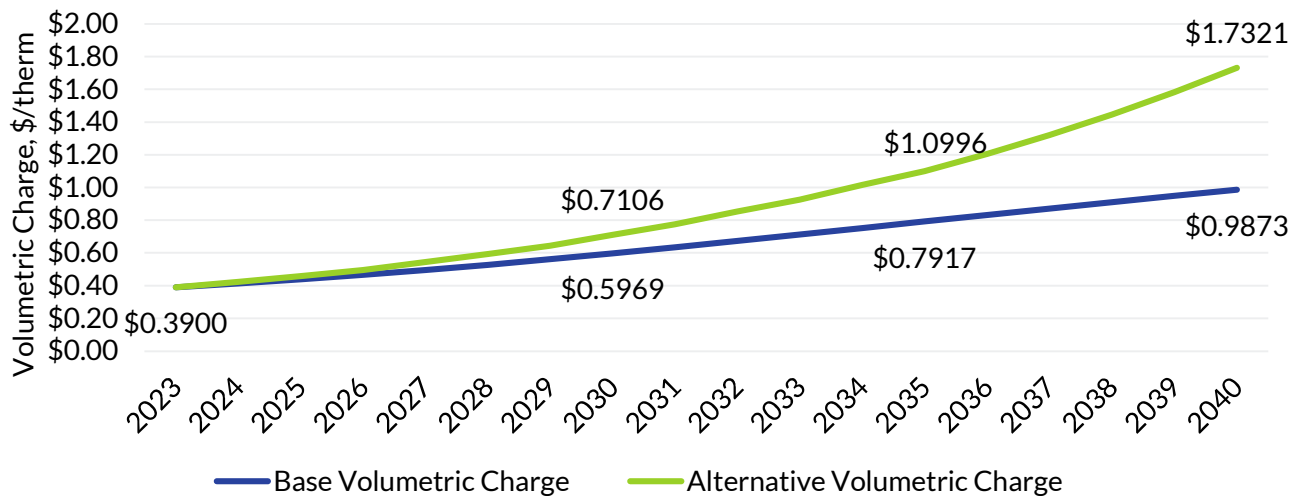


Source: Consultant projections.

4.2.3 XCEL ENERGY

Figure 4.5 compares the volumetric charge under the base case to what it would be in the alternative case of “high electrification with gas backup.”

Figure 4.5: Xcel Base and Alternate Case Volumetric Charge Projections

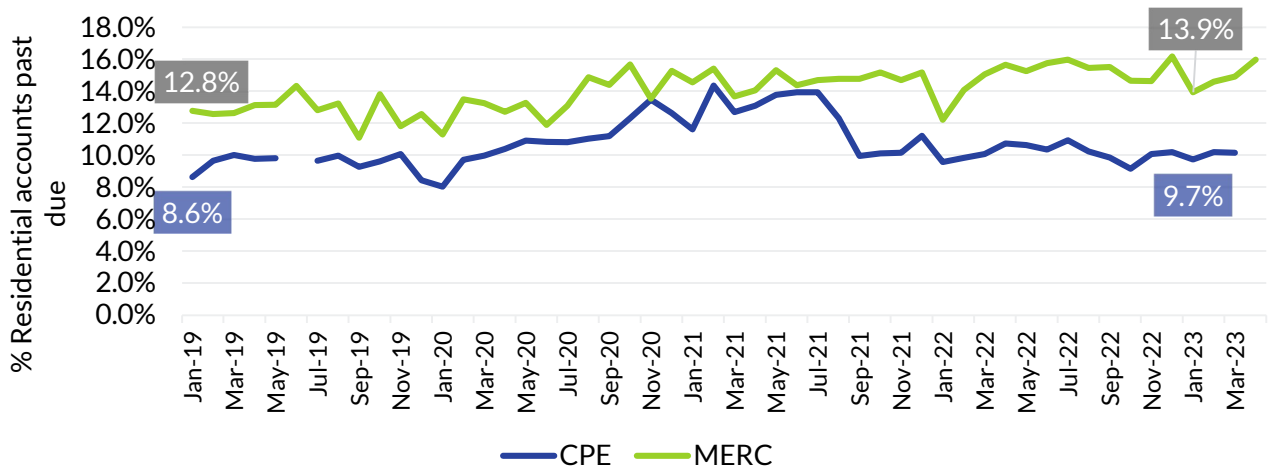


Source: Consultant projections.

4.3 EQUITY CONSIDERATIONS

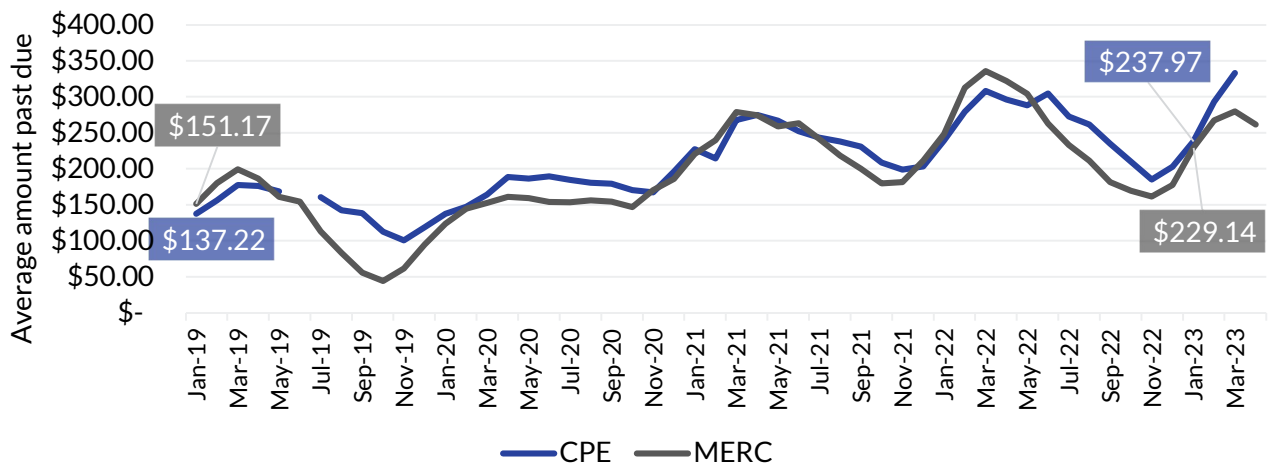
A daunting reality of the trajectory of residential gas bills presented in this study—whether the base case described in Section 3 or the alternative scenario described above—is that many households in Minnesota already have challenges paying bills at the current rate levels. The number of residential customers at Minnesota LDCs with bills over one month past due has risen over the past four years. Figure 4.6 shows that the proportion of residential customers past due at CPE and MERC has increased from January 2019 to March 2023. Not only are more customers falling behind on their bills, but the amount owed is also increasing. Figure 4.7 shows that households’ past-due utility balances at CPE and MERC have skyrocketed over this same period; residential arrearage amounts in 2022 were roughly double their 2019 levels. Note that Xcel was excluded from these figures because the arrears data it submits combines both gas and electricity.

Figure 4.6: Percent of Residential Accounts Past Due by Month, 2019-2023



Source: MN DOC Efilng Dockets 19-02, 20-02, 20-375, 21-02, 22-02, and 23-02.

Figure 4.7: Average Amount Past Due by Month, 2019-2023



Source: MN DOC Efilng Dockets 19-02, 20-02, 20-375, 21-02, 22-02, and 23-02.

The clean energy transition could potentially exacerbate the bill impacts on low-income households. As climate concerns mount and gas bills increase, customers may wish to reduce their gas usage or opt out of using natural gas altogether, turning to alternative heating solutions such as electric heat pumps or, on a community scale, networked geothermal systems. As they do so, costs for other customers will rise even more, leading more customers to reduce their usage or leave the gas system, and so on. This potentiality has been called the “utility death spiral.” The residential natural gas customers who remain are likely to be those who are least likely to be able to afford investing in alternative heating solutions—and who are also least likely to be able to afford ever-increasing gas bills.²⁸

Low-income customers are much less likely to have the capital required to invest in electric heating solutions—even solutions that are more efficient and lower cost over the long term—or to improve the energy efficiency of their homes. Moreover, low-income customers are more likely to be renters who have little choice in how their homes are heated.²⁹ They are also less likely to be reached by utility-administered energy efficiency programs, which are often untargeted; even if programs are targeted at low-income customers, customers’ needs are likely to far exceed available resources.³⁰

Though gas *rates* are projected to increase even more quickly under the “high electrification with gas backup” scenario, higher rates will be offset by reduced usage for the majority of households that are assumed will invest in full electrification of their gas end uses. For these high electrification households, or “secondary gas” households that would switch to relying on gas only as backup energy source, the reduction in their gas usage by the average amount (76 percent) would see no change in the delivery portion of its monthly *bill* in this scenario as compared with the base case. However, a household that is unable to invest in electric heat and energy efficiency solutions will still rely on gas to meet their energy needs. These legacy “primary gas” households will see significant increases in the delivery portion of their gas bills as they will left paying the higher rates on the same levels of consumption.

4.3.1 CENTERPOINT ENERGY

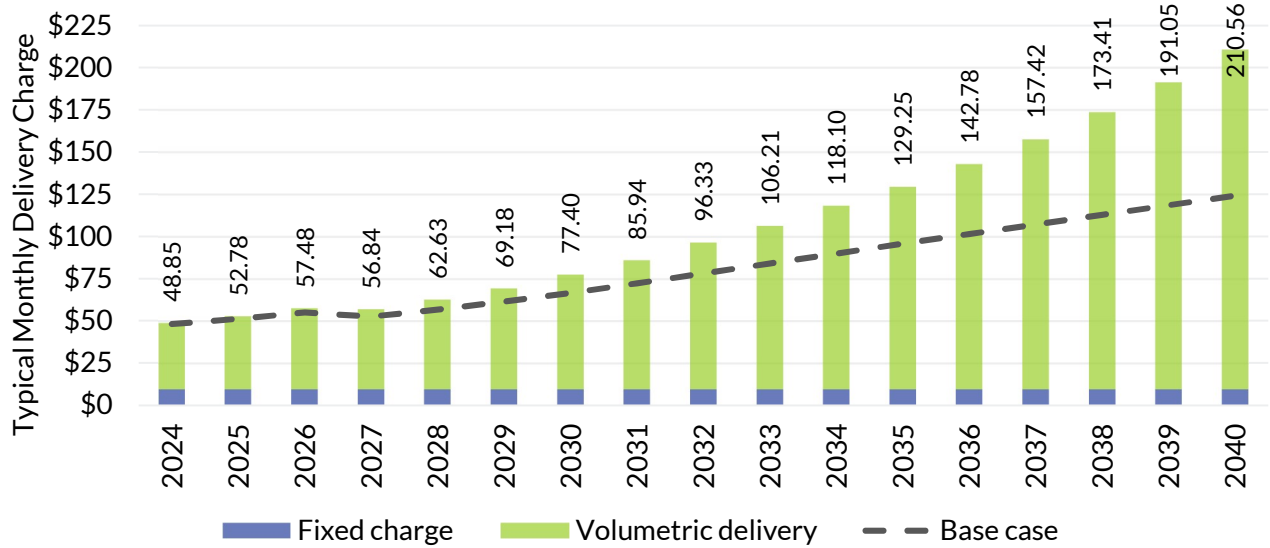
Figure 4.8 shows what the typical monthly bill would be under the alternative “high electrification with gas backup” case for a legacy primary-gas household in CenterPoint’s service territory that does not transition primarily to electric heating or receive the other energy improvements assumed of a typical household in this scenario. The dotted line shows the monthly bill projections under the base case described in Section 3. Typical monthly bills for the legacy primary-gas households under this alternative case are 10 percent higher than the base case by 2028, 35 percent higher by 2035, and 70 percent higher by 2040.

²⁸ Center for Energy and Environment and Great Plains Institute, *Decarbonizing Minnesota’s Natural Gas End Uses*, pp.52–53.

²⁹ California Energy Commission, *The Challenge of Retail Gas in California’s Low-Carbon Future: Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use* (April 2020), available at <https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf>.

³⁰ Ariel Dreihobl, Lauren Ross, and Roxana Ayala, *How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden Across the United States*, American Council for an Energy-Efficient Economy [ACEEE] (September 2020), available at <https://www.aceee.org/sites/default/files/pdfs/u2006.pdf>.

Figure 4.8: CPE Alternate Case Typical Monthly Bill Projections, Legacy Primary-Gas Household

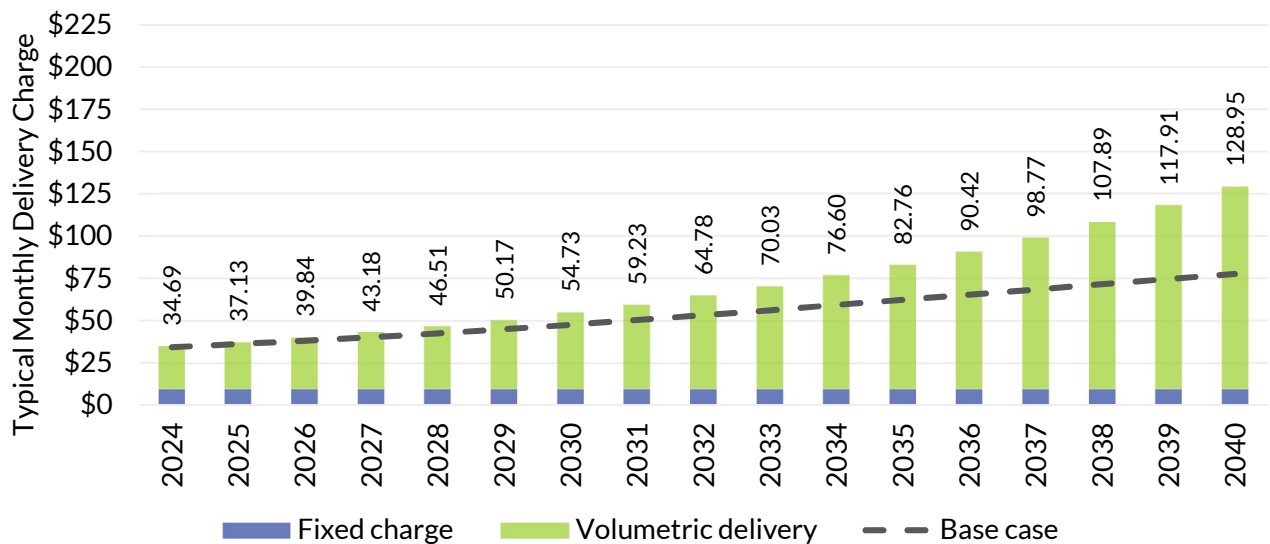


Source: Consultant projections.

4.3.2 MINNESOTA ENERGY RESOURCES

Figure 4.9 shows what the typical monthly bill would be under the alternative “high electrification with gas backup” case for a legacy primary-gas household in MERC’s service territory. The dotted line shows the monthly bill projections under the base case described in Section 3. Typical monthly bills for legacy primary-gas households under this alternative case are 10 percent higher than the base case by 2028, 25 percent higher by 2033, and 66 percent higher by 2040.

Figure 4.9: MERC Alternate Case Typical Monthly Bill Projections, Legacy Primary-Gas Household

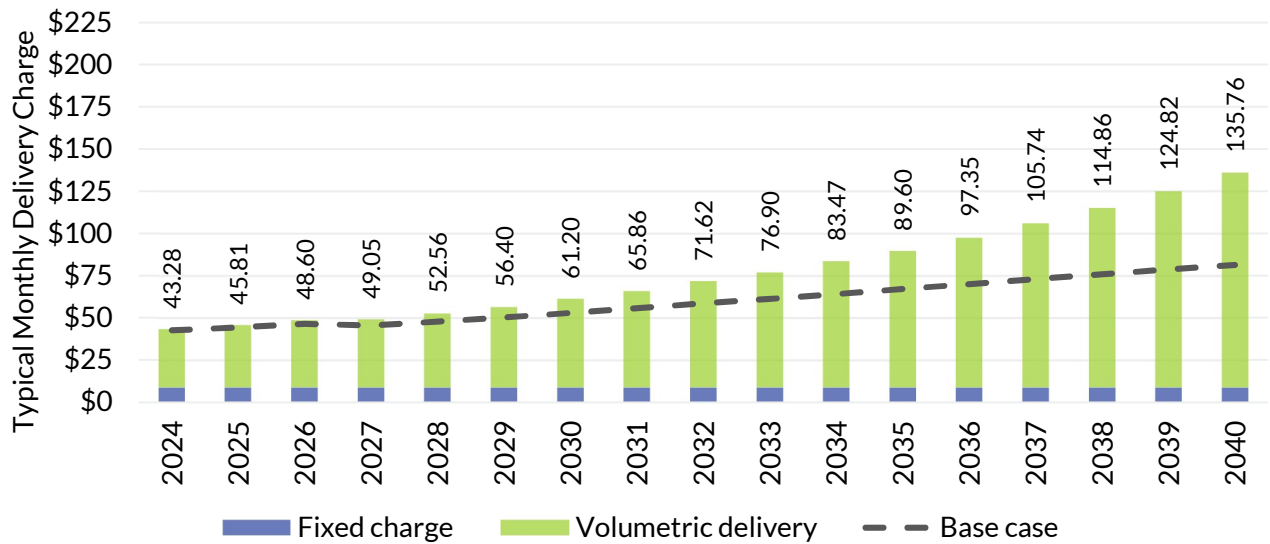


Source: Consultant projections.

4.3.3 XCEL ENERGY

Figure 4.10 shows what the typical monthly bill would be under the alternative “high electrification with gas backup” case for a legacy household in Xcel’s service territory. The dotted line shows the monthly bill projections under the base case described in Section 3. Typical monthly bills for legacy primary-gas households under this alternative case are 10 percent higher than the base case by 2028, 25 percent higher by 2033, and 67 percent higher by 2040.

Figure 4.10: Xcel Alternate Case Typical Monthly Bill Projections, Legacy Primary-Gas Household



Source: Consultant projections.

The vulnerabilities of low-income households to rate increases and economic transitions should not be a surprise. The COVID-19 pandemic and subsequent period of high inflation have highlighted the disproportionate impact of utility costs on low-income and vulnerable communities, who already face higher energy burdens. In response to the COVID-19 crisis, regulators, utilities, and policymakers were prompted to reevaluate rate structures and assistance programs to ensure that essential services remained accessible and affordable for all customers.

The clean energy transition envisioned for Minnesota requires these same stakeholders to continue to monitor the impact on low-income households and put additional protections in place to ensure essential energy services remain affordable.

SECTION 5 CONCLUSION

This study considers what the future rate impacts may be if gas utilities continue to make capital investments at the rates planned by the Minnesota LDCs. We have tried to provide a set of analyses and projections to inform readers' considerations regarding continued higher levels of investment into Minnesota's natural gas infrastructure. The study relies on publicly available data and information to present a scenario of the annual future gas capital investments and the corresponding residential bill impacts based on what the Minnesota LDCs themselves have presented to their investors and state and federal regulators.

Our projections estimate that, to achieve the financial targets the companies have presented to investors, the Minnesota LDCs will need to spend a combined \$7.5 billion from 2023 to 2031 and then would spend another \$11.7 billion through 2040 if they increase investments just at the rate of inflation. Combined, we project that the Minnesota LDCs could spend more than \$19 billion from 2023 through 2040 on gas infrastructure in Minnesota. If the Minnesota LDCs make investments at the forecasted levels the base rate portion of the average customer bill in 2040 will be two to three times higher than it is 2023. By 2040, the residential customers of CPE, MERC, and Xcel could be asked to pay more than \$1.87 billion per year just for the transportation costs to deliver gas to their homes.

The research presented in the study raises doubts as to whether this level of investment and corresponding base rate increase is justified based on safety or state policy priorities.

- **Minnesota LDCs are operating some of the safest systems in the country.** Compared to other LDC systems nationally, the pipeline infrastructure of the Minnesota LDCs is newer, has fewer remaining pipes made of leak-prone materials; and has lower incidence of leaks.
- **Minnesota GHG emissions goals aim to reach a 30 percent reduction by 2025, 50 percent by 2030, and net zero emissions by 2050.** These clean energy goals raise questions about the role that natural gas can play in the state's low carbon future. Given that natural gas usage by the residential and commercial sector alone made up 10 percent of the state's GHG emissions in 2020 there will need to be a focus on ways to transition some or all gas users to zero-emission alternatives.

Ultimately, it is up to the state's policy makers, regulators, and other stakeholders to develop their own conclusions on the relevance of gas infrastructure investment in Minnesota's clean energy future. The decisions that need to be made today on gas infrastructure investment will have long-term impacts on the state's policy goals and the affordability of essential energy services. We hope this study allows for a critical discussion on these urgent decisions.

APPENDIX A PHMSA LEAK CAUSE DEFINITIONS

Appendix Table A.1: PHMSA Leak Cause Definitions

Corrosion failure	Leak caused by galvanic, atmospheric, stray current, microbiological, or other corrosive action.	Steel
Natural force damage	Leak caused by outside forces attributable to causes NOT involving humans, such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, high winds.	Any
Excavation damage	Leak resulting directly from excavation damage by operator's personnel (oftentimes referred to as "first party" excavation damage), by the operator's contractor (oftentimes referred to as "second party" excavation damage), or by people or contractors not associated with the operator (oftentimes referred to as "third party" excavation damage).	Any
Other outside force damage	Leak resulting from outside force damage, other than excavation damage or natural forces such as: nearby man-made explosion, damage by a car/truck, damage by a boat/barge/other maritime equipment, prior mechanical damage, vandalism, terrorism, or theft.	Any
Pipe, weld, or joint failure	Leak resulting from a material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, or in-service stresses such as vibration, fatigue and environmental cracking.	Cast iron (joint), plastic (pipe), and steel (weld)
Equipment failure (non-pipe)	Leak on a non-pipe component caused by malfunctions of control and relief equipment including regulators, valves, meters, compressors, or other instrumentation or functional equipment. Failures may be from threaded components, flanges, collars, couplings and broken or cracked components, or from O-Ring failures, gasket failures, seal failures, and failures in packing or similar leaks.	Any
Incorrect operation	Leak resulting from inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error.	Any
Other cause	Leak resulting from any other cause not attributable to the above causes. Operators are instructed to make a best effort to assign a specific leak cause before choosing the Other cause category.	Any