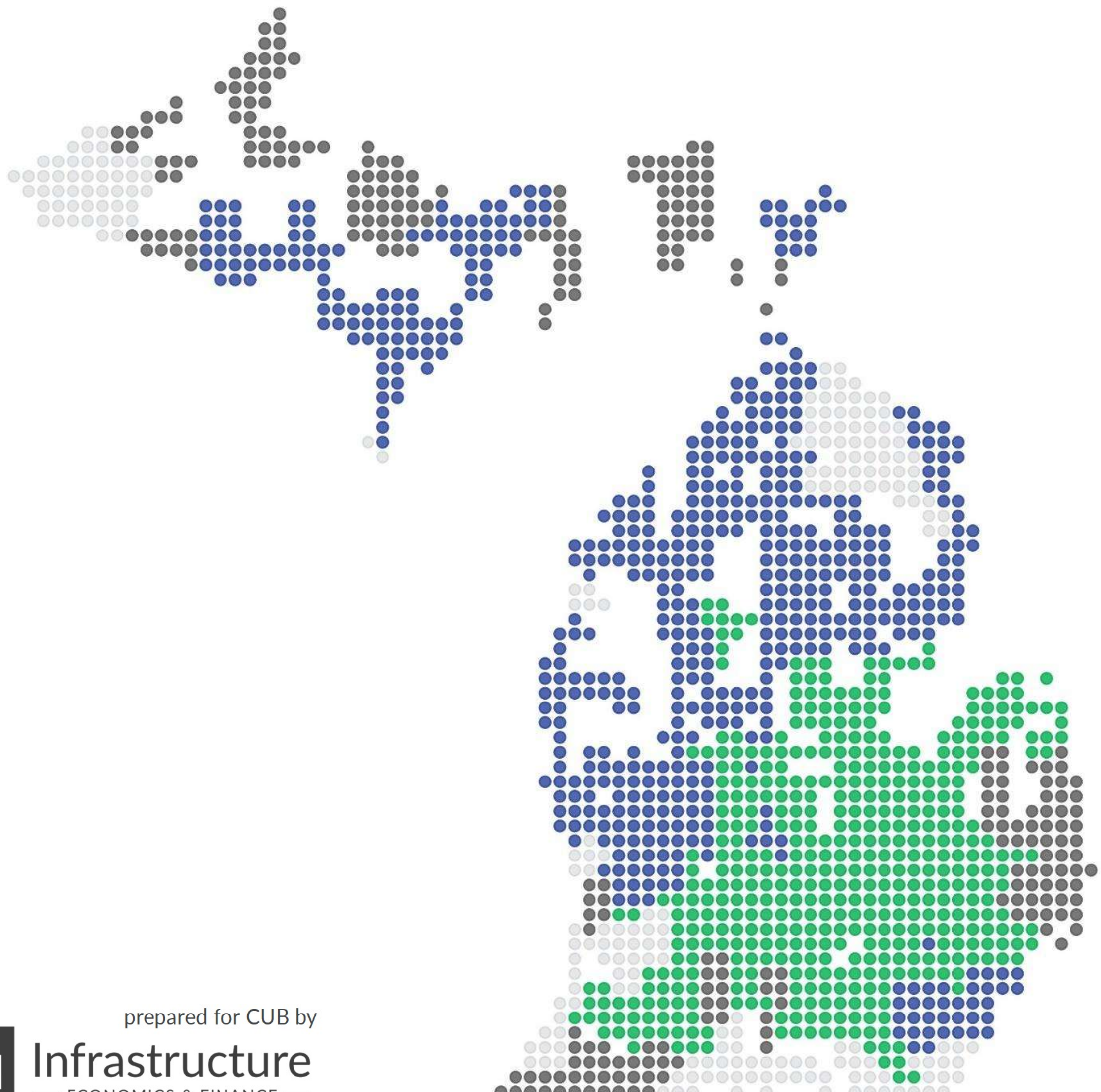
Investor-Owned Utility Gas Distribution Capital Expenditure

A Study on the Potential Bill Impacts of Business-as-Usual Investment in Michigan

March 2025



prepared for CUB by

DH Infrastructure
ECONOMICS & FINANCE

ABOUT CUB

The Citizens Utility Board (CUB) of Michigan was formed in 2018 to represent the interests of residential energy customers across the state of Michigan. CUB educates and engages Michigan consumers in support of cost-effective investment in energy efficiency and renewable energy and against unfair rate increase requests.

CUB gives a voice to Michigan utility customers and helps to ensure that citizens of the state pay the lowest reasonable rate for utility services and also benefit from the environmental implications of investment in clean energy. CUB of MI is a nonpartisan, nonprofit organization whose members are individual residential customers of Michigan's energy utilities. For more information visit *www.cubofmichigan.org*.

ACKNOWLEDGEMENTS AND CONTRIBUTIONS

This report was prepared for CUB by ***DHInfrastructure***, a consulting firm based in Northampton, MA.

Brendan Larkin-Connolly served as the primary author and led the forecasting and financial modeling. Additional contributions to the report were made by Nicole Rosenthal and Margaret Hylton, who provided valuable input and expertise throughout the development of this study.

Broderick Dodd provided research assistance, modeling, and data collection support.

Douglas Jester and Matthew Bandyk of ***5 Lakes Energy*** provided technical review and constructive feedback which substantially strengthened this analysis.

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• EXECUTIVE SUMMARY

Michigan's gas utilities have dramatically accelerated their infrastructure investments over the past decade. Combined annual capital expenditures by the state's three largest gas utilities—Consumers Energy (Consumers), DTE Energy Gas Company (DTE), and SEMCO Energy Gas Company (SEMCO)—have tripled, growing from $578 million in 2013 to $1,739 million in 2023. The scale of these annual investments is striking: the utilities now spend more on gas infrastructure each year than Detroit's entire annual capital budget ($650 million) and nearly fifteen times more than what has been spent to date addressing the Flint water crisis ($116 million as of 2024).[1]

This study evaluates the long-term implications of this investment trajectory by analyzing these utilities' existing capital investment plans and estimating how their planned investments could affect residential gas customer bills through 2050. The analysis employs a three-step approach:

1. Projecting future capital expenditures and rate base through 2050 based on published utility investment plans and historical trends
2. Calculating annual revenue requirements needed to recover these investments
3. Translating revenue requirements into projected base rates and typical residential customer bills

The projections represent a "business-as-usual" (BAU) scenario, assuming utilities maintain their current investment approaches, with stable customer bases and consistent gas sales.

KEY FINDINGS

Future infrastructure investments and implications on revenue requirements

- The first step in developing the projected bill impacts of BAU investments was to develop a BAU capital investment scenario for each company.
- Between 2013 and 2023 the combined annual investments of the three companies increased at a rate of 11.6 percent per year.[2] This rise in the rate of investment has been led by DTE with an average annual growth rate in capital expenditures (CAPEX) of 13.6 percent per year, followed by Consumers at 11.2 percent per year, and SEMCO at 6.3 percent per year. If the three companies continue to increase capital expenditure at these same rates, then between 2025 and 2050 they will have invested a total of $324,291 million ($324 billion):
    - Consumers: $164,412 million ($164.4 billion)
    - DTE: $155,009 million ($155 billion)
    - SEMCO: $4,869 million ($4.9 billion)
- The numbers above may seem like fantasy. It is important to understand these are not the result of any sophisticated forecasting technique that employed a myriad of unrealistic assumptions. Rather, these totals are simply the sum of annual investments from 2025 to 2050 of each company's 2023

[1] City of Detroit's proposed capital budget for fiscal years 2024-2025 from the 2024-2028 Capital Plan (*https://detroitmi.gov/document/proposed-fy2024-2028-capital-agenda*). According to City of Flint, $97.01 million has been spent on the Lead Service Line Replacement Cost since 2013 (*https://www.cityofflint.com/progress-report-on-flint-water/*). When adjusted for average inflation over this period this amount in real 2024 dollars is $116 million.

[2] Compound annual growth of 11.6% = ($1,739.1 million CAPEX in 2023 / $577.9 million CAPEX in 2013)$^{1/10}$ – 1

capital expenditure level increased annually at the same compound annual growth rate (d) that investments have increased over the 2013 to 2023 period.

- While it is important that readers understand the current trajectory of capital investments, we inevitably decided that it would be unrealistic to assume for a BAU scenario that the companies would continue to make investments at the same accelerated rate. This study takes a much more conservative approach to projecting future capital expenditure by relying strictly on the annual investments presented in any capital investment plans submitted by the three companies in recent proceedings before the Michigan Public Service Commission (MPSC). We take the investment amounts included in the capital plans for all the years covered by the plan and then at the end of the plan assume that investments grow at the modest rate of one percent each year.
- Based on this approach this study projects that the three utilities are on track to invest a total of approximately $57,666 million in gas infrastructure between 2025 and 2050:[3]
    - Consumers: $33,709 million ($33.7 billion)
    - DTE: $21,082 million ($21.1 billion)
    - SEMCO: $2,875 million ($2.9 billion)
- To compensate the companies for these investments customers will be asked to pay multiples of these investment amounts through base rates. Approximately $77,819 million (63%) of customer payments from 2025 to 2050 will go toward compensating the companies for the capital investments made over this period.
- This amount is also not the only payments that will be made toward capital investments. Customers will also still need to make $45,396 million in payments for investments made prior to 2025. In total, customers are projected to pay about $123,217 million ($123.2 billion) through base rates toward capital-related costs:
    - Consumers: $68,923 million ($68.9 billion)
    - DTE: $48,051 million ($48.1 billion)
    - SEMCO: $6,243 million ($6.2 billion)
- Why are amounts paid for capital costs through base rates so much greater than the initial investment amounts?
    - Capital costs are reflected in base rates as depreciation (the "return of" the initial investment) and an allowed rate of return on utility rate base equal to the utility's weighted average cost of capital (a "return on" the initial investment).
    - Utilities are assessed property taxes on the current value of the utility plant, which means that higher rates of investment also drive increases in property tax expenses.
    - For every $1 in capital invested, customers are expected to pay anywhere from $2 to $4 in revenues depending on the service life of the investment.

Projected rate impacts

- To understand the impact of the investment driven increases in revenue requirements on customers, base rates were calculated using the revenue allocation and billing determinants from each company's most recent base rate case.

[3] Note that 2024 capital investments also had to be projected due to the fact that when the study was prepared information on the actual capital investments were only available through December 31, 2023. For the purpose of relevance, we focus on the 2025 to 2050 period when discussing the projected investments.

- Under a BAU scenario with a stable customer base, the residential bills are projected to increase substantially by 2050 as compared to the 2025 typical customer monthly bill:[4]
    - Consumers: 158 percent increase (from $74.62 to $192.35 monthly)
    - DTE: 120 percent increase (from $80.38 to $177.22 monthly)
    - SEMCO: 106 percent increase (from $62.68 to $129.12 monthly)
- These projections likely underestimate the actual rate impacts as they do not account for potential customer migration away from natural gas.

Climate policy implications

- Michigan has set a goal to reduce greenhouse gas emissions by 52 percent of 2005 levels by 2030 and to achieve net-zero emissions by 2050
- The projected $58 billion in gas infrastructure that the state's three largest Local Distribution Companies (LDC's) are on track to spend not only appears to contradict these goals, but also actively makes achieving these targets more difficult by potentially maintaining current levels of emissions from gas combustion
- Natural gas currently accounts for about 23 percent of Michigan's greenhouse gas emissions (not including gas used in electricity generation)
- Meeting the state's emission reduction targets while maintaining current levels of gas consumption would require:
    - A 56 percent reduction in emissions from all other sectors by 2030
    - All other sectors to achieve negative emissions by 2050 to offset gas emissions.

Key Challenges

This report identifies several critical challenges related to the projection results and their implications for the state's climate goals that require attention from state regulators and policymakers:

- **Infrastructure Planning**: Current accelerated main replacement program strategies take a wholesale replacement approach that commits utilities to decades of infrastructure investment without considering future system needs in a decarbonized economy.
- **Rate Design**: Existing regulatory frameworks designed for growing or stable gas demand may be inappropriate as climate policies and market forces drive electrification.
- **Equity Concerns**: There is a significant risk of vulnerable populations bearing a disproportionate share of transition costs while facing greater barriers to accessing benefits of electrification.

Recommendations

The findings of the study suggest that continuing BAU investment in gas infrastructure creates risks for both ratepayers and utilities while potentially hindering achievement of state climate goals. However, with proper planning and policy frameworks, Michigan has an opportunity to manage an orderly transition that ensures safety and reliability while advancing climate goals and protecting vulnerable customers.

[4] Typical customer usage was estimated by dividing the residential volumetric sales by the number of bills as presented in the revenue proofs of each company's most recent base rate case: 7.72 Mcf/month for Consumers; 7.54 Mcf/month for DTE; and 7.96 Dth /month for SEMCO.

To promote dialogue on these issues, the report presents several ideas for steps Michigan stakeholders can take to start addressing these challenges.

- **Infrastructure Planning Reform**
  - Shift from wholesale replacement to risk-based project selection
  - Require evaluation of non-pipe alternatives
  - Establish clear metrics for measuring alignment with climate goals
  - Implement joint gas-electric system planning requirements
- **Regulatory Framework Updates**
  - Shorten depreciation schedules for new investments
  - Create incentives for maintenance rather than replacement and expansion
  - Develop frameworks for managing stranded asset risks
- **Equity Protection Measures**
  - Develop targeted electrification incentives for low-income households
  - Create transition assistance funds
  - Implement income-based rates or bill assistance programs
  - Establish requirements for tracking demographic impacts

SECTION 1 INTRODUCTION

The Citizens Utility Board (CUB) of Michigan asked DHInfrastructure to evaluate the existing capital investment plans of Michigan's three largest local gas distribution companies (hereafter referred to as "the LDCs") and to estimate how these planned investments could increase residential gas customer bills over the next 25 years.[5] The companies included in this study are Consumers Company (Consumers or CE), DTE Energy Gas Company (DTE), and SEMCO. This report provides projections for the capital expenditures these companies are currently on a path to make from 2024 to 2050, develops corresponding estimates for the revenue that the companies will need to collect from customers over this same period (i.e., each company's "revenue requirement"), and calculates the resulting monthly gas bills for typical residential customers.[6]

These projections represent a business-as-usual or "BAU" scenario - our best estimate of how gas bills will evolve if capital expenditures, operating costs, number of customers, and gas sales continue to reflect current patterns. However, this scenario appears increasingly unlikely. Michigan, like many other states and nations, has made ambitious climate commitments, including achieving carbon neutrality by 2050. Our aim is not to argue against any future role for the gas sector in Michigan, but rather to provide stakeholders with information about the current investment trajectory so they can evaluate whether it aligns with the state's economic, environmental, and financial interests.

The remainder of this section includes a summary of the recent trends in LDC capital investments that are the impetus of this study (Section 1.1), an explanation of the approach used to develop the projections in the study (Section 1.2) and an overview of the remaining sections of this report (Section 1.3).

1.1 LDC CAPITAL INVESTMENT TRENDS

LDCs are capital-intensive businesses, requiring regular and substantial infrastructure investments. Many privately owned LDCs in the United States, including Michigan, are regulated using a "rate-of-return" approach. This approach aims to balance the interests of customers and investors by providing a reasonable return on investment and capping profits at a set percentage of the utility's investments.

Once an investment is considered "utility plant-in-service," the LDC may begin recovering costs through base rates. "Utility plant" is the set of capital infrastructure investments made by the LDCs. This plant is considered "in-service" only when it is fully installed and operational. Under the rate-of-return approach, base rates allow LDCs to receive a "return on" the undepreciated value of their investments (i.e., a return on equity) and a "return of" the investment (i.e., depreciation expenses). This return is collected through base rates until the utility plant is fully depreciated. The service life used to determine depreciation rates for gas plant usually range from a low of five years for items such as computer equipment, to a high of 80 years for transmission

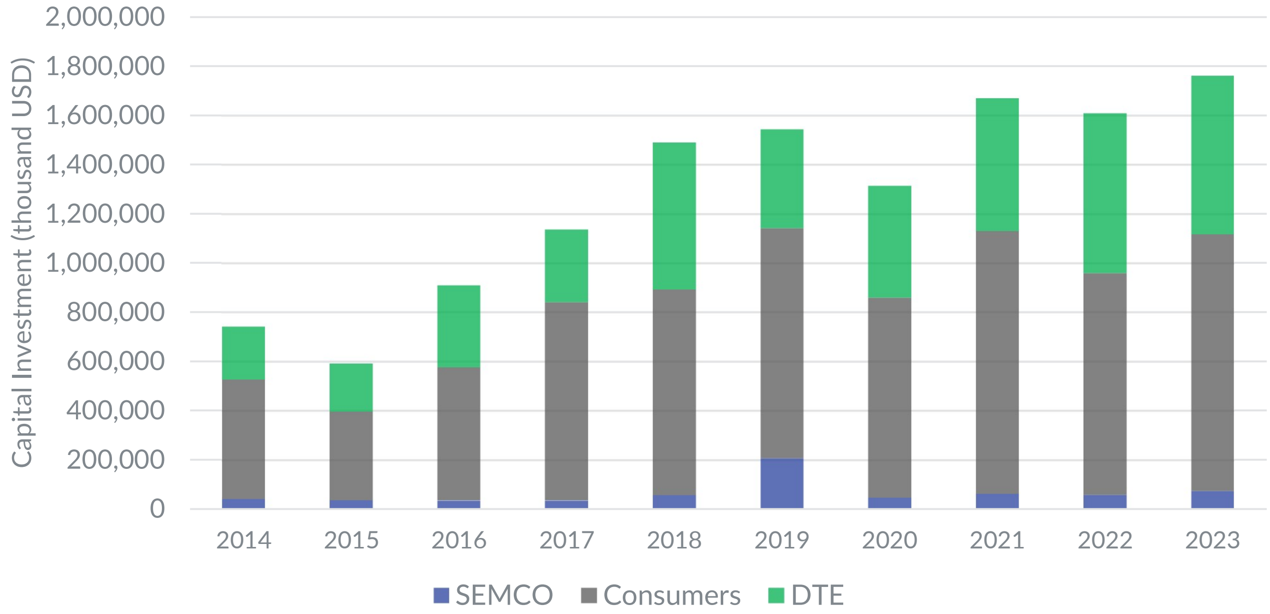
[5] DHInfrastructure is a consulting firm based in Northampton, Massachusetts that specializes in providing economic and financial advice on infrastructure and utility regulation.

[6] We define the "typical" residential customer as a customer with monthly usage equal to the average monthly usage for each company. This is 7.72 Mcf/month for Consumers, 7.54 MCf/month for DTE, and 7.96 Dth/month for SEMCO.

mains and steel distribution mains.[7] The service life of the LDC's core categories of investment are 30-35 years for meters, 40-45 years for service lines, and 50-60 years for plastic mains. This means that customers will pay the costs of the largest investment categories for around 30-60 years.

Michigan LDCs have steadily increased annual capital investments in utility plant over the past decade. Figure 1.1 shows capital investments for Michigan's LDCs since 2014. Over this period, the combined annual expenditure on capital additions by the three utilities has grown from 740 million in 2014 to over 1.7 billion in 2023.

Figure 1.1: Natural Gas Utility Capital Investment in Michigan, 2014-2023



Source: Annual additions to plant in service compiled from each LDC's annual reports filed over the last 10 years.

Table 1.1 shows the CAGR in utility plant-in-service for the LDCs. The CAGR ranged from 6.2 to 9.3 percent over the last 10 years.

Table 1.1: Utility Plant-in-Service and Capital Additions by Company, 2014-2023

Utility	Utility Plant In Service (USD, Start Of 2014)	Utility Plant in Service (USD, end of 2023)	10-year CAGR in Utility Plant in Service
DTE	3,973,987,714	7,246,678,716	6.19%
SEMCO	672,544,524	1,156,774,824	5.57%
Consumers	4,501,827,550	10,902,508,563	9.25%

Source: Start of year and end of year plant-in-service data compiled from each LDC's annual reports filed over the last 10 years.

For perspective on this rate of annual expenditure, Figure 1.2 compares the capital additions made by the three companies in 2021, 2022, and 2023 to other capital outlays on infrastructure in Michigan (in 2024 dollars). Combined annual expenditures of the LDCs ranged between $1.6 to $1.8 billion from 2021 through 2023 (nominal dollars not inflation adjusted). Some key points to take away from the comparisons in the figure below:

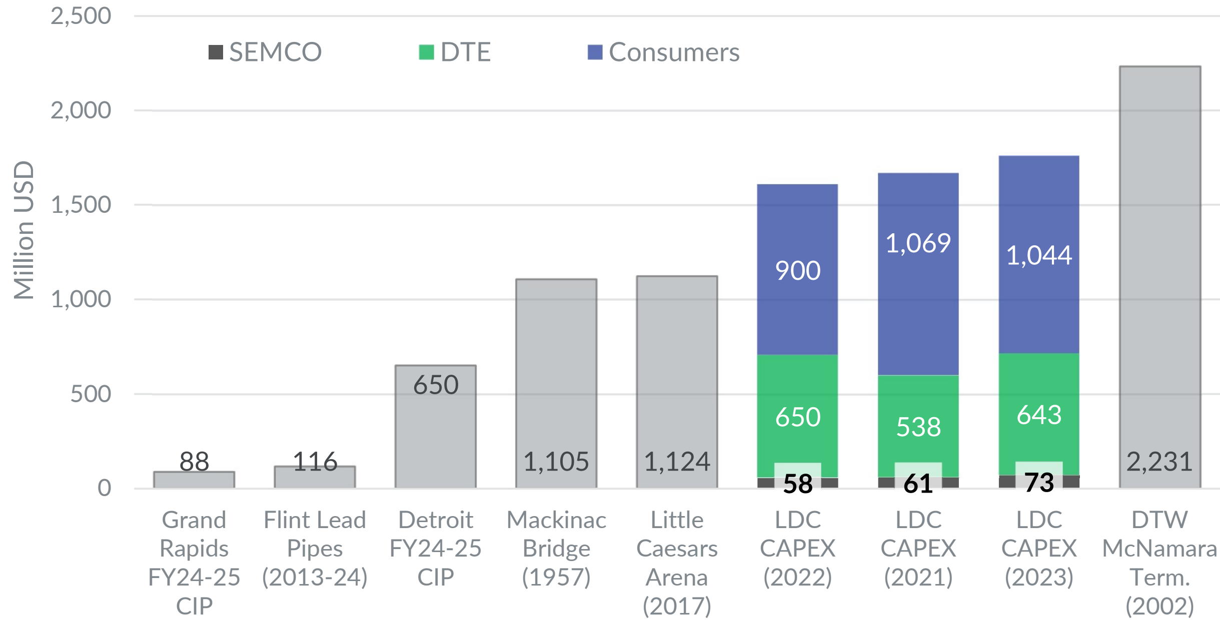
[7] See, for example, the plant-life parameters in DTE's 2023 depreciation study submitted in the U-21384 depreciation case. DTE Exhibit A-6 at pages 25-26.

- **LDC capital expenditures on gas infrastructure are equivalent in scale to once-in-a generation infrastructure projects.** The LDC capital outlays sit right between the inflation adjusted final construction costs of Little Caesars Arena ($862 million in 2017; $1.1 billion in 2024 dollars) and Detroit Metro Airport's Edward H. McNamara Terminal ($1.2 billion in 2002; $2.2 billion in 2024 dollars). The obvious difference is that these projects were seminal, generational projects while LDCs continue to make these levels of expenditures every year.
- **LDC annual expenditures are well above the annual capital expenditures of the state's two largest cities.** According to the five-year capital investment programs (CIPs), the 2024-2025 capital budget for Detroit is $648 million and for Grand Rapids is $88 million. These examples show how more funds are being invested in gas services than any of the public services offered in the state's two largest cities. Detroit's $648 million capital budget for 2024-2025 is roughly equivalent to the $643 million that DTE spent on gas infrastructure in 2023. This means that more is being spent each year on gas infrastructure in Detroit than on water and sewer services, school buildings, and municipal roads.
- **LDC annual expenditures vastly outweigh critical public health infrastructure investments.** The capital program to replace lead service lines and complete investigatory excavations in response to the Flint water crisis has been $97 million ($116 million in 2024 dollars) to date. The fact that the replacement program to address the Flint crisis represents 1/10th of the funds that LDCs invest *every year* should make readers question if the state's limited financial resources for utility infrastructure investments – public and private – are being allocated to address the needs of Michiganders. This topic is again a relevant consideration with the Environmental Protection Agency's (EPA) recent announcement that all lead service lines must be eliminated nationwide by 2034.[8] With an estimated 340,000 lead service lines remaining in Michigan the cost to address this mandate will require upwards of $1.6 billion in capital expenditures. In other words, it will cost about one year's worth of LDC infrastructure spending to eliminate all lead pipes in Michigan.[9] It should also be recognized that the contractors that water service providers will look to hire to address this mandate are inevitably going to be some of the same crews that work on LDC projects, meaning that continued high rates of investment in gas infrastructure could increase the cost and delay compliance with these new regulations.

[8] https://www.washingtonpost.com/climate-solutions/2024/10/08/epa-lead-pipe-removal-rule-drinking-water/

[9] 340,000 lead service lines in Michigan < *https://www.michiganpublic.org/transportation-infrastructure/2024-09-17/new-data-shows-hundreds-of-thousands-of-michiganders-drinking-water-comes-through-a-lead-service-line*> X $4,700 per lead service replacement. <*https://www.brookings.edu/articles/what-would-it-cost-to-replace-all-the-nations-lead-water-pipes/*>

Figure 1.2: Comparison of 2021-2023 LDC Capital Additions to other Michigan Capital Outlays (in millions)



Source: Plant additions compiled from each LDC's annual reports; Detroit and Grand Rapids capital outlays compiled from their respective FY 24-25 CIPs; Mackinac Bridge: *https://www.mackinacbridge.org/ufaqs/much-cost-build-mackinac-bridge/*; Little Caesars Arena: *https://www.detroitnews.com/story/news/local/detroit-city/2017/10/04/little-caesars-arena-financing/106313428/*; McNamara Terminal: *http://www.beiarchitects.com/midfield.html*; Flint pipe replacements: *https://www.cityofflint.com/progress-report-on-flint-water/*.

While LDC investments might not be directly comparable to some of the publicly funded investments in the examples above, the costs of LDC investments are eventually recouped from Michigan's ratepayers through base rates. Therefore, the comparison can be useful in conceptualizing the burden that these plant-in-service expenditures place on the public.

1.2 APPROACH AND OUTLINE OF STUDY

As demonstrated in Section 1.1, the total annual capital additions made by Consumers, DTE, and SEMCO in Michigan have grown by over one billion dollars over the past ten years. This accelerated investment pace impacts the base rates that LDCs charge customers to recover capital costs. Additionally, despite reduced spending in 2020, combined 2023 capital additions being the highest of the decade indicates that capital expenditures by Michigan's three largest utilities are not slowing down. Therefore, projections of base rates are critical to informing decisions related to growing capital investments.

Below the methodology used to develop the base rate projections and the sources of assumptions used in the analysis are described.

Methodology

This study employed a three-step approach to project the potential impact on residential base rates if Michigan's LDCs continue their current capital investment trajectories:

- **Step 1: Capital Investment and Rate Base Projections**. We began by forecasting future capital expenditures for each LDC based on their published investment plans and historical trends. These projections were then used to estimate the annual rate base through 2050. The rate base represents the total value of a utility's capital investments on which it is allowed to earn a return. Components of this step included:
    - Analysis of historical capital addition trends (2011-2023)
    - Review of LDCs' published investment plans
    - Projection of annual capital additions through 2050
    - Calculation of annual depreciation and retirements
    - Estimation of yearly rate base values.
- **Step 2: Revenue requirement projections.** Using the rate base projections, we then calculated the annual revenue requirements. The revenue requirement represents the total amount of revenue a utility needs to collect through base rates to cover its costs and earn its allowed return. Our implementation of this step involved:
    - Calculating return on rate base using approved rates of return
    - Estimating annual depreciation expenses
    - Projecting operation and maintenance expenses
    - Calculating taxes and other allowed expenses
    - Summing up these components to determine the total revenue requirement.
- **Step 3: Rate Impact Calculations.** Finally, we translated the revenue requirements into projected base rates and estimated the impact on typical residential customer bills. This process included:
    - Allocating revenue requirements to customer classes based on recent regulatory decisions
    - Designing rates to collect the allocated revenue from each class
    - Calculating projected monthly bills for typical residential customers
    - Comparing projected bills to historical trends.

We have two notes regarding our methodology and how to interpret the results. First, throughout this analysis, all financial projections are presented in nominal terms (not adjusted for inflation). To allow for a direct comparison between the projections and current values, the figures for capital investments, revenue requirements, and typical bills include trajectories of the most recent historic values increased at the rate of inflation. Second, this analysis focused solely on the base rate component of customer bills and did not account for potential changes in gas commodity costs or other bill components. By following this methodology, we aim to maintain the focus of the results strictly on the impact of capital investments on customer rates over the next several decades without the added uncertainty of gas commodity prices.

Section 2 to Section 4 provide greater detail on the approach taken in this study and present results by LDC.

Assumptions and Source Material

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

- **P-522 annual reports:** These are annual financial and operational reports filed by each utility with the MPSC by April 30th. These reports are publicly available and present standardized information for easy comparison among the LDCs. This study relies on the annual reports 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 filings for the Enhanced Infrastructure Replacement Program (EIRP), Gas Renewal Program (GRP), Main Replacement Program (MRP), or Infrastructure Reliability Improvement Program (IRIP), outline planned capital investments. These filings are useful because of the transparency of disclosing how investments impact final rates. However, the lengthy rate case process means delayed confirmation of which investments are approved for recovery by the Commission. This study relies on the regulatory filings to (i) develop assumptions about what capital investments to include in the revenue requirements, (ii) develop assumptions about the rate design and bill determinants, and (iii) determine historical delivery charges.
- **Presentations made to shareholders:** Quarterly or annual presentations to investor-owned utilities (IOU) shareholders generally include financial results and future investment plans. These presentations often outline the company's medium-term investment goals. However, since they are prepared for the parent companies of utilities, they typically lack detailed information at the individual utility level. We utilized these presentations to form our assumptions about future rate base growth.
- **Inflation Treatment**: All financial projections, including capital expenditure and rate impacts, are presented in nominal terms throughout the study period. The inflation assumptions for future years are discussed further in Section 2.

1.3 ORGANIZATION OF THE REPORT

The remainder of this paper provides the results of the projections and addresses how these results fit into Michigan's current policy and regulatory context. The report is structured as follows:

- Section 2 provides an overview of the approach and assumptions used to forecast future capital additions and presents the results.
- Section 3 presents the revenue requirements needed to pay for projected investments. This section also includes a base rate path through 2050 to recover these revenue requirements and the corresponding bill impacts on a typical customer.
- Section 4 describes how this analysis relates to Michigan's clean energy goals and social inequities in the rate setting process.
- Section 5 concludes the study with a summary of the findings and key takeaways.

SECTION 2 CAPITAL ADDITIONS AND RATE BASE PROJECTIONS

Section 1.1 showed that capital investments by Michigan's three largest LDCs have tripled over the past decade, growing from $578 million in 2013 to $1,739 million in 2023. This rapid increase in capital investments was a major impetus of this study. The objective was to understand the trajectory of base rates if the LDCs continue to invest at the current levels. The crucial first step in this assessment was to begin by developing a forecast for what our expectations of future capital investments will be at each company.

Capital additions represent the new investments made by utilities in their infrastructure each year. These investments form the basis of the utility's rate base – the total value of assets on which the utility is allowed to earn a return. This section begins with an overview of the two approaches we considered using to develop the projections and explains our reasons for taking the prevailing approach. We then provide the results of the capital addition forecasts and corresponding rate base through 2050 for Consumers, DTE, and SEMCO.

2.1 CAPITAL SCENARIOS

To provide a robust and defensible analysis of potential future rate impacts stemming from continued capital investments by Michigan's LDCs, it was crucial to select an appropriate baseline scenario to use for projecting revenue requirements (Section 3) and base rates (Section 4). In developing our projections for capital additions, we considered two approaches to forecasting future investments:

- **CAGR in rate base** - Under a CAGR scenario, annual CAPEX would follow the path needed to maintain a targeted growth rate in rate base. A CAGR scenario is meant to align with a common financial target that IOUs often identify in their investor presentations. For investors, the targets IOUs set for CAGR in rate base serve as a forward-looking indicator of the utility's growth prospects and financial outlook. The "compound" growth means that an increasing level of investment is needed to maintain the same growth rate in rate base year over year. We considered using two possible CAGR scenarios based on two different growth rate targets:
  - **Five-year CAGR in rate base (Scenario 1).** Annual CAPEX follows the path needed to maintain the most recent 5-year trend in CAGR in rate base (2019-2023). This scenario best reflects the current investment trajectory and captures recent trends in the short (1-5 years) to medium (5-10 years) term. But, the long-term (10+ year) investments needed to maintain compound growth could be unrealistically high.
  - **Corporate CAGR in rate base Goals (Scenario 2).** Annual CAPEX follows the path needed to reach any Corporate CAGR rate base targets presented by the IOUs in presentations to shareholders. Recent annual rate base growth targets were identified for Consumers but were not available for DTE or SEMCO. This scenario aligns with common financial performance metric used by IOUs, captures recent trends in the short- and medium-term, and reflects IOUs own performance targets. However, like the option above, the long-term investments needed to maintain compound growth could be unrealistically high.
- **Company investment plans** - This scenario is based on the capital investment plans that utilities have filed with the MPSC. For years beyond the filed plans, we assumed a one percent annual growth in

CAPEX, based on a note in DTE's Gas Delivery Plan indicating that investments will grow on average by one percent per year.

Table 2.1 shows the assumptions by LDC for each of the scenarios. We go into greater detail on the assumptions used in the baseline scenario when presenting the results by LDC in Section 2.2.

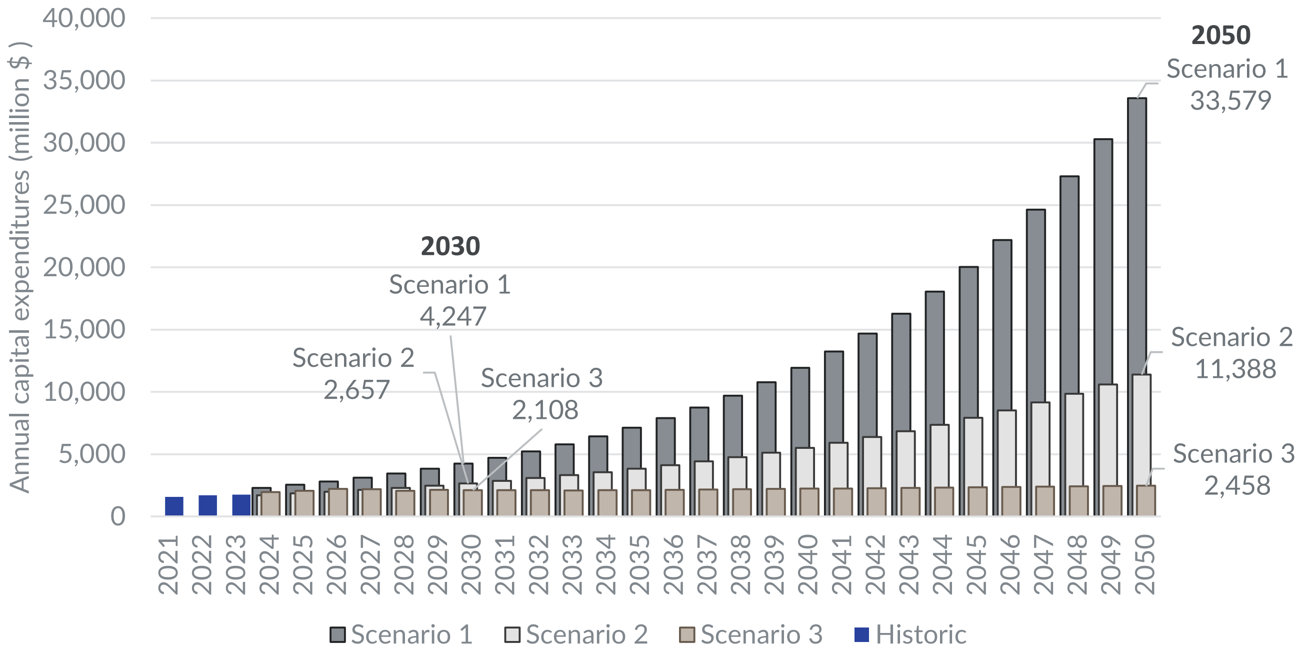
Table 2.1: CAPEX Scenario Assumptions by LDC

	Scenario 1 (Recent Five-year CAGR in rate base)	Scenario 2 (Corporate CAGR In Rate Base Target)	Scenario 3 (Company Investment Plans Submitted to MPSC)
Consumers	11.06% 5-year CAGR in net plant from December 31, 2018 - December 31, 2023	7.5% CMS Energy Corp. annual rate base growth target in September 2024 Investor Presentation[10]	• **2024-2033**: Capital budgets in 2024-2033 Gas Delivery Plan • **2034-2050**: Annual 1% growth in CAPEX
DTE	10.70% 5-year CAGR in net plant from December 31, 2018 - December 31, 2023	N/A	• **2024-2033**: Capital budgets in 2024-2033 Gas Delivery Plan • **2034-2050**: Annual 1% growth in CAPEX
SEMCO	9.76% 5-year CAGR in net plant from December 31, 2018 - December 31, 2023	N/A	• **2024-2027**: MRP and IRIP plans, and other spending estimated based on historical ratio or MRP/IRIP spending to other capital expenditures • **2028-2050**: Annual 1% growth in CAPEX

These three scenarios offer distinct perspectives on potential future investment trajectories: one based on maintaining current investment trends; one based on corporate investment goals; and another based on specific investment plans submitted to MPSC. Figure 2.1 below shows how the sum of the annual investment forecasts for the three LDCs compare under each scenario.

[10]CMS Energy. "Investor Meetings: September 2024" CMS Energy quarterly investor presentation. 3 September 2024. <*https://s26.q4cdn.com/888045447/files/doc_presentations/2024/09/September-2024-Presentation.pdf*>

Figure 2.1: LDC's Total Investments for 2025-2050 by Scenario



The scenarios are relatively close in 2030 and then rapidly separate through 2050. For reference, the sum of pairwise differences between scenarios increases from $4,300 million in 2030 to $62,200 million in 2050.[11] The concerns raised above about the potential inaccuracy of compound growth are certainly evident in Scenario 1 where the combined investments of the utilities would top $33,579 million in 2050 – $31,121 million more than the $2,458 million under Scenario 3. While the Scenario 1 result seems unlikely, it is important to recognize this pathway represents the pathway the LDCs are on based on their actual investments over the last five years.

After consideration of the three scenarios, we selected Scenario 3 (Company Investment Plans) as the baseline scenario for this analysis. This decision was based on the following factors:

1) **Regulatory Alignment**: Scenario 3 is directly tied to the investment plans that utilities have filed with the MPSC. This alignment with official regulatory filings provides a solid foundation for our projections.

2) **Conservative Estimate**: While the CAGR scenarios (1 and 2) might lead to higher long-term projections due to compounding effects, Scenario 3 offers a more conservative estimate of future investments. For years beyond the filed plans, we assumed a modest one percent annual growth in CAPEX. This approach helps prevent potential overestimation of rate impacts.

3) **Defensibility**: Using the utilities' own filed plans as a basis for our projections makes our analysis more defensible against potential criticism from the utilities or other stakeholders.

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[11] The sum of pairwise differences is a measure that quantifies the total spread or dispersion within a set of numbers by adding up the absolute differences between all possible pairs of values in the set.

4) **Transparency**: Scenario 3 allows for clear traceability between our projections and the utilities' publicly stated intentions, enhancing the transparency of our analysis.

While Scenarios 1 and 2 offer valuable insights into potential investment trajectories based on historical trends and corporate targets, we believe Scenario 3 provides the most grounded and defensible basis for projecting future capital additions and their potential impact on rates. However, it's important to note that actual future investments may differ based on changing regulatory, economic, or strategic factors.

2.2 COMPANY CAPEX FORECASTS

The following subsections describe the historic and projected capital investments for Consumers (Section 2.2.1), DTE (Section 2.2.2), and SEMCO (Section 2.2.3).

What appear for each company are our projections for the *annual capital expenditure* or the cash-outlays on capital investments each year. As will be explained more in Section 3, expenditures are reflected in rate base as either utility plant-in-service (UPIS) or Capital Work in Progress (CWIP).

- **UPIS** refers to utility assets that are completed and actively used in providing service to customers. Depreciation only begins to accrue once plant is completed and placed into service. When plant is included as UPIS in rate base, both a *return on investment* (rate of return on undepreciated value) and a *return of investment* (annual depreciation expenses) are reflected in the revenue requirement.
- **CWIP** represents ongoing construction or development projects that are not yet completed or operational. Regulatory treatment of CWIP varies. Some regulators allow CWIP in rate base, letting utilities earn *returns on* investments before completion, which can reduce financing costs. Others use "AFUDC" (Allowance for Funds Used During Construction), where utilities are allowed to accrue financing costs at the approved rate of return until the plant is placed into service. AFUDC can lead to higher long-term costs for customers due to its compounding effect, as ratepayers essentially pay interest on interest over the asset's lifetime. This study uses the CWIP in rate base approach because that is what MPSC allows.

The capital expenditure values for historic years presented in this section are calculated as the annual plant additions plus the net change in CWIP (end of year CWIP – start of year CWIP).

It should also be reiterated, as first explained in sections on the study methodology and assumptions (Section 1.2), that we are presenting these capital expenditure projections in nominal terms.[12] To provide a basis of comparison we include lines representing what the 2011 and 2023 expenditure levels would be if grown at the rate of actual/projected inflation.[13]

2.2.1 CONSUMERS

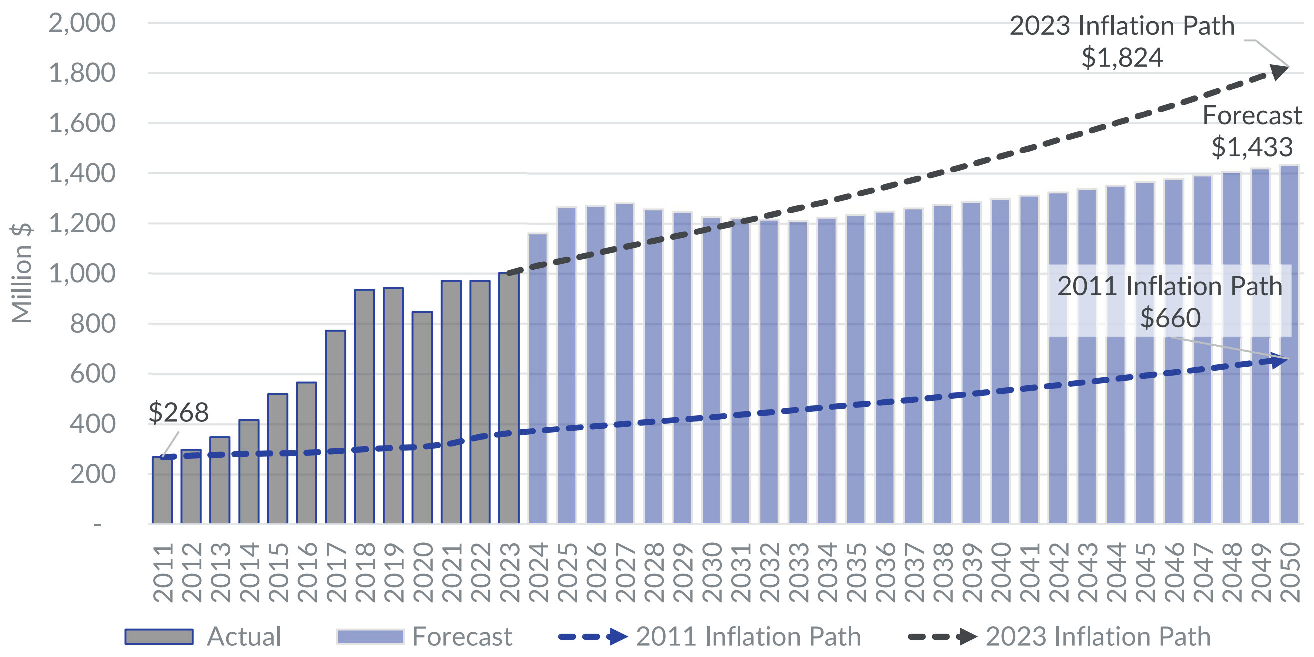
Figure 2.2 shows historical capital expenditures made by Consumers from 2011 to 2023, followed by projected expenditures from 2024 to 2050. Historical data demonstrate a clear upward trend, with capital

[12] This assumes that company investment plans include some budget adjustment to account for inflation.
[13] Inflation adjustments are made using the urban consumer price index (CPI-U) as a deflator. The annual average CPI-U published by the Bureau of Labor and Statistics (BLS) is used for 2012 through 2024. Congressional Budget Office (CBO) projections for the CPI-U from *January 2025* are used for 2025-2035 and then the CPI-U is assumed to grow at CBO's 2035 annual growth rate (2.3%) from 2036 through 2050.

additions increasing from $268 million in 2011 to $1,002 million in 2023, representing an 11.6 percent average annual increase in spending over this 12-year period.

The projections for Consumers' capital expenditures are based on the company's investment plans (Scenario 3). For the period 2024 to 2033, we used the Natural Gas Delivery Plan (NGDP) submitted to the MPSC in Case No. U-21439. This plan outlines approximately $1,230 million in capital expenditure over the ten-year period. For the years 2034 to 2050, we projected a one percent year-over-year growth in annual capital expenditures. As shown in Figure 2.2, this results in future capital additions (blue bars) increasing from $1,002 million in 2023 to over $1,400 million by 2050. Over the 26-year projection period from 2024 to 2050, we estimate expenditures of $34,869 million from 2024 to 2050.

Figure 2.2: Consumers' Historical and Projected Capital Additions



Source: Consumer's Form P-522 for Years 2010-2023.

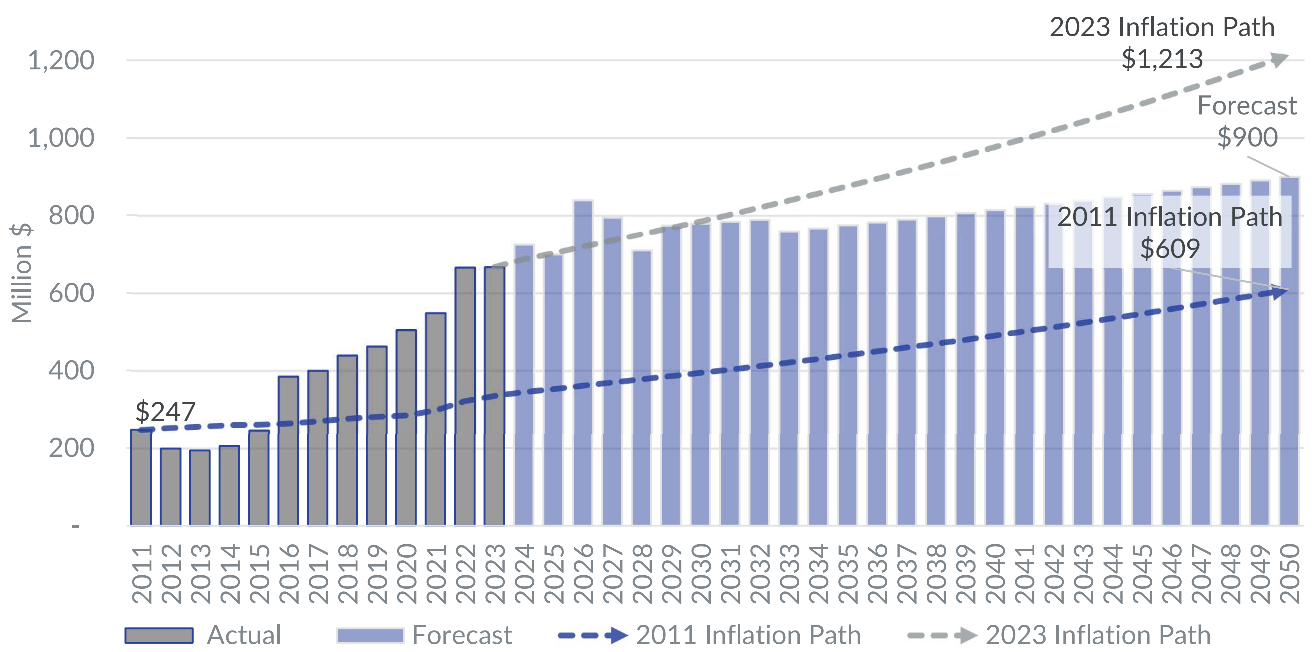
For reference, Figure 2.2 also includes alternative investment pathways of what capital expenditures will be (or would have been) if the company sustained investments at either the 2011 (dark blue dashed line) or 2023 (gray dashed line) levels adjusted for inflation. These lines establish helpful points of comparison to use when considering the investment path used for Consumers in this study. If Consumers were only to grow 2023 expenditure levels at the rate of inflation, the result in 2050 ($1,824 million) would be $391 million greater (+27%) than this study's projected 2050 expenditures. This not only demonstrates that our projections are conservative but also reinforces the concerns raised in this study about current spending levels. The 2011 inflation adjusted pathway helps drive this point home by acting as the floor for what investment levels were before the recent rise in expenditures. The fact that in 2050 the inflation trajectory of the 2023 spend levels are three times the inflation trajectory of the 2011 investments ($660 million) underscores the rapid rise in capital expenditures since 2011.

2.2.2 DTE

Figure 2.3 shows DTE's historical capital expenditure from 2011 to 2023, followed by projected expenditures from 2024 to 2050. Historical data demonstrate a clear upward trend, with capital additions increasing from $161 million in 2011 to $667 million in 2023, representing a 12.6 percent average annual increase in spending over this 12-year period.

DTE's capital expenditure projections also follow the company investment plans approach (Scenario 3). The 2024 to 2033 projections are derived from DTE's NGDP submitted to the MPSC in Case No. U-21291. This plan includes approximately $7.7 billion in capital expenditure over the ten-year period. For 2034 to 2050, we applied a one percent year-over-year growth rate to the annual capital expenditures. As illustrated in Figure 2.3, this projection shows capital additions rising from $667 million in 2023 to about $900 million by 2050. Over the 26-year projection period from 2024 to 2050, we estimate expenditures of $21,807 million from 2024 to 2050.

Figure 2.3: DTE's Historical and Projected Capital Additions



Source: DTE's Form P-522 for Years 2010-2023.

The alternative investment pathways in Figure 2.3 also indicate what capital expenditures will be (or would have been) if DTE sustained investments at either the 2011 (dark blue dashed line) or 2023 (gray dashed line) levels adjusted for inflation.[14] Like Consumers, these lines establish points of comparison to use when considering the projected investment path. If DTE were only to grow 2023 expenditures at the rate of inflation the result in 2050 ($1,213 million) would actually be $313 million *greater* (+35%) than this study's projected 2050 expenditures. Again, this result demonstrates that our projections are on the conservative

[14] Inflation adjustments are made using the urban consumer price index (CPI-U) as a deflator. The annual average CPI-U published by the Bureau of Labor and Statistics (BLS) is used for 2012 through 2024. Congressional Budget Office (CBO) projections for the CPI-U from [January 2025] are used for 2025-2035 and then the CPI-U is assumed to grow at CBO's 2035 annual growth rate (2.3%) from 2036 through 2050.

side and underscores the heightened level of current capital expenditures. The 2011 inflation trajectory for DTE also demonstrates the rapid rise in capital expenditures and how their expenditures are projected to continue to rise. The inflation trajectory of 2011 expenditures in 2050 ($609 million) is 32 percent below our projected 2050 spend and 50 percent below the inflation trajectory of 2023 expenditures.

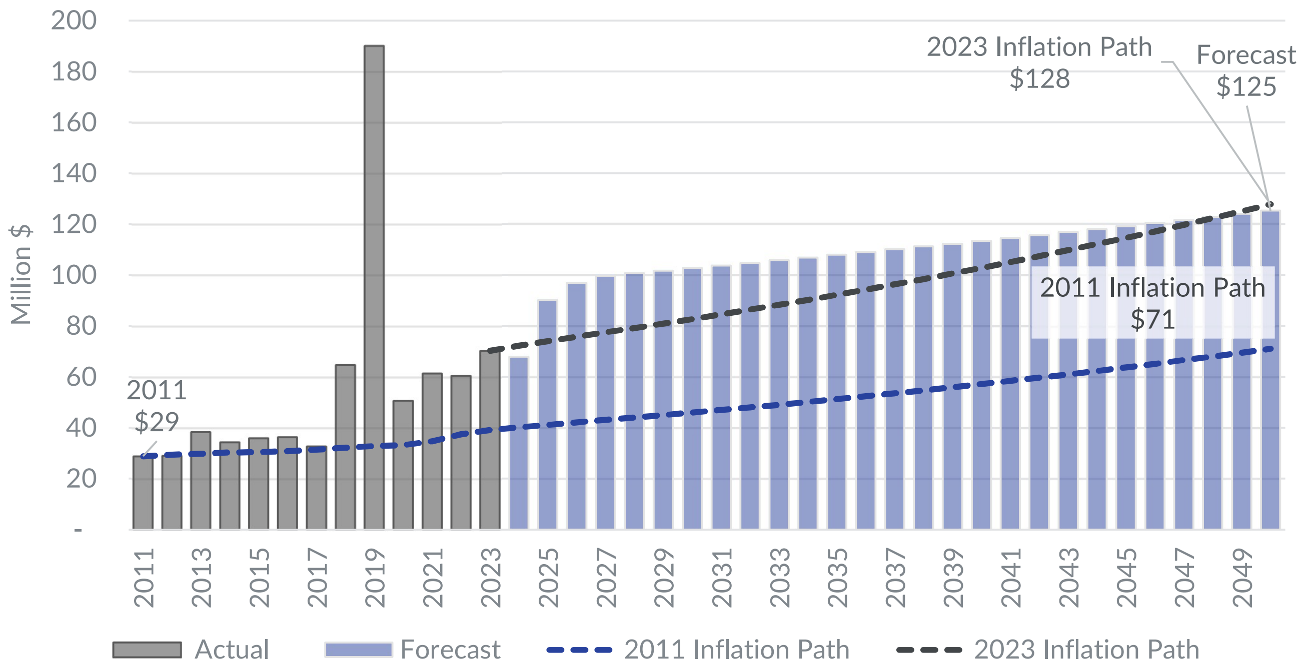
2.2.3 SEMCO

Figure 2.4 shows SEMCO's capital additions for 2011-2023. These capital additions have an overall upward trend, with small dips in several years and one large increase in 2019. The outlier in 2019 can be attributed to the Marquette Connector, a 42.6-mile, $159 million transmission project, the majority of which was placed into service in 2019.[15] Over the past 12 years, capital additions have increased by $43 million (from $27 million in 2011 to $70 million in 2023). This amounts to a CAGR of 8.3 percent in spending from 2011 to 2023.

SEMCO capital expenditure projections also use the company investment plans approach (Scenario 3), although the assumptions are different because SEMCO does not have a comprehensive gas delivery plan like Consumers and DTE. For 2024-2027, we used SEMCO's MRP and IRIP plans, which include $141.8 million in capital expenditures. Based on historical data from 2021 to 2023, where MRP and IRIP represented about 38 percent of total capital expenditures, we estimated total capital expenditures by multiplying the annual MRP and IRIP budgets by 2.63. For 2028-2050, we projected a one percent year-over-year growth in annual capital expenditures. As shown in Figure 2.4, this results in capital additions increasing from $70 million in 2023 to approximately $125 million by 2050. Over the 26-year projection period from 2024 to 2050, we estimate expenditures of over $2,942 million from 2024 to 2050.

[15] Case No. U-20479, Testimony of Daniel J. Forsyth, p.5.; SEMCO 2019 Annual Report

Figure 2.4: SEMCO's Historical and Projected Capital Additions



Source: SEMCO's Form P-522 for Years 2010-2023.

Figure 2.4 also shows what the alternative investment pathways for SEMCO's capital expenditures will be if the company sustains investments at either the 2011 (dark blue dashed line) or 2023 (gray dashed line) levels adjusted for inflation.[16] For SEMCO, these lines provide a basis of comparison when considering the investment path used for Consumers in this study. If Consumers were only to grow 2023 expenditures at the rate of inflation, the result in 2050 ($1,824 million) would be $391 million greater (+27%) than this study's projected 2050 expenditures. This not only demonstrates that our projections are conservative but also reinforces that current levels are extremely high. The 2011 inflation adjusted pathway helps drive this point home by acting as the baseline for what investment levels were before the recent rise in expenditures.

[16] Inflation adjustments are made using the urban consumer price index (CPI-U) as a deflator. The annual average CPI-U published by the Bureau of Labor and Statistics (BLS) is used for 2012 through 2024. Congressional Budget Office (CBO) projections for the CPI-U from *January 2025* are used for 2025-2035 and then the CPI-U is assumed to grow at CBO's 2035 annual growth rate (2.3%) from 2036 through 2050.

SECTION 3 FUTURE REVENUE REQUIREMENTS

This section presents projections of the revenue requirements needed to recover the cost of the forecasted capital additions described in Section 2. The revenue requirement is the total amount of revenue a utility needs to collect through rates to cover its operating costs, taxes, depreciation, and provide a fair return on its investments. It represents the utility's cost of service and is a key component in determining the rates customers pay. In this study, we project future revenue requirements to understand the potential impact of planned capital investments on customer rates. For this purpose, costs are grouped into two categories:

- **Capital-related costs** include any cost component directly impacted by changes in utility plant in service. This includes depreciation, return on rate base, and property taxes.
- **Operating costs** include all other utility operating costs (excluding gas commodity costs).

A Microsoft Excel-based revenue requirement model was used to estimate the capital-related components of the annual revenue requirement based on the outputs of the capital investment projections. These components include return on rate base, depreciation, and property taxes.

The annual revenue requirement projections use assumptions based on a combination of the recent rate case filings and decisions, depreciation case decisions, and annual reports. Table 3.1 shows these assumptions for each LDC.

Table 3.1: CAPEX Revenue Requirement Assumptions

	Consumers	DTE	SEMCO
Depreciation rate (weighted average)	2.53%	2.79%	2.88%
Retirement rate (% of plant in service at the start of the year)	0.64%	0.89%	0.84%
Weighted average cost of capital (pre-tax)	8.77%	8.78%	9.43%
Effective property tax rate (% of start of year plant in service)	1.39%	1.17%	1.29%

Sources: Depreciation rates are composite rates for all plant from each company's most recent depreciation case; Retirement rates are based on the average retirement rate in 2018 to 2023 in annual reports. Rate of return / cost of capital are the rates approved in each company's most recently completed based rate case. Property tax rates were calculated from the test year data submitted in the most recent base rate case filings, including ongoing cases.

Assumptions for the level of operating costs to be included in the annual revenue requirements were based on other operating expenses and taxes included in 2023 annual reports. The 2023 amounts were converted into 2024 dollars using the urban consumer price index (CPI-U) as a deflator. For future years, the Congressional Budget Office (CBO) projections for the CPI-U from January 2025 are used to make inflation adjustments for 2025 to 2035 and then the CPI-U is assumed to grow at CBO's 2035 annual growth rate (2.3%) from 2036 through 2050. Table 3.2 shows the assumptions for operating costs for each company that are used for the entire projection period in 2024 dollars.

Table 3.2: OPEX Revenue Requirement Assumptions, (2024 dollars)

	Consumers	DTE	SEMCO
Non-gas O&M expenses	440,906,211	445,787,271	65,765,138
Federal payroll taxes	13,504,743	45,750,878	7,248,655
State payroll and other non-property local taxes	5,783,933	2,620,801	1,535,490
Other operating expenses	460,194,887	494,158,950	74,549,283

Sources: Form P-522 Annual Report (2023). Other operating expenses calculated as O&M – cost of gas + other local and federal taxes in P-522.

The results of the revenue requirement models for each LDC are described in Section 3.1 (Consumers), Section 3.2 (DTE), and Section 3.3 (SEMCO).

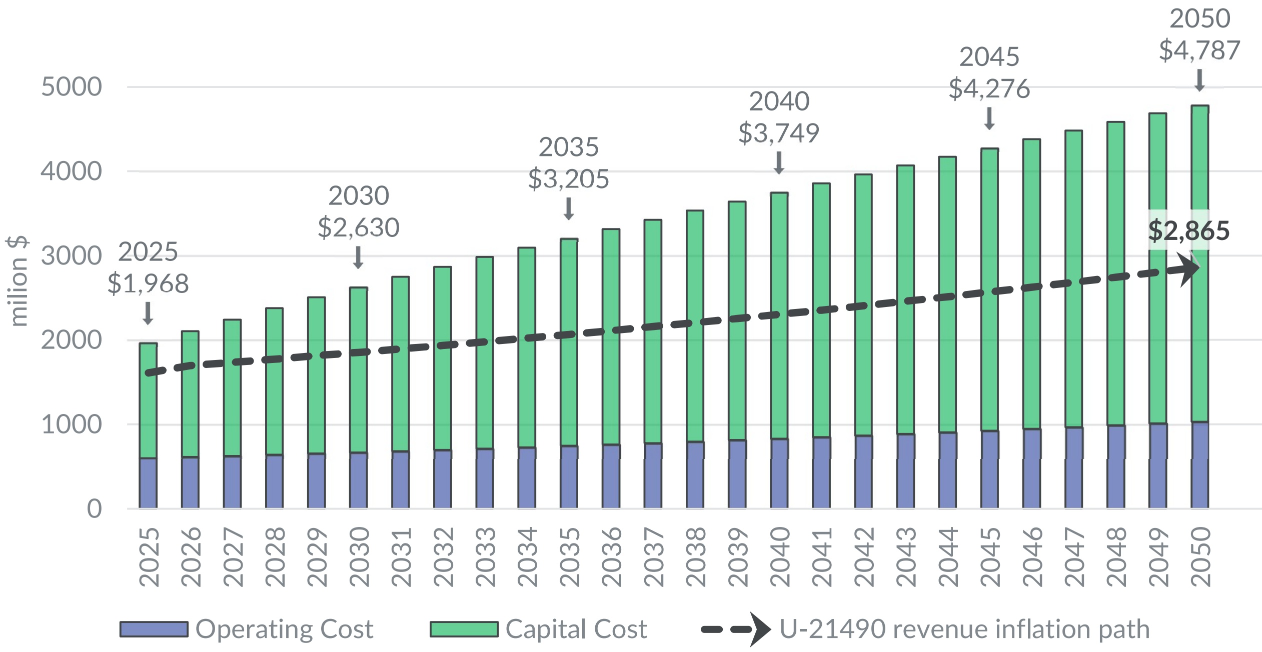
3.1 CONSUMERS

Figure 3.1 shows Consumers' projected revenue requirements for 2025-2050. The projected revenue requirement increases from $1,968 million in 2025 to $4,786 million in 2050. For reference, Consumers' current approved revenue requirement from U-21490 (July 2024) is around $1,574 million.[17] The projected 2050 revenue requirement is $1,921 million (67 percent) greater than the trajectory of what the U-21490 revenue requirement grown at the rate of forecasted inflation would be in 2050 ($2,865 million).

Under this projected scenario, customers would be asked to pay a total of $68,922 million between 2025 and 2050 to cover capital costs alone. Of that amount, 64 percent or $44,374 million would be payments toward the new investments made starting in 2025.

[17] This amount represents the sum of the revenue reflected in the approved base revenue in the U-21490 settlement agreement and the adjusted other revenues presented by the Company in its initial filing: $1,574 million = $1,546 million in total base revenue (U-21490 Order, Att. 2) + $28 million other utility revenue (U-21490, Exhibit A-13).

Figure 3.1: Consumers Revenue Requirements, 2025–2050



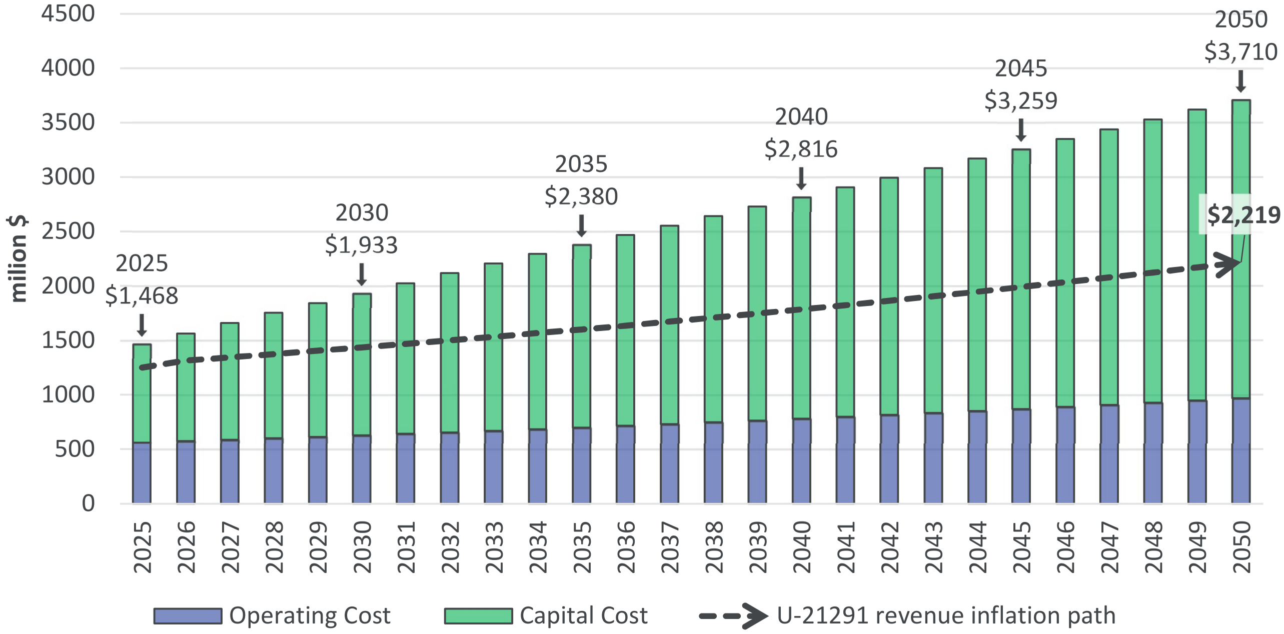
Source: Consultant projections.

3.2 DTE

Figure 3.2 shows DTE's projected revenue requirements for 2024-2050. The revenue requirement to collect from customers through base rates is projected to increase from $1,468 million in 2025 to $3,710 million in 2050. For reference, DTE's current approved revenue requirement from U-21291 (November 2024) is around $1,574 million.[18] Under this projected scenario, customers would be asked to pay a total of $48,051 million between 2025 and 2050 to cover capital costs. Of that amount, 61 percent or $29,469 million would be payments toward the new investments made after 2024.

[18] $1,574 million = $1,086 million in base revenue (U-21291 Order, Att. A) + $16.80 million in IRM revenue + $116 million other utility revenue (U-21291, Exhibit A-13).

Figure 3.2: DTE Revenue Requirements, 2025–2050



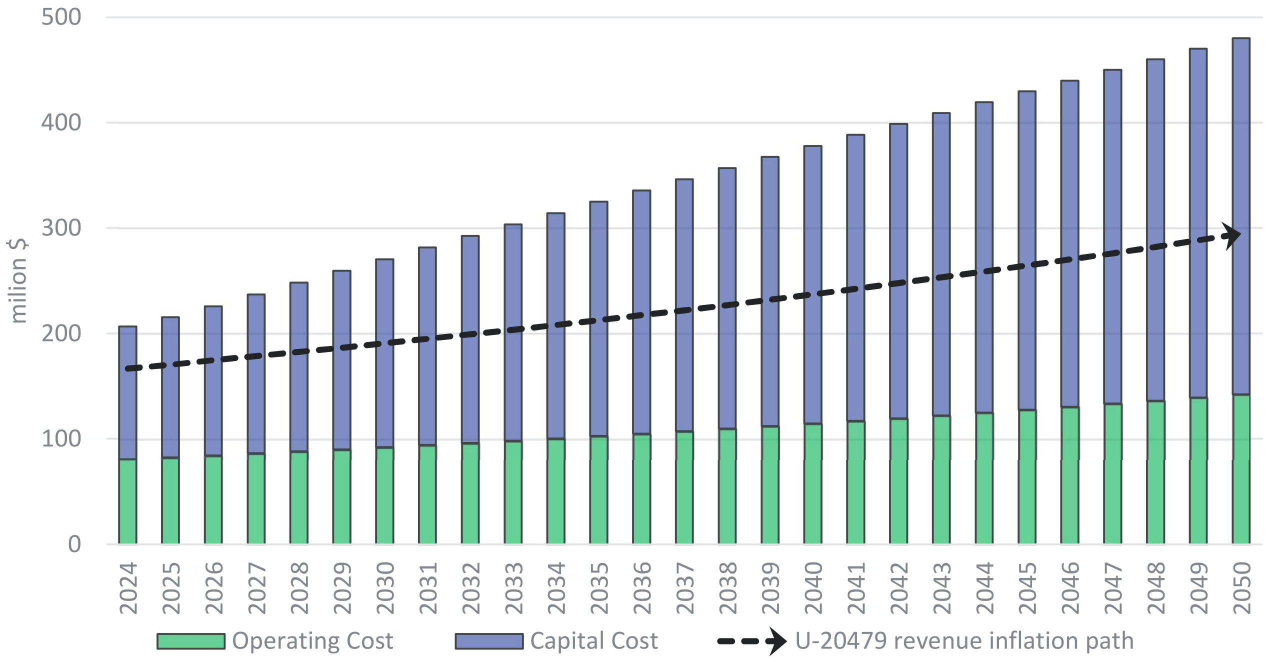
Source: Consultant projections.

3.3 SEMCO

Figure 3.3 shows SEMCO's projected revenue requirements for 2024-2050. The revenue requirement increases from $206 million in 2024 to $480 million in 2050. This represents a $186 million (63%) increase in revenue compared to the $294 million in projected revenue if the $1,629 million revenue approved in SEMCO's 2019 base rate case (U-20479) simply grew at the rate of inflation.[19] Under the projected scenario, customers would be asked to pay a total of $6,243 million between 2025 and 2050 to cover capital costs. Of that amount, 64 percent or $3,976 million would be payments toward the new investments made after 2024.

[19] $162.1 million = $292.2 million in total revenue - $142.2 million in gas commodity sales + $12.2 million in other utility revenue

Figure 3.3: SEMCO Revenue Requirements, 2025–2050



Source: Consultant projections.

SECTION 4 RATE IMPACTS

This section details the rate impacts (i.e., estimated customer bills) resulting from the projected revenue requirements described in Section 3.

Revenue requirements were allocated among the different rate classes served by each LDC (using the allocation factor). Base rates were then designed to collect that level of revenue from each customer class (using bill determinants). Fixed rates grew at a rate reflecting the growth in fixed charges over the past ten years, and any remaining incremental costs were added to the volumetric rate.

Bill determinants are the specific units of measurement used to calculate a customer's bill. For gas utilities, these typically include the number of customers (for fixed charges) and the volume of gas consumed (for volumetric charges). In this analysis, we use residential customer-months for fixed charges and annual sales volumes (in Mcf or Dth) for volumetric charges. These determinants, combined with the revenue requirement, allow us to project future rates and bill impacts. Table 4.1 lists assumptions for residential class cost allocation factors and other billing determinants, based on recent general rate case filings for each company.

Table 4.1: Rate Design and Bill Determinant Assumptions

	Consumers	DTE	SEMCO
Residential revenue allocation %	71.94%	62.79%	66.61%
Residential customer-months	20,494,128	14,908,548	3,391,116
Sales	158,217,664 Mcf	112,464,000 Mcf	26,985,347 Dth
Starting fixed charge	$15.00	$13.50	$12.25
Growth rate of fixed charges (%/year)	2.58%	2.27%	0.45%
Gas commodity charge	$3.61/Mcf	$4.62/Dth	$4.62/Dth

Source: Allocation factors, sales, and starting fixed charges are from U-21308, U-20940, and U-20479; residential customer-months are from U-21490 - Exhibit E-5, U-21291 - Exhibit E-5, and U-20479 - Exhibit E-5; growth rates of fixed charges are calculated (2011-2025 growth rates).

Gas bills in Michigan currently include other surcharges, such as DTE's Infrastructure Renewal Mechanism (IRM) and SEMCO's MRP and IRIP surcharges, which allow utilities to reconcile or recover some capital costs incurred between base rate adjustments. We assume all capital tracker mechanisms are set to zero during the forecast period and that these costs are recovered through base rates. We do not include any other surcharge mechanisms in the analysis (e.g., energy efficiency charges or revenue decoupling mechanisms), as the purpose of the analysis is to isolate the effect of capital investments on base rates.

Projected volumetric charges for residential customers from 2024 to 2050 and estimated monthly residential base rate bills based on average monthly consumption are presented in Section 4.1 (Consumers), Section 4.2 (DTE), and Section 4.3 (SEMCO).

4.1 CONSUMERS

Table 4.2 shows Consumers' base volumetric charge (i.e., the base delivery charge) calculations for 2026. The base volumetric charge relies on the revenue requirement projections and the allocation factor and bill determinants from Table 4.1. This process was repeated each year from 2027 through 2050.

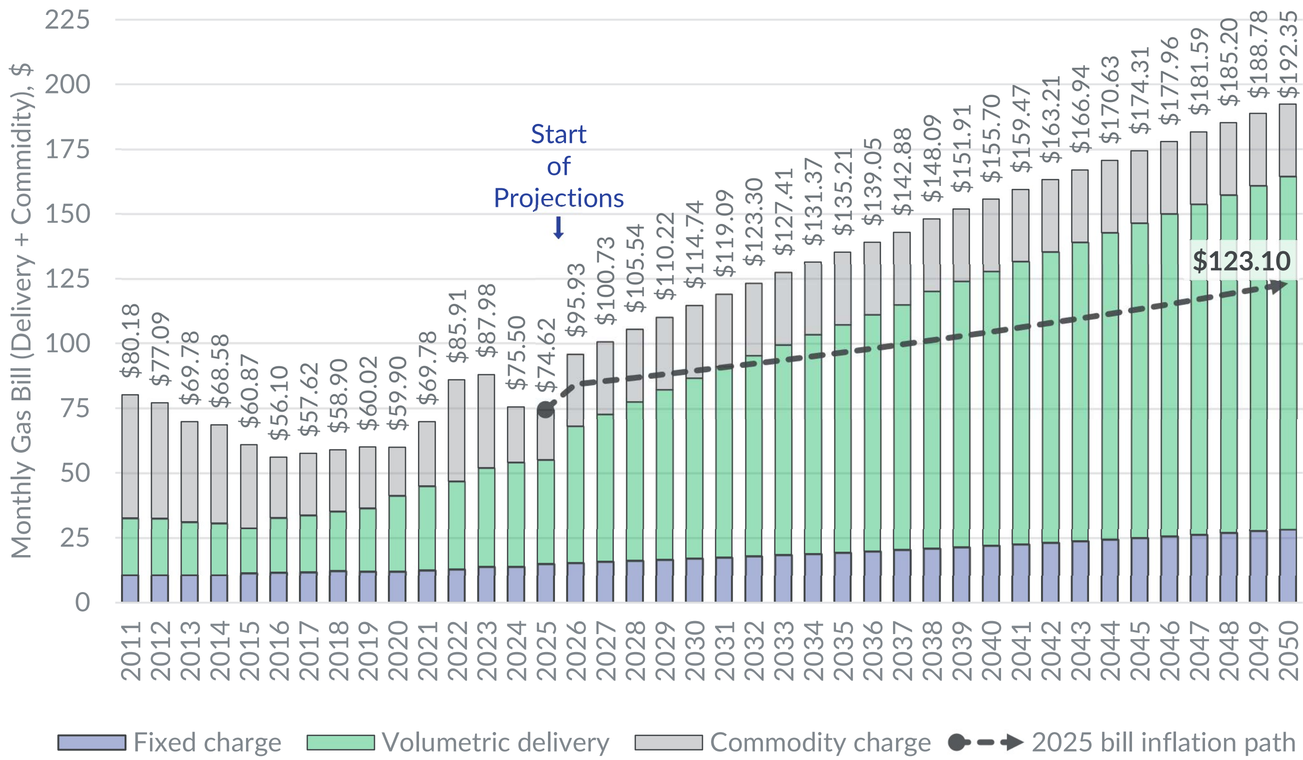
Table 4.2: Consumers Projected Volumetric Rate Calculation, 2025

#	Item	Note	2026
1	Revenue Requirement (million)		$2,075.54
2	Residential Allocation Factor		71.94%
3	Residential Revenue Requirement Allocation (million)	Line 1 x Line 2	$1,493.10
4	Monthly Fixed Charge		$15.78
5	Residential Bills		20,494,128
6	Fixed Revenues (million)	Line 4 x Line 5	$323.48
7	Volumetric Revenue (million)	Line 3 – Line 6	1,169.61
8	Volumetric Deliveries (Mcf)		158,217,664
9	Base Volumetric Charge	Line 7 / Line 8	$7.5433

Figure 4.1 shows historical (2011-2025) and projected (2026-2050) typical monthly delivery charges for Consumers' residential customers (i.e., the fixed monthly charge and the base volumetric delivery charge). These charges are based on average monthly residential natural gas consumption for Consumers' customers (7.72 MMcf).[20] A typical Consumers' residential bill is projected to increase $113.50 from $74.62 in 2025 to $192.35 in 2050 (a 158 percent increase overall, or 3.86 percent per year). If base rates instead only grew at the rate of projected inflation, the 2050 bill would be $123.10 – $69.25, or 36 percent lower than our projections.

[20] Historical rates shown are based on final rates (ignoring any interim rates) approved by the MPSC and include the monthly fixed charge (base, IRM, RDM, and VRM), volumetric delivery charge, and commodity charge. 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 4.2), keep the monthly customer charge constant from their latest approved final value, and assume IRM, RDM, and VRM are set to zero (with their costs recovered in base rates instead).

Figure 4.1: Consumers Typical Residential Monthly Bill Projections, 2011–2050



Sources: Historical delivery charges from MPSC's natural gas rate history document < https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/nat-gas/gasrates.pdf >. Projected delivery charges are consultant projections.

4.2 DTE

Table 4.3 shows DTE's base volumetric charge (i.e., the base delivery charge) calculations for 2026. The base volumetric charge relies on the revenue requirement projections, as well as the allocation factor and bill determinants from Table 4.3. This process was repeated each year from 2027 through 2050.

Table 4.3: DTE Typical Residential Monthly Bill Projections, 2011–2050

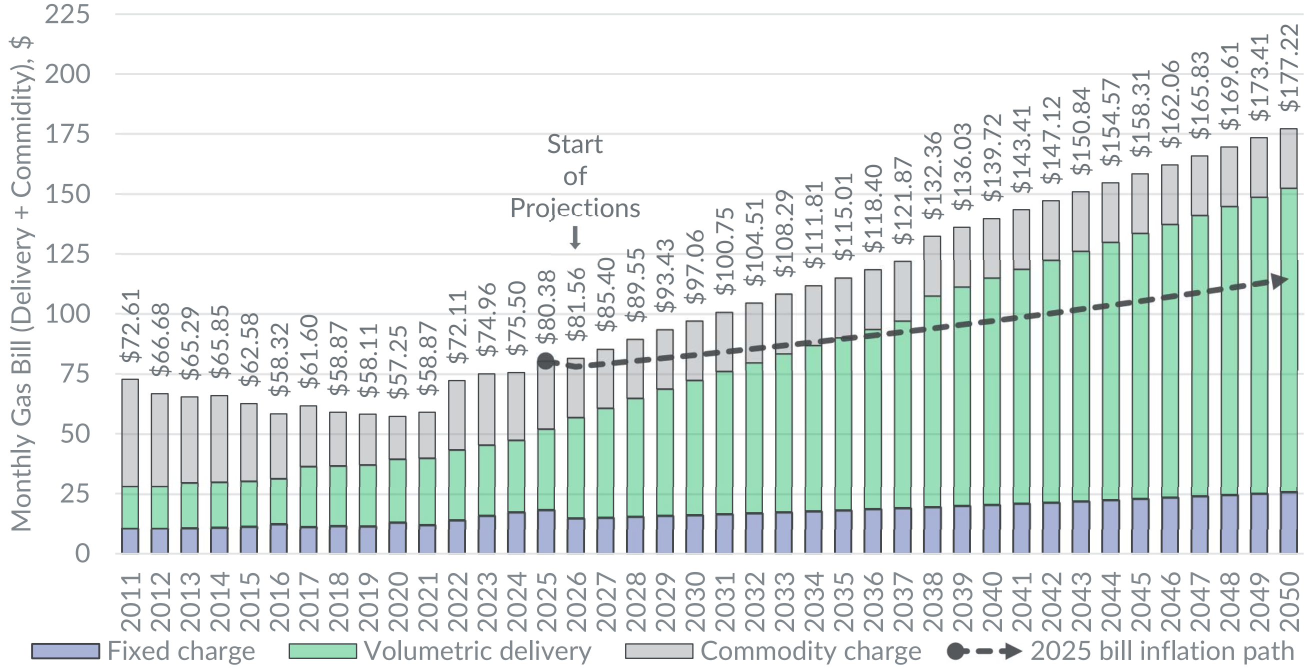
#	Item	Note	2025
1	Revenue Requirement (million)		$1,341.24
2	Residential Allocation Factor		62.79%
3	Residential Revenue Requirement Allocation (million)	Line 1 x Line 2	$842.20
4	Monthly Fixed Charge		$13.81
5	Residential Bills		14,908,548
6	Fixed Revenues (million)	Line 4 x Line 5	$205.83
7	Volumetric Revenue (million)	Line 3 – Line 6	$636.36
8	Volumetric Deliveries (Mcf)		112,464,000
9	Base Volumetric Charge	Line 7 / Line 8	$5.6584

Figure 4.2 shows historical (2011-2025) and projected (2026-2050) typical monthly delivery charges for DTE's residential customers (i.e., the fixed monthly charge and the base volumetric delivery charge). These charges are based on average monthly residential natural gas consumption for DTE's customers (7.54 Mcf).[21]

[21] Historical rates shown are based on final rates (ignoring any interim rates) approved by the MPSC and include the monthly fixed charge (base, IRM, and RDM), volumetric delivery charge, and commodity charge. Weighted averages are used whenever any rate or rider changes

A typical DTE residential customer bill is projected to increase $96.84 from $80.37 in 2025 to $177.22 in 2050 (a 120 percent increase overall, or 3.2 percent per year). If base rates instead only grew at the rate of projected inflation, the 2050 bill would be $114.55 – $62.67, or 35 percent lower than our projections.

Figure 4.2: DTE Typical Residential Monthly Bill Projections, 2011–2050



Sources: Historical delivery charges from MPSC's natural gas rate history document < https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/nat-gas/gasrates.pdf>. Projected delivery charges are consultant projections.

4.3 SEMCO

Table 4.4 shows SEMCO's base volumetric charge (i.e., the base delivery charge) calculations for 2025. The base volumetric charge relies on the revenue requirement projections and the allocation factor and bill determinants from Table 4.4. This process was repeated each year from 2026 through 2050.

Table 4.4: SEMCO Rate Calculation Example (2026)

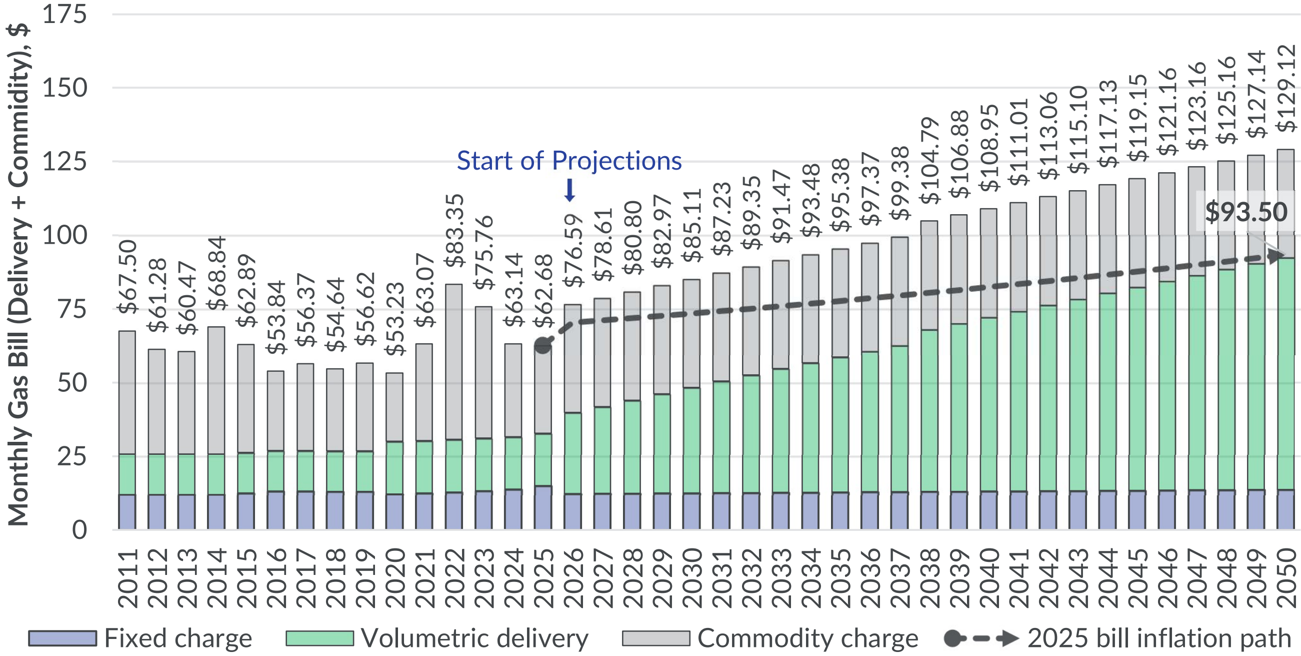
#	Item	Note	2025
1	Revenue Requirement (million)		$200.71
2	Residential Allocation Factor		66.61%
3	Residential Revenue Requirement Allocation (million)	Line 1 x Line 2	$133.70
4	Monthly Fixed Charge		$12.31
5	Residential Bills		3,391,116
6	Fixed Revenues (million)	Line 4 x Line 5	$ 41.74
7	Volumetric Revenue (million)	Line 3 – Line 6	$91.95
8	Residential Therms		26,985,347
9	Base Volumetric Charge	Line 7 / Line 8	$3.4076

Figure 4.3 shows historical (2011-2025) and projected (2026-2050) typical monthly delivery charges for SEMCO's residential customers (i.e., the fixed monthly charge and the base volumetric delivery charge). These

within a calendar year. Projected rates use our projected base volumetric rates (as calculated for each year as shown in Table 4.2), keep the monthly customer charge constant from their latest approved final value, and assume IRM and RDM are set to zero (with their costs recovered in base rates instead).

charges are based on average monthly residential natural gas consumption for SEMCO's customers (7.96 Dth).[22] A typical SEMCO residential customer's bill is projected to increase $52.26 from $62.68 in 2025 to $129.13 in 2050 (a 106 percent increase overall, or 2.93 percent per year). If base rates instead only grew at the rate of projected inflation, the 2050 bill would be $93.50 – $35.62, or 28 percent lower than our projections.

Figure 4.3: SEMCO Typical Residential Monthly Bill Projections, 2011–2050



Sources: Historical delivery charges from MPSC's natural gas rate history document < https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/nat-gas/gasrates.pdf>. Projected delivery charges are consultant projections.

[22] Historical rates shown are based on final rates approved by the MPSC and include the monthly fixed charge (base, IRM, RDM, and TCJA), volumetric delivery charge, and commodity charge. 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 4.2), keep the monthly customer charge constant from their latest approved final value, and assume IRM, RDM, and TCJA are set to zero (with their costs recovered in base rates instead).

SECTION 5 THE FUTURE OF NATURAL GAS IN MICHIGAN

This report has examined several interconnected factors facing Michigan's energy landscape: the LDCs' accelerated investment in natural gas infrastructure, the state's commitment to emissions reductions, and considerations of equity and affordability in utility rates. The following subsections elaborate on the intersection of these factors and what they mean for Michigan's energy future.

5.1 MICHIGAN'S CLIMATE GOALS AND NATURAL GAS EMISSIONS

Michigan has established increasingly ambitious targets for reducing greenhouse gas (GHG) emissions through multiple policy mechanisms. As part of its entry into the US Climate Alliance, Michigan pledged through Executive Directive 2019-12 to reduce emissions to 26-28 percent below 2005 baseline levels by 2025. The 2022 MI Healthy Climate Plan expanded on this commitment, establishing a pathway for Michigan to achieve complete carbon neutrality by 2050, with an interim target of reducing GHG emissions to 52% below 2005 levels by 2030.[23]

According to Michigan's 2024 updated baseline calculations, net emissions in 2005 were 198.5 MMT CO_2-equivalent (MMT CO_2-e). Natural gas consumption and distribution contributed 42.2 MMT CO_2-e (21%) to this baseline, with the majority (40.5 MMT CO_2-e) attributed to direct consumption in residential, commercial, and industrial buildings. Distribution system emissions from leaks and flaring accounted for 1.32 MMT CO_2-e, while post-meter leakage on customer premises added another 0.38 MMT CO_2-e.[24]

Michigan's most recent state GHG inventory from 2019, submitted as part of the state's Priority Action Climate Plan to the EPA in 2024, shows net emissions have fallen 15.99 percent from the 2005 baseline to 166.7 MMT CO_2-e. However, natural gas emissions have not decreased proportionally. EPA inventories indicate natural gas emissions fell only 5.97% between 2005 and 2019, causing natural gas's share of overall emissions to increase from 21.3 percent to 23.8 percent.

The most current EPA GHG Inventory data for Michigan (2022) estimates statewide emissions at 167.2 MMT CO_2-e, with natural gas contributing 38.9 MMT CO_2-e as follows:

- 37.8 MMT CO_2-e (22.6%) from direct consumption in buildings
- 0.69 MMT CO_2-e (0.4%) from distribution system leaks and flaring
- 0.41 MMT CO_2-e (0.2%) from post-meter leakage.

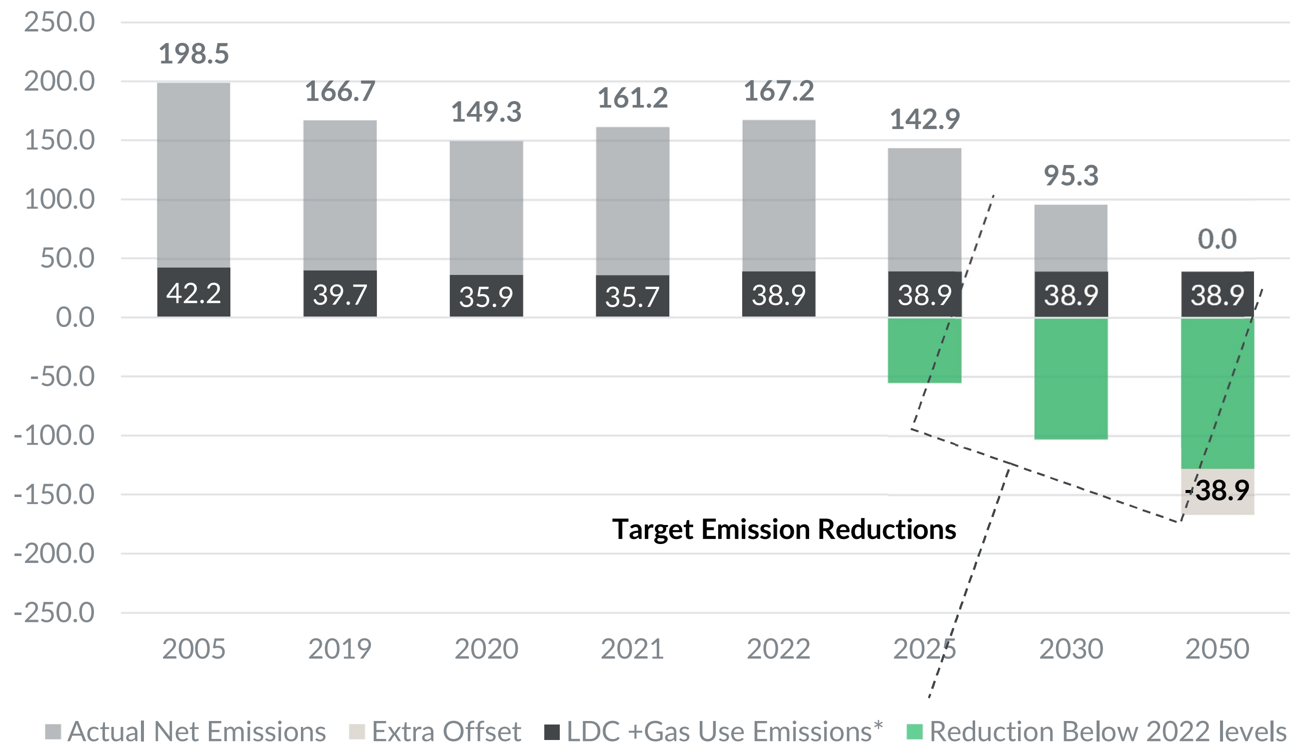
Figure 5.1 shows how recent emission estimates for Michigan compare to the baseline 2005 levels and the state's 2025, 2030, and 2050 targeted emission levels. The actual emission estimates identify the contributions from LDCs and their non-electric generation customers in the respective years. For reference,

[23] Department of Environment, Great Lakes, and Energy, "MI Healthy Climate Plan," April 2022, https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf.

[24] [Explain how we are not including electricity generation emissions in the natural gas emission totals]

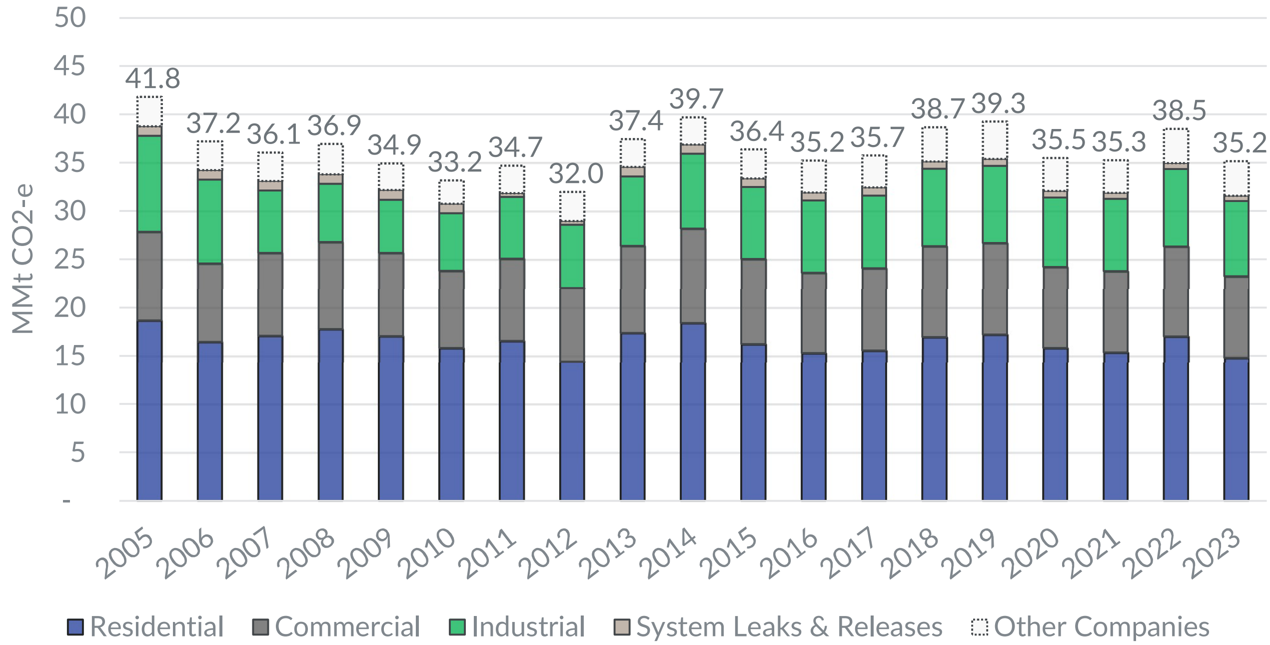
the most recent estimate of LDC emissions (2022) are included with the emission targets to show how sustained gas use at current levels would impact the state's climate goals.

Figure 5.1: Michigan Actual Emissions and Reduction Goals



To further demonstrate how emissions are attributed to LDC operators and their end-use customers in Michigan, Figure 5.2 shows the compositions of LDC sector emissions. The dark shaded bars represent the combined emissions from the three study LDCs attributed to fugitive system gas (brown), residential customer end-use (blue), commercial customer end-use (dark gray), and industrial customer end-use (green). In 2022, Consumers, DTE, and SEMCO accounted for over 93 percent of emissions from gas distribution systems – 22 percent of Michigan's total emissions.

Figure 5.2: Emissions Attributed to LDCs (excluding electric generation)



These figures demonstrate the challenge Michigan faces in meeting its climate commitments while maintaining current natural gas consumption levels. To achieve the 2025 goal, 2022 emissions must be reduced by 14.5 percent (24.3 MMT CO_2-e). If natural gas emissions remain at the 2022 levels (38.9 MMT CO_2-e), reductions from all other sectors would need to be increased by another 3.5 percent (to 19 percent below 2022 levels) to offset the lack of change in emissions from LDCs. The 2030 target becomes even more demanding if LDCs emissions remain at 2022 levels – other sectors would need to reduce emissions by 56 percent to achieve the overall 52 percent reduction if natural gas emissions remain constant.

The state's 2050 carbon neutrality goal requires eliminating or offsetting all emissions: a reduction of 167.2 MMT CO_2-e from 2022 to 2050. To achieve carbon neutrality with natural gas emissions remaining at 2022 levels, all other sectors would not only need to reach zero emissions, but also achieve negative emissions to offset the natural gas 38.9 MMT CO_2-e. A mix of 38.2 MMT CO_2-e combined in additional reductions and negative emissions (carbon capture) would be needed for the state to achieve the carbon neutral goal. A 30 percent increase in emission reductions or offsets will be required from other sectors. Given the scale of these required reductions, it becomes clear that achieving Michigan's climate goals will require significant changes to how natural gas is used and distributed throughout the state.

5.2 GAS SYSTEM INVESTMENTS DURING ENERGY TRANSITION

We show in this study that Michigan's three largest LDCs plan to invest approximately $60 billion in gas infrastructure between 2024 and 2050. Customers remaining on the gas system are projected to pay about $125 billion through base rates to cover these investments, with the majority (approximately $84.5 billion or 68 percent) going toward new investments made after 2024.

These substantial infrastructure commitments would appear to run contrary to the state's climate goals. At the same time, however, we cannot set aside the fact that natural gas meets a significant portion of Michigan's energy needs. Even after excluding natural gas used for electricity generation (317 million MMBTU), all other natural gas use (677 million MMBTU) in Michigan accounts for around 25 percent of the state's total energy consumption.[25] As long as customers are being serviced by these networks, some level of investment will be necessary to maintain system safety.

The approach to aligning investment decisions with climate goals must be tailored to the type of infrastructure project being considered. For this discussion we can group gas utility investments into one of three categories: growth and network expansion, infrastructure replacements, and system monitoring and support infrastructure projects. Each category presents different challenges and opportunities for supporting an orderly transition away from natural gas.

5.2.1 GROWTH AND NETWORK EXPANSION PROJECTS

Growth and network expansion projects extend service to new customers or increase system capacity to meet growing demand. These include new distribution mains, service lines to new customers, system reinforcement projects to increase capacity, and related supporting infrastructure like regulator stations needed for expansion areas.

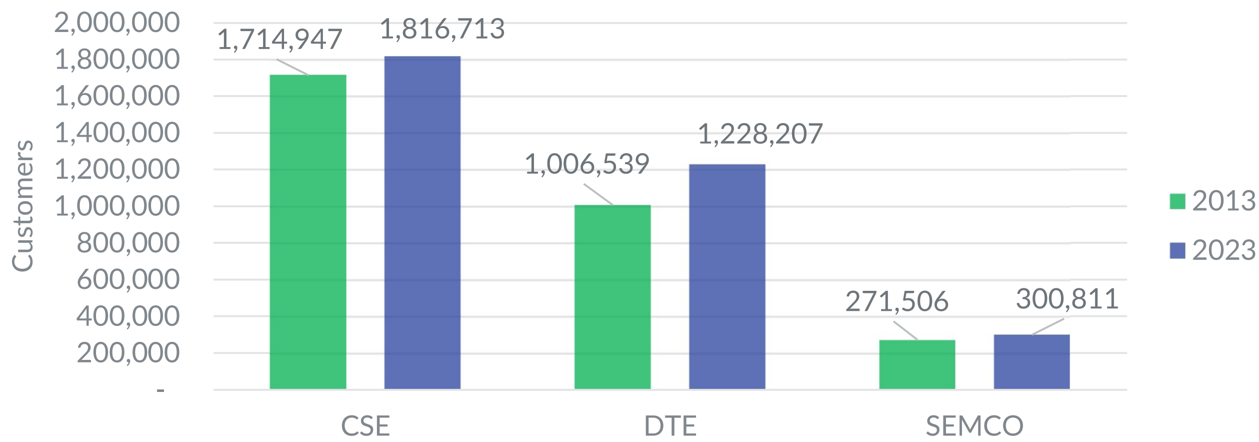
These investments most directly conflict with climate goals as they lock in new fossil fuel infrastructure and create new sources of emissions. Every new customer connected to the gas system represents an incremental rise in annual gas sector emissions that moves Michigan further away from meeting its climate targets. Based on average annual use by customer class in Michigan from 2018 to 2023, a new residential gas customer will emit on average 5 MT-CO_2-e/year; a new commercial customer will emit on average 36 MT CO_2-e/year; and a new industrial customer will emit on average 1,432 MT-CO_2-e/year.[26]

An inevitable concern when considering approaches to limit network expansion is that such policies might unreasonably constrain consumer energy choices. Examination of current customer growth and gas use trends in Michigan can help inform us of trends in consumer preference. Figure 5.3 shows that while Michigan's gas utilities have seen positive customer growth over the last ten years, the rates have been modest, averaging 0.6 percent for Consumers, 1 percent for SEMCO, and 2 percent for DTE.

[25] EIA 2022. https://www.eia.gov/state/?sid=MI#tabs-1

[26] Emissions per customer were estimated by multiplying average residential (95 MCF/year), commercial (36 MCF/year), and industrial (1,432 MCF/year) consumption in Michigan from 2018-2023 by the emission factor for combusted natural gas (0.0548 per MCF). Source: EIA.

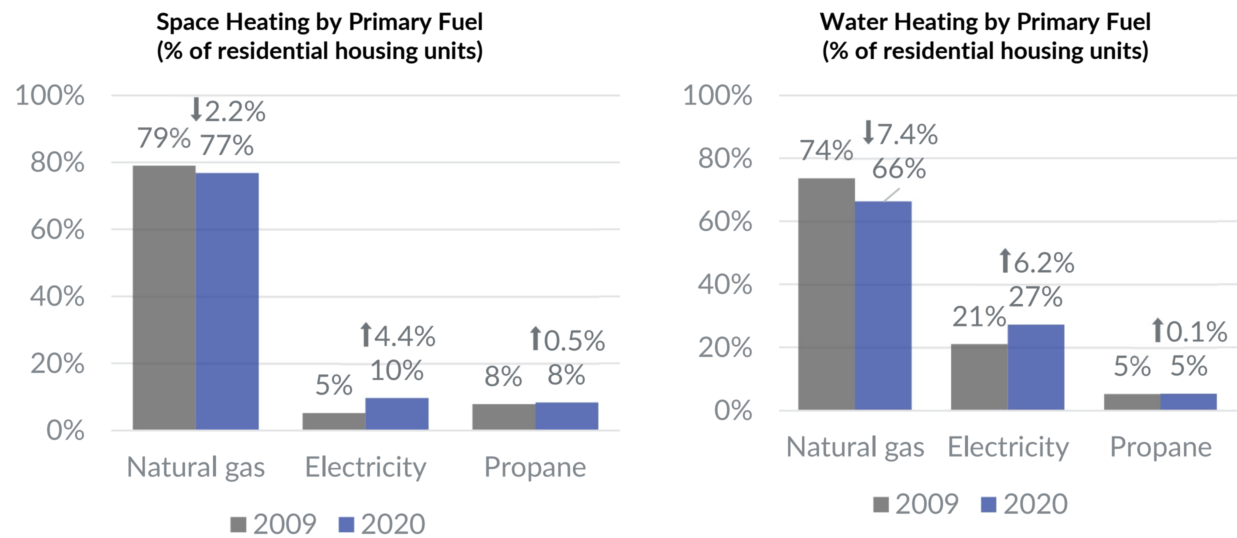
Figure 5.3: LDC Customers, 2013-2023



Source: Customer data compiled from each LDC's annual reports filed for 2013 and 2023.

In contrast to the customer growth trends, data from EIA's Residential Energy Consumption Survey shows that Michigan households' reliance on natural gas for space and water heating declined between 2009 and 2020, even as customer counts increased.

Figure 5.4: Primary Fuels for Residential Space Heating and Hot Water (2009 and 2020)



Source: U.S. Energy Information Administration (EIA), Residential Energy Consumption Survey (RECS), 2009 and 2020.

The modest customer growth and declining usage patterns shown above indicate that consumer preferences may already be shifting away from natural gas. Regulators and policymakers may be inclined to focus on the positive trends in customer growth as evidence that consumer interest in gas remains strong. However, it is important to remember that these numbers are ultimately the product of the prevailing policies in place that may actively promote gas system expansion. An essential step in the energy transition is identifying where state policy and regulation actively promote fossil fuel consumption.

One key opportunity to better align gas system growth with climate objectives is to reform how utilities evaluate line extension projects. Michigan's gas utilities currently evaluate these projects using a Net Present Value (NPV) method that compares expected revenues from new customers against the costs of constructing infrastructure to serve them. If revenues exceed costs (positive NPV), the project is generally funded through rates paid by all customers. If costs exceed revenues (negative NPV), new customers must pay the difference through monthly surcharges. This framework was designed to facilitate system growth while protecting existing customers from subsidizing uneconomic expansion.

However, this purely economic evaluation fails to account for how new gas infrastructure conflicts with climate goals. The current NPV method only considers expected revenues versus construction costs, creating a framework that encourages expansion whenever customer revenue can justify the investment. To better account for climate impacts and transition risks, the economic test for line extensions could be modified to:

1. Include the social cost of carbon from projected emissions over the life of the infrastructure
2. Factor in potential stranded asset risks if customers later electrify
3. Reduce the time frame used for evaluating future revenues to reflect transition timelines
4. Require comparison with electric alternatives before approving gas extensions.

These modifications would make gas extensions less economically favorable and create stronger incentives for electrification without imposing outright bans.

While reforming line extension policies represents one approach to managing gas system growth, some jurisdictions have opted for more direct measures to limit expansion. Several states have attempted to adopt policies that prohibit or severely limit gas connections in new construction:

- New York became the first state to ban natural gas connections in most new construction, starting in 2026 for smaller buildings and 2029 for larger ones.[27]
- California has adopted aggressive building electrification codes that effectively phase out natural gas in new construction by 2030.[28]
- Washington state adopted building energy codes that provide incentives for electric heat pumps in new construction, effectively steering builders toward electrification while avoiding an outright ban on natural gas appliances.[29]

There are multiple challenges with these attempts to ban or limit new gas connections. Bans can raise public concerns about limitations on consumer choice and regulatory overreach that may undermine the state's climate goals. In Washington, public opposition led to a winning ballot initiative that will likely result in the repeal of building codes that promote electrification over natural gas.[30] Gas connection bans have also already faced significant legal challenges, as demonstrated by the Berkeley, California case, where in spring 2023, the

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[27] Ramirez, Rachel and Ella Nilsen. "New York Becomes the First State to Pass a Law Banning Gas in New Buildings." CNN, 3 May 2023, https://www.cnn.com/2023/05/03/us/new-york-natural-gas-ban-climate/index.html.
[28] Wells, Caleigh. "California Plans to Phase Out New Gas Heaters by 2030." NPR, 23 Sept. 2022, https://www.npr.org/2022/09/23/1124511549/california-plans-to-phase-out-new-gas-heaters-by-2030.
[29] Lucia, Bill. "Judge rejects attempt to delay building code update with new heat pump rules." Washington State Standard, 24 March 2024, https://washingtonstatestandard.com/2024/03/08/judge-rejects-attempt-to-delay-building-code-update-that-includes-new-heat-pump-rules/.
[30] Cornfield, Jerry. "State panel not ready to scrap building codes targeted by gas initiative." Washington State Standard, 15 November 2024, https://washingtonstatestandard.com/2024/03/08/judge-rejects-attempt-to-delay-building-code-update-that-includes-new-heat-pump-rules/.

Ninth Circuit federal appeals court overturned the city's ban on natural gas in new construction on grounds of federal preemption.[31]

Rather than outright bans, regulators and policymakers in Michigan should focus on ways to discourage network expansion using other tools such as the modified economic tests for line extensions that account for climate impacts and stranded asset risks. In addition, customer education and campaigns to promote electrification incentive programs are needed to ensure that consumers are well informed about the options available to them when presented with an energy investment decision.

5.2.2 INFRASTRUCTURE REPLACEMENTS / SAFETY AND RELIABILITY

Infrastructure replacement projects involve replacing existing infrastructure that has reached the end of its useful life or poses safety/reliability concerns. These include the replacement of aging or leak-prone pipelines, the rehabilitation of existing mains and services, and the replacement of associated equipment like valves and regulators that serve existing customers.

Infrastructure replacement projects present a complex challenge. While aging infrastructure must be addressed to ensure public safety and maintain reliable service for current customers, these investments effectively extend the operational lifespan of natural gas infrastructure for decades. This creates a fundamental tension between immediate safety obligations and climate policy goals that requires rethinking traditional approaches to infrastructure replacement. Stakeholders must work to find a strategic balance that ensures both public safety and alignment with long-term climate objectives.

This balance will require a move away from the current infrastructure replacement approach. Each of the Michigan LDCs currently operates long-term replacement programs designed to systematically upgrade aging infrastructure components:

- Consumers operates the **EIRP**.[32] The EIRP is a 25-year program originated in MPSC Case No. U-16855 with an Order approving a Settlement Agreement that established the program with an annual funding level of $56 million. Projects in the EIRP primarily focus on replacing higher-risk gas distribution mains, including all cast iron, wrought iron, copper, X-trube, threaded and coupled (T&C), bare steel, and oxyacetylene welded steel pipe.[33] The program also includes replacement of metallic service lines associated with main replacements, transmission pipelines in high consequence areas, and certain mains not made of the targeted materials operating at low pressure. The program has been continued and modified through settlement agreements in multiple subsequent rate cases (U-17882, U-18124, U-18424, U-20322, U-20650, U-21148 and U-21308). The most recent extension came in Case No. U-21490, where a July 2024 Order approved a Settlement Agreement continuing

[31] Kempe, Ysabelle. "9th Circuit Declines to Reconsider Decision Rejecting Berkeley, California, Natural Gas Ban." Utility Dive, 3 Jan. 2024, *https://www.utilitydive.com/news/berkeley-natural-gas-ban-lawsuit-request-rehearing-en-banc-denied-federal-appeals/703514/*.

[32] Originally the EIRP was called the Main Replacement Program.

[33] Several of these main replacement categories in the EIRP refer to pipes that are higher-risk due to the technique used to join pipes together that has demonstrated higher rates of failure over time: "X-trube" is the commercial name for a type of steel pipe that used a compression-style mechanical fitting to join pipes together; "thread and coupled" (T&C) refers to steel or cast iron pipes which were joined together using a threaded coupling that connected to threaded grooves cut into the ends of each pipe; and "oxyacetylene" is a welding technique that was used on steel pipes.

the program with a spending level of $215.3 million for the 12 months ending September 30, 2025. A unique aspect of Consumers' EIRP is that it is not associated with any advanced cost recovery mechanism, unlike DTE or SEMCO. Instead, the costs of the program have been rolled into base rates on a near annual basis through frequent base rate filings.

- DTE currently operates two infrastructure replacement programs: the **GRP** and the **Pipeline Integrity Program (PIP)**. The GRP focuses on DTE distribution system improvements through replacement of cast iron and unprotected steel mains and relocating indoor meters to outdoor locations.[34] The GRP has a goal to replace all remaining cast iron and unprotected steel main and services by 2035. The PIP encompasses transmission pipeline integrity management, including in-line inspections, remote control valve installations, and records management system development. These are all activities driven by federal and state pipeline safety requirements. The programs were first approved in Case No. U-16999 (2013) in conjunction with the approval of an IRM, a surcharge that allows DTE to recover the costs of GRP and PIP projects in between base rate proceedings. Both programs and the IRP have been reconsidered and reapproved in each of DTE's subsequent base rate proceedings (U-17999, U-18999, U20940), including Case No. U-21291 that concluded in November 2024.
- SEMCO has the **MRP** and the **IRIP**. The MRP was first approved in 2011 (Case No. U-16169) as a five-year program (2011-2015) focused on addressing the accelerated replacement of all remaining unprotected steel and cast-iron mains and services. The program has since been extended and modified multiple times to add new pipe materials to the list of eligible replacements.[35] Most recently, the MRP was extended and expanded in scope in August 2024 via an approved settlement agreement in Case No. U-21624. The expanded scope for the MRP includes increasing annual replacement from 26 to 31 miles of main and the addition of pre-1983 vintage plastic and pre-1960 coated steel pipe to the list of qualifying materials. The IRIP was approved by the Commission in Case No. U-20479 in 2020 to support larger-scale system reliability and redundancy projects. The original program included five specific projects to reinforce system reliability with a budget of $54.5 million over six years (2020-2025). In Case No. U-21624, SEMCO received approval to extend the IRIP through 2027 and add two new projects: the Harris Compression Station Replacement and the Thumb Reinforcement Project. The Harris project will replace aging compressors to maintain storage field operations, while the Thumb project will install approximately 19 miles of pipeline to provide supply redundancy.

The current paradigm of the LDCs' main replacement programs focuses on wholesale replacement of entire pipe populations. As Table 5.1 shows, these programs represent long-term commitments that will extend well into the 2030s and 2040s, with each utility targeting specific pipe materials and vintages for systematic replacement.

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[34] Previously, the main replacement and meter move out activities were completed under separate programs: the Main Renewal Program (MRP) and Meter Move Out (MMO) program. These programs were recently consolidated into the GRP in Case No. U-21291.

[35] In 2013 (Case No. U-17169) the MRP was extended for three additional years and expanded to include the replacement of vintage plastic pipe installed prior to 1978 ("Pre-1978 plastic"). In 2015 (Case No. U-17824) the MRP was extended through 2020. In 2019 (Case No. U-20479), it was extended from 2021-2025.

Table 5.1: Overview of Michigan LDC Accelerated Main Replacement Programs

Company/ Program	Approval Status (date through)	Eligible Replacement Materials	Start Year	Remaining Main (miles)	Annual Miles	Anticipated End[36]
CE **EIRP**	Sept. 2025 (U-2149)	cast iron, bare steel, unprotected steel, oxyacetylene steel, threaded & coupled steel, copper	2012	1674.1 (Actual 12/2023)	141.4	2035
DTE **GRP**	2027 (U-2164)	unprotected steel, cast iron	2012	2196 (Actual 12/2023)	190	2035
SEMCO **MRP**	2027 (U-2164)	unprotected steel, vintage pre-1983 plastic, pre-1960 coated steel	2011	681.4 (Estimated 12/ 2024)	31	2046

The current paradigm of wholesale pipe replacement needs fundamental reform. The strategy underlying these programs is problematic in several ways. First, by targeting entire populations of pipe materials and vintages for replacement, utilities commit to decades of infrastructure investment without considering whether all of that infrastructure will be needed in a decarbonized future. Second, these programs often evolve to continually identify new categories of pipe for replacement, creating an endless cycle of infrastructure renewal that assumes the gas system will operate indefinitely.[37] Third, the programs' success metrics focus on miles of pipe replaced rather than actual risk reduction achieved, potentially leading to replacement of pipes that could be safely maintained through other means. Finally, this wholesale replacement approach locks in billions in capital investment that customers will pay for through rates over multiple decades, creating a financial barrier to transitioning away from natural gas.

Rather than maintaining this replace-every-pipe approach, utilities and regulators need to develop more strategic replacement criteria that consider short-term safety needs and long-term climate objectives.

The approach to infrastructure replacement must shift from wholesale replacement of entire pipe populations to a more nuanced strategy that prioritizes safety while acknowledging the reality of the energy transition. Core elements of such a program might include:

1. **Risk-Based Project Selection**: Rather than pursuing wholesale replacement of entire pipe populations, utilities should develop and apply risk-based criteria that prioritize truly necessary replacements based on empirical safety data and system conditions. This ensures that limited resources target the highest-risk infrastructure while avoiding unnecessary replacements of serviceable assets.
2. **Alternative Solutions**: The traditional assumption that replacement is the only solution for aging infrastructure needs to be challenged. Utilities should be required to evaluate alternatives that can maintain safety without wholesale replacement, such as:

[36] The anticipated end is based on either the specific end date already identified for the program (DTE) or the estimated remaining duration of the program.

[37] The propensity for replacement programs to continue to grow is illustrated by SEMCO's recent MRP extension in Case No. U-2164. As SEMCO neared completion of its initial scope targeting cast iron, unprotected steel, and pre-1978 plastic pipes, rather than winding down the program, it proposed expanding to include pre-1983 plastic and pre-1960 coated steel materials—adding 500 miles of pipeline and extending the program by another 20 years. This pattern demonstrates how replacement programs perpetually evolve to target the next category of potentially leak-prone materials, effectively creating an endless cycle of infrastructure renewal that continually extends the life of the gas system.

  - Enhanced monitoring and maintenance programs
  - Targeted repairs rather than full replacement
  - Non-pipe alternatives (NPAs) that can meet customer needs without traditional gas infrastructure.[38]
3. **Economic Tests**: Given that replacement projects effectively restart the lifecycle of gas services, these investments should be subject to economic tests similar to those used for new customer connections. These tests should:
  - Include the social cost of carbon from continued emissions
  - Factor in potential stranded asset risks
  - Consider the timeline of climate policy goals
  - Compare costs against electric alternatives.
4. **Electrification Coordination**: Infrastructure replacement projects represent natural intervention points for promoting electrification. LDCs should be required to:
  - Conduct proactive outreach to customers in areas scheduled for replacement
  - Provide information about electrification options and available incentives
  - Coordinate with electric utilities to identify opportunities for strategic electrification
  - Consider targeted retirement of gas infrastructure where electrification is viable.

Recent regulatory proceedings in Michigan suggest growing recognition of these issues. Stakeholders in DTE's 2023 base rate filing (U-21291) advocated for NPAs, consideration of repair versus replacement options, and more rigorous analysis frameworks. The MPSC's response, directing DTE to consider NPAs and update its Gas Delivery Plan to account for the energy transition, represents a step toward more strategic infrastructure planning.

However, while the Commission's recent actions represent progress, the timeline and scope of required changes lack necessary urgency. The December 2025 deadline for DTE's updated Gas Delivery Plan allows BAU replacement programs to continue for years. Moreover, the Commission missed opportunities to establish consistent requirements across utilities when it approved settlement agreements for SEMCO and Consumers in 2024 without similar provisions. A more comprehensive and expedited regulatory response is needed to ensure that infrastructure replacement decisions support rather than hinder the transition away from natural gas.

5.2.3 SYSTEM MONITORING AND SUPPORT INFRASTRUCTURE

This third category is a broader group intended to capture all other system monitoring and support infrastructure investments, enhance operations, improve monitoring capabilities, or support general utility functions without expanding or replacing the pipeline network. These include investments in leak detection technology, pressure monitoring equipment, information technology (IT) systems, and operational support facilities.

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[38] A non-pipeline alternative (NPA) refers to investments or activities designed to defer, reduce, or avoid the need for constructing or upgrading natural gas pipeline infrastructure. These solutions can include energy efficiency measures, demand response programs, beneficial electrification (such as the adoption of electric heat pumps), and other strategies that decrease reliance on traditional gas delivery systems. <Lawrence Berkeley National Laboratory, Non-Pipeline Alternatives to Natural Gas Utility Infrastructure Investments, October 2020. Available at: *https://eta.lbl.gov/publications/framework-non-pipeline-alternatives*.>

These investments are already challenging for regulators to evaluate under traditional frameworks. Unlike pipelines where costs can be clearly tied to specific customers or areas, support infrastructure often serves the entire system. Benefits can be difficult to quantify, especially for IT projects or new monitoring technologies. The rapid pace of technological change also means that assumptions about useful life and future capabilities may prove incorrect.

These challenges become even more complex when considering the energy transition. Some investments may support the transition while others could impede it. For example, installation of enhanced leak detection devices may support efforts to prioritize replacement projects around risk. Conversely, investments in long-term operational facilities or systems designed around assumptions of continued growth may no longer represent prudent choices.

There is an added layer of complexity when investment decisions are made at the enterprise level and shared across business units. This situation occurs at multi-service utilities (like DTE and Consumers) and utilities owned by a parent company with multiple other affiliated utilities (like SEMCO). The business case and cost allocation for enterprise-level projects must consider risks of customer migration from the outset. A project justified based on current customer counts or assuming stable gas revenues may no longer be prudent if significant customer migration occurs. Utilities should be required to demonstrate that corporate investment decisions and cost allocations account for various transition scenarios rather than assuming BAU conditions will persist.

Stakeholders should be considerably skeptical of any large-scale investments not intended to address specific safety or reliability concerns. The MPSC needs to establish that any investment in infrastructure or equipment with long-term service lives (5+ years) will be reviewed with increased scrutiny. For investments to be considered prudent, the LDCs should be expected to demonstrate the decision was based on some of the following:

- Scenario analysis considering different customer migration patterns
- Clear identification of how investments support the energy transition
- Enterprise cost allocation methodologies that consider transition timing
- Regular reassessment of assumptions as the transition progresses.

5.3 POLICY AND PLANNING CONSIDERATIONS

The MPSC's November 2024 Order in DTE's base rate case (U-21291) illustrates the growing tension between infrastructure investment and climate goals. While acknowledging the state's climate goals and need for change, the Commission's Order still largely supported continued system expansion and infrastructure replacement strategies.

The conflicting messages in the Order illustrate how existing regulatory frameworks in Michigan and states across the country are straining to address the challenges of the energy transition. The MPSC Act requires the MPSC to ensure utilities recover "reasonable and prudent" costs while maintaining safe and reliable service, but provides limited guidance for addressing declining usage, customer departures, or alignment with climate goals.

Addressing these challenges requires careful consideration of three interrelated policy areas:

1. How to evolve rate design and cost recovery approaches that were built for growing systems?
2. How to ensure equity and affordability during a potentially lengthy transition period?
3. How to coordinate infrastructure planning across gas and electric systems to support decarbonization goals?

Below these three policy and planning considerations are briefly discussed and possible tools or solutions are proposed. Please note that this section is not meant to be an exhaustive assessment of the regulatory issues that need to be addressed but rather is intended to support future stakeholder dialogue.

5.3.1 RATE DESIGN AND COST RECOVERY

A fundamental policy consideration is how regulation of gas utilities needs to evolve during a transition away from natural gas. Current regulatory frameworks, designed around assumptions of growing or stable gas demand, may no longer be appropriate as climate policies and market forces drive electrification. This creates two key challenges: (i) ensuring fair cost recovery for utilities while protecting customers from excessive rates; and (ii) managing the risk of stranded assets.

Base rate projections in Section 4 show substantial increases even assuming a stable customer base - with residential bills increasing between 81 percent and 148 percent by 2050 across the three utilities. However, these projections likely underestimate actual rate impacts as they do not account for customer migration away from natural gas. The gas distribution system has high fixed costs that must be recovered regardless of how many customers remain.

The challenge is magnified by current regulatory approaches that allow utilities to recover capital investments over 60-70 years. Many investments being made today would still be in rate base well beyond 2050, when Michigan aims to achieve carbon neutrality. This creates significant stranded asset risk if climate policies or market forces drive customer migration faster than anticipated.

Several regulatory tools could help address these challenges:

- Modified rate design approaches that better align fixed cost recovery with system usage
- Shortened depreciation schedules for new investments to reduce stranded asset risk
- Regular reassessment of infrastructure investment plans based on updated transition scenarios
- Creation of regulatory frameworks that provide utilities incentives to maintain rather than replace and expand their systems.

5.3.2 EQUITY AND AFFORDABILITY

Energy transitions often raise significant equity concerns, as the costs and benefits of change tend to be unevenly distributed across society. The transition away from natural gas is likely to follow patterns seen in other energy technology adoptions, where access to capital and ownership status heavily influences who can participate in the transition and when. This creates a risk that vulnerable populations could bear a disproportionate share of transition costs while facing greater barriers to accessing benefits.

Experience with electric vehicle and rooftop solar adoption shows that higher-income households typically transition first to new technologies. This pattern raises particular concerns about the gas transition, as remaining customers bearing increasing fixed costs are more likely to be lower-income households with limited ability to electrify or invest in efficiency improvements.

Several structural barriers contribute to this dynamic:

- Limited upfront capital for electrification investments
- Higher proportion of renters with less control over heating systems
- Older, less efficient housing stock requiring more extensive upgrades
- Limited access to financing options
- Split incentives between landlords and tenants

Addressing these equity challenges requires developing support mechanisms focused on vulnerable customers and communities:

- Income-based rates or bill assistance programs specifically designed for the transition period
- Targeted electrification incentives prioritizing low-income households
- Rental property programs that address split incentive barriers
- Small business support programs combining energy audits with financing assistance
- Requirements for utilities to track and report on demographic distribution of transition impacts
- Creation of dedicated transition assistance funds from utility bill surcharges
- Neighborhood-scale transition programs to achieve economies of scale
- Partnerships with community organizations to enhance program reach.

5.3.3 INFRASTRUCTURE PLANNING COORDINATION

The transition away from natural gas requires a fundamental shift in how utilities plan and deploy infrastructure investments. Traditional planning approaches that evaluate gas system investments in isolation are no longer sufficient when considering climate goals and increasing electrification. The MPSC's September 2024 Order in Case No. U-20147 provides valuable guidance for developing more comprehensive planning frameworks. While focused on electric distribution planning, the Order establishes several principles equally relevant to gas system planning:

- Development of transparent long-term visions aligned with state policy goals
- Integration of climate risks into scenario planning
- Clear demonstration of alignment with state emissions targets
- Thorough justification of spending proposals with robust affordability analysis
- Requirements for community engagement
- Coordination across various infrastructure planning efforts.

The key for the gas sector is ensuring that while critical safety and reliability needs continue to be met, infrastructure planning supports rather than hinders the transition to a low-carbon energy system. This requires moving beyond project-by-project evaluations to consider how individual investments fit within broader transition pathways. Several regulatory and policy tools could help ensure better alignment of infrastructure planning with state goals:

- Joint gas-electric system planning requirements to identify efficient electrification opportunities
- Modified economic tests for infrastructure investments that incorporate transition timelines
- Requirements to evaluate NPAs including district heating systems and geothermal networks

- Development of clear metrics for measuring planning alignment with climate goals
- Creation of stakeholder advisory groups to guide planning processes
- Regular updates to planning requirements based on transition progress
- Coordination mechanisms between utility infrastructure plans and local/regional development plans.

SECTION 6 NEXT STEPS

This report has analyzed the potential rate impacts of BAU investment in gas infrastructure by Michigan's three largest LDCs. The analysis shows that Michigan's LDCs plan to invest approximately $60 billion in gas infrastructure between 2024 and 2050. Under this scenario, customers would pay about $125 billion through base rates to cover these investments, with the majority (approximately $84.5 billion) going toward new investments made after 2023. These investments would drive substantial bill increases, even assuming a stable customer base:

- Consumers residential bills increasing 148 percent by 2050
- DTE residential bills increasing 100 percent by 2050
- SEMCO residential bills increasing 81.4 percent by 2050.

These rate impacts must be considered alongside Michigan's climate commitments, including a 52 percent reduction in emissions by 2030 and carbon neutrality by 2050. Natural gas currently accounts for about 23 percent of Michigan's greenhouse gas emissions, with the vast majority coming from direct consumption rather than system leakage. Meeting climate targets while maintaining current gas consumption levels would require unrealistic reductions from other sectors - requiring a 56 percent drop in other emissions by 2030 if gas emissions remain constant.

While natural gas will certainly play a crucial role in Michigan's energy system over the next decade, its role by 2050 is less certain. Rather than forcing an abrupt transition, the key is to create frameworks that allow for evolution to occur organically as customers and utilities face investment decisions. As households replace aging furnaces, businesses upgrade facilities, and utilities maintain infrastructure, each decision point presents an opportunity to evaluate alternatives to traditional gas service. However, making these decisions effectively requires addressing several critical questions.

- **How should gas infrastructure planning evolve to align with climate goals?**
- **Are there limits that should be established on system expansion or growth projects? If so, how do these limits differ for new connections on the existing system versus new customers connecting to a system expansion?**
- **Should the line extension policies be changed in any way?**
- **When do gas infrastructure replacement projects represent opportunities to promote electrification?**
- **What are the scenarios or circumstances when a replacement project does not represent an opportunity to promote electrification?**
- **Should expectations be established that when LDCs develop the list of construction activities to be pursued each year, replacement projects will focus only on the assets with the highest risk of failure?**
- **Are there reporting requirements that can be adopted to support the MPSC and stakeholders in monitoring directives to prioritize project selection around risk and system safety?**
- **What regulatory changes are needed to manage stranded asset risks?**

- **How can the transition be managed to protect vulnerable customers?**
- **How should transition costs be allocated?**
- **What other types of energy services or business models might the LDCs be able to pivot to in the future?**

These questions cannot be answered in isolation – they require coordinated efforts from policymakers, regulators, utilities and stakeholders. The findings of this report suggest that continuing BAU investment in gas infrastructure creates risks for both ratepayers and utilities while potentially hindering the achievement of state climate goals. However, with proper planning and policy frameworks, Michigan has an opportunity to manage an orderly transition that ensures safety and reliability while advancing climate goals and protecting vulnerable customers.