STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE GAS COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority	U-21973 ALJ Christopher S. Saunders

DIRECT TESTIMONY OF MICHAEL WALSH, Ph.D.

ON BEHALF OF

THE CITY OF ANN ARBOR

March 13, 2026

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and business address.

A. My name is Michael J. Walsh. I am the Managing Partner of Groundwork Data, Inc. My business address is 51 Lockeland Avenue, Arlington, Massachusetts 02476.

Q. Please describe your educational background and professional experience.

A. I hold an A.B. in Chemistry from Colby College, and a Ph.D. in Environmental Engineering from Cornell University. My doctoral research and education focused on marine biogeochemistry. I conducted postdoctoral research as a fellow at the Bentley University Center for Integration of Science and Industry on the topics of integrated macro-energy system modeling, lifecycle and technoeconomic assessment, and technology transitions in the bioenergy industry.

From 2017 to 2019, I served as the technical lead of the Carbon Free Boston Study at the Boston University Institute for Sustainable Energy, overseeing a comprehensive technical analysis and stakeholder engagement exercise. In 2019, I was hired by the Cadmus Group, where my primary responsibility was as project director for the Massachusetts 2050 Decarbonization Roadmap Study ("2050 Roadmap"), a comprehensive technical analysis and stakeholder engagement exercise that served as the foundational research for the Executive Office of Energy and Environmental Affairs' ("EEA") decarbonization planning.

In 2021, I launched an independent practice that evolved into Groundwork Data focused primarily on the future of gas and future of heat. In this role, I have overseen several studies and projects on the "future of gas" and the "future of heat" in Massachusetts and other jurisdictions. To date, Groundwork Data has worked only with governmental or nonprofit public-interest organizations.

Q. On whose behalf are you submitting your testimony in this proceeding?

A. My testimony is on behalf of the City of Ann Arbor ("Ann Arbor" or "the City").

Q. Have you previously testified before this Commission or as an expert in other proceedings?

A. My usual role in testifying before public utility regulatory agencies is in an advisory capacity as a buildings and gas sector decarbonization expert. In the Commonwealth of Massachusetts, I have testified before the Massachusetts Department of Public Utilities on behalf of the Attorney General's Office on the Massachusetts gas companies' Climate Compliance Plans (D.P.U. 25-41 through 25-44/45); and, on behalf of the Conservation Law Foundation ("CLF") on Liberty Utility's petition for approval of an agreement to purchase renewable natural gas from Fall River RNG, LLC (D.P.U. 22-32). I have also acted as a non-testimonial expert in other dockets as a consulting expert and commenter, notably in the Department of Public Utilities' "Future of Gas Investigation" D.P.U. 20-80 on the topics of Pathways Analysis, Line Extension Allowances, and Renewable Natural Gas.

I have also testified before the Rhode Island ("R.I.") Public Utilities Commission ("P.U.C.") on behalf of the CLF on Rhode Island Energy's 2024 and 2025 infrastructure, safety, and reliability proceedings (R.I. P.U.C. 23-49-NG and R.I. P.U.C. 24-55-NG). I have also participated as a technical expert in the R.I. "Future of Gas" investigation (R.I. P.U.C. 22-01-NG) on behalf of the CLF and Sierra Club. And I have recently testified before the Colorado Public Utilities Commission on Xcel Energy's 2025-2030 Gas Infrastructure Plan (CO. P.U.C. 25A-0220G) on behalf of Rewiring America.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with an independent assessment of DTE Gas Company's ("DTE," "DTE Gas," or "the Company") proposed investments and business strategies in light of the converging challenges facing gas distribution systems. Specifically, my testimony: (1) identifies four structural disruptors facing DTE's gas system – growing infrastructure costs, state and local climate action, increasing competition from heat pump technology, and Michigan population decline – and demonstrates that these challenges are independently validated by the Michigan Department of Environment, Great Lakes, and Energy; (2) evaluates DTE's response to the Commission's November 2024 directive to consider energy transition pathways in its Gas Delivery Plan, and finds it insufficient; (3) presents a revenue requirement model projecting residential bills and per-customer costs through 2050 under seven demand scenarios, demonstrating that even modest declines in gas demand materially increase costs for remaining ratepayers and that neither renewable natural gas nor hybrid heating presents a viable path to system-wide decarbonization; (4) examines the limitations of DTE's emissions-factor-based approach to methane mitigation and recommends a transition to measurement-based strategies; (5) evaluates DTE's claims regarding renewable natural gas ("RNG"), demonstrating that RNG is fundamentally supply-constrained, driven by distortive federal subsidies, and an inferior use of limited bioenergy resources; (6) describes the growing field of non-pipeline alternatives ("NPA") and recommends that DTE be directed to systematically identify and evaluate NPA opportunities across its system; (7) analyzes DTE's Customer Attachment Program, demonstrating that existing ratepayers finance approximately 94% of new service connection costs system-wide and that the program's revenue projections are based on assumptions contradicted by DTE's own Gas Delivery Plan; and, (8) summarizes how five peer states are addressing “Future of Gas” issues through regulatory proceedings and policy changes, including lessons from the Peoples Gas experience in Illinois. Throughout these reviews, I offer recommendations that the Commission: (1) reform line extension allowances; (2) direct DTE to begin non-pipeline alternative evaluation; and (3) initiate a comprehensive Future of Gas proceeding with four defined workstreams and twelve-month deliverables.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit AA-29	Resume of Michael Walsh
Exhibit AA-30	State Future of Gas Proceeding Matrix
Exhibit AA-31	DTE Gas Revenue Requirement Model
Exhibit AA-32	Discovery Response MECCUBDG-5.2b
Exhibit AA-33	Discovery Response STDG-2.13
Exhibit AA-34	Discovery Response AGDG-6.221
Exhibit AA-35	Discovery Response MECCUBDG-5.12a-b
Exhibit AA-36	EGLE Report: *Clean, Safe, and Affordable* (Excerpts)
Exhibit AA-37	Michigan Population Projections Through 2050 (Excerpt)
Exhibit AA-38	Michigan Population Growth Domestic Gains (Excerpt)
Exhibit AA-39	Discovery Response MECCUBDG-3.16g
Exhibit AA-40	DHInfrastructure & CUB, *Potential Bill Impacts of Business-as-Usual in Michigan* (Excerpt)
Exhibit AA-41	ICF, Michigan Renewable Natural Gas Study (Excerpt)

Exhibit AA-42	Discovery Response AADG-1.6
Exhibit AA-43	MPSC Form P-522, p. 305B and 306C
Exhibit AA-44	Olaguer, E.P. et al., *The Michigan-Ontario Ozone Source Experiment (MOOSE): An Overview*
Exhibit AA-45	Sargent, M.R. et al., "Majority of US urban natural gas emissions unaccounted for in inventories"
Exhibit AA-46	Direct Testimony of Robert Ackley from Case No. U-21291 (Excerpt)
Exhibit AA-47	American Gas Foundation, *Renewable Natural Gas Supply Assessment* (Excerpt)
Exhibit AA-48	EPRI, *Net-Zero Scenarios 2.0* (Excerpt)
Exhibit AA-49	Cole Rosengren, "How the EPA's Renewable Fuel Standard program changes could be boon for landfill and AD operators," *Waste Dive*
Exhibit AA-50	Jacob Wallace, "Biogas groups, lawmakers jockey for changes as EPA nears final rule on eRIN market," *Waste Dive*
Exhibit AA-51	New York State Energy Plan, *Low-Carbon Alternative Fuels* (Excerpt)
Exhibit AA-52	New York State Energy Research and Development Authority, *Considerations for Low-Carbon Alternative Fuel Use in New York State* (Excerpt)
Exhibit AA-53	Attachment to Discovery Response MECCUBDG-3.12a (Heat Pump Emissions tab)
Exhibit AA-54	Attachment to Discovery Response MECCUBDG-3.12a (GHG Emissions Factors tab)
Exhibit AA-55	RMI & National Grid, *Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization* (Excerpt)
Exhibit AA-56	Discovery Response MECCUBDG-3.8a

Exhibit AA-57	Discovery Response FLODG-4IV2bii
Exhibit AA-58	Discovery Response AADG-2.7a
Exhibit AA-59	Discovery Response AADG4.4a-f
Exhibit AA-60	U.S. Energy Information Administration, Natural Gas Annual 2024, Table 15
Exhibit AA-61	U.S. Energy Information Administration, Natural Gas Annual 2024, Table 19
Exhibit AA-62	Discovery Response AADG-2.8a
Exhibit AA-63	Discovery Response AADG-2.9fi-iii
Exhibit AA-64	RMI, "Cutting These Subsidies Could Save States Millions of Dollars"
Exhibit AA-65	National Regulatory Research Institute, *Line Extensions for Natural Gas: Regulatory Considerations* (Excerpt)
Exhibit AA-66	California Energy Commission, *The Challenge of Retail Gas in California's Low-Carbon Future* (Excerpt)
Exhibit AA-67	Citizens Utility Board of Illinois & Groundwork Data, *Peoples Gas: Escalating Business Risk in a Changing Energy Landscape* (Excerpt)
Exhibit AA-68	Stephanie Zimmerman, "Peoples Gas Pipe Replacement is Costing Chicagoans More," Chicago Sun-Times (Feb. 16, 2021)
Exhibit AA-69	Robert Channick, "Peoples Gas Pipeline Program Will Cost Another $12.8 Billion to Complete," Chicago Tribune (Oct. 29, 2024)

II. <u>CHALLENGES FACING THE GAS SYSTEM</u>

Q. What are the key challenges facing natural gas distribution systems in Michigan and nationally?

A. Natural gas distribution systems across the country, including DTE's, face three converging disruptors that are fundamentally changing the economics and long-term viability of the gas utility business model (Figure 1). These are: (1) growing costs of maintaining and expanding gas distribution infrastructure; (2) mounting climate action not just from governments, but also from customers; and (3) increasing competition from non-gas technologies, particularly electric heat pumps.

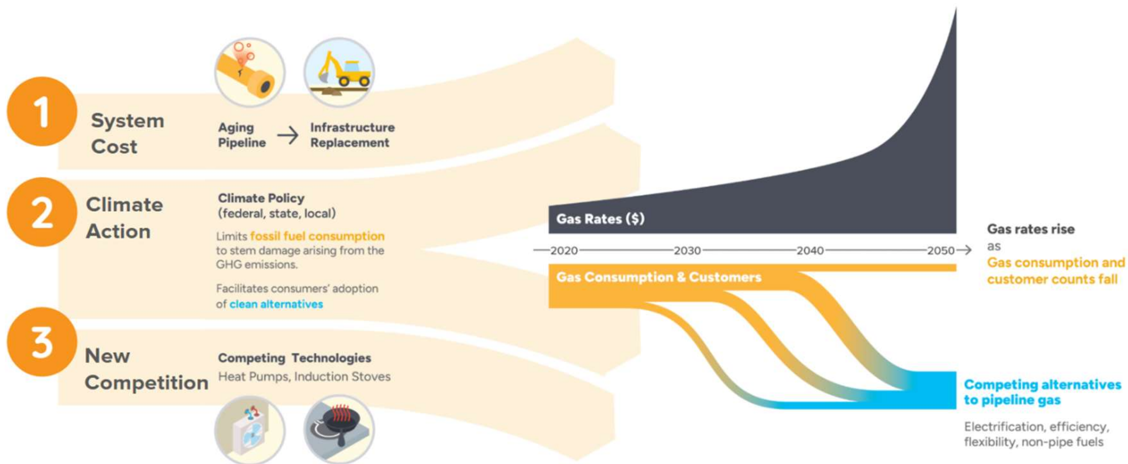

Figure 1. *Illustration of how increasing gas costs concentrate on a declining customer base as the gas system is disrupted. Groundwork Data figure.*

In Michigan, gas utilities face a fourth challenge: statewide population decline that threatens to reduce the gas customer base even without attrition to other fuels. The combined and accelerating effect of these trends demands careful regulatory attention. As I describe below, each is clearly present in Michigan. Whether gas demand ultimately declines modestly or substantially, these trends create material risk for existing ratepayers who fund the system's fixed costs. This risk justifies heightened regulatory scrutiny of DTE's investment plans.

Q. What are the consequences of these combined disruptors for gas ratepayers?

A. The fundamental problem is that gas distribution is a high-fixed-cost system. The vast majority of costs are incurred regardless of the amount of gas flowing through the system. When gas consumption declines, whether through efficiency, electrification, or customer departure, those fixed costs must be spread over fewer units of gas consumed and ultimately fewer customers. This concentrates costs on the customers who are unable to reduce their gas usage, a group that is likely to be increasingly constrained in their ability to manage their gas use.

Regulators in other states have recognized this dynamic and have begun to address it through formal proceedings and policy changes. This is discussed in detail in Section IX. The Michigan Public Service Commission ("MPSC" or "the Commission") has taken initial steps in this direction through the updated Gas Delivery Plan ("GDP") requirements established in Case No. U-21291, [1] but as I discuss in subsequent sections, DTE's response to these requirements has been insufficient.

II-A. Growing Costs for Gas Distribution Infrastructure

Q. How are gas distribution infrastructure costs changing?

A. Gas distribution infrastructure costs are rising significantly, both nationally and at DTE specifically. This is driven by multiple factors: aging infrastructure requiring accelerated replacement, increasingly stringent federal pipeline integrity mandates, escalating contractor and labor costs, and the inherent difficulty of working on increasingly complex system management projects. These cost pressures are largely structural and will persist regardless of whether gas demand grows, stagnates, or declines.

At DTE, the evidence of cost escalation is pervasive in this proceeding. The Company's Gas Renewal Program ("GRP") cost per installed mile has increased sharply, from $1.08

[1] Case No. U-21291, Order, November 7, 2024, p. 216-17.

million in 2023 to $1.69 million in 2025 (a 56% cumulative increase).[2] The GRP itself is ramping up from 127 miles per year in 2026 to an average of 196 miles per year from 2027 through 2037.[3] Pipeline integrity operations and maintenance ("O&M") costs are nearly tripling, from an average of approximately $14.5 million per year over 2019–2024 to projected levels of $30 million in 2026 and $42 million in 2027.[4] The Company has introduced a new Regulator Station Replacement Program ("RSRP"), but with approximately 2,100 legacy regulator stations remaining and a current pace of roughly 15 per year, complete replacement would take approximately 140 years.[5]

Additional testimony is being submitted by Rick Brown, who provides a detailed engineering assessment of several specific large capital projects proposed in this case, including the Carlton Main Replacement Project, Fort Street Main Replacement Project, and the East Petoskey Pipeline Reinforcement Project. The cost trajectories of these projects illustrate the broader pattern: gas infrastructure spending is growing at rates that exceed general inflation, and this trend is expected to continue for decades.

II-B. Climate Action at the State and Local Level

Q. What climate policies are relevant to gas demand in Michigan?

A. Michigan has established a clear policy direction toward decarbonization that directly impacts the gas distribution system. The state released the MI Healthy Climate Plan in 2022, which establishes a target of economy-wide carbon neutrality by 2050. Specifically relevant to this proceeding, the MI Healthy Climate Plan targets a 17% reduction in

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[2] Janness, Direct Testimony, p. 28-29.
[3] Exhibit AA-32.
[4] Exhibit AA-33; *see also*, Exhibit AA-34.
[5] Exhibit AA-35.

emissions from heating homes and businesses by 2030, relative to a 2005 baseline.[6] Additionally, Public Act 229 of 2023 increased energy-efficiency requirements for Michigan utilities, further reducing natural gas consumption.[7] The Commission itself has recognized the need for gas utilities to begin planning for the energy transition, requiring DTE to file an updated Gas Delivery Plan in the last rate case incorporating, among other things, how changing customer demand, electrification, and decarbonization will impact the distribution system.[8]

DTE's own witness, Mr. Decker, acknowledges that "State or Federal legislative and regulatory developments could impact natural gas demand and DTE Gas's capital plans."[9] Yet the Company also claims that it is "not currently aware of any proposed legislation or regulation that would materially impact its current business."[10] This posture is internally contradictory: in its most recent prior rate case, DTE's own return-on-equity witness cited decarbonization risk – including the City of Ann Arbor's franchise negotiations – as a basis for seeking a higher equity return.[11] The Company cannot credibly invoke climate risk when seeking higher shareholder returns and then dismiss it when the question is whether to plan prudently for that same risk.

Q. Is climate action also occurring at the local level in Michigan?

A. Yes. The City of Ann Arbor, on whose behalf I submit this testimony, adopted its A^2ZERO Carbon Neutrality Plan in June 2020, committing the community to achieving

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[6] MI Healthy Climate Plan; *see also*, Exhibit A-12, Schedule B5.6, p. 81 (Figure 72).
[7] *See* MCL 460.1077; *see also*, Decker, Direct Testimony, p. 22.
[8] Case No. U-21291, Order, November 7, 2024, p. 216-17.
[9] Decker, Direct Testimony, p. 17.
[10] *Id.*
[11] Exhibit AA-26.

carbon neutrality by 2030.[12] Transitioning away from fossil gas is a core strategy of this plan.

Ann Arbor's building electrification goals are backed by dedicated funding, established programs, and active projects. The City's Community Climate Action Millage generates roughly $7 million annually to fund A^{2}Zero decarbonization initiatives.[13] The City's Heat Pump Concierge program provides streamlined incentives, free system design, guaranteed price estimates, and contractor vetting for residents[14] – and the City has seen HVAC permits for heat pump installation increase substantially in the past two years, from 6.6% of residential HVAC permits and 3.1% of commercial HVAC permits in 2023 to 9.7% of residential permits and 13.3% of commercial permits in 2025.[15] The City's Sustainable Energy Utility, launching in 2026, will further promote progress.[16] Both the City and the University of Michigan are already actively developing large networked geothermal systems.

Ann Arbor's rapid progress demonstrates that its residents, which make up roughly 4% of DTE customers, cannot be expected to remain in DTE's customer base in 2050 at current levels. The results of the revenue requirement model detailed in Section IV of my testimony demonstrate that even this 4% departure represents an increasing risk that DTE's investment planning should, but does not, account for.

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[12] City of Ann Arbor, A^{2}ZERO Carbon Neutrality Plan (adopted June 2020).
[13] City of Ann Arbor, 2022 Community Climate Action Millage.
[14] City of Ann Arbor, A2ZERO Heat Pump Concierge.
[15] City of Ann Arbor, A^{2}ZERO Dashboard.
[16] City of Ann Arbor, Sustainable Energy Utility.

<u>II-C. Increasing Competition from Non-Gas Technologies</u>

Q. What non-gas technologies are emerging as competitors to gas heating?

A. The most significant competitive threat to the gas distribution system is the electric air-source heat pump. Modern cold-climate heat pumps can operate efficiently at temperatures well below zero degrees Fahrenheit, a capability that was not commercially viable a decade ago. These systems offer several advantages over gas heating that are relevant to this proceeding.

First, heat pumps are *modular*. A homeowner can install a single mini-split unit to heat and cool a primary living space for a few thousand dollars, without the need for ductwork or gas piping. Second, heat pumps provide *both heating and cooling,* eliminating the need for a separate air conditioning system. Third, heat pumps can operate in *hybrid configurations* alongside existing gas or propane heating equipment. This hybrid approach significantly reduces gas consumption (potentially by 50–80% depending on design) while retaining gas backup for the coldest hours of the year.

Q. Are there particular consumer segments where heat pump adoption may be especially beneficial?

A. Yes. Consumers currently using propane for heating are a particularly promising segment for full or dual-fuel/hybrid heat pump adoption. The EGLE building decarbonization roadmap notes that Michigan ranks first in the nation in residential propane consumption, with over 400,000 homes heated by delivered fuels, and finds that the average Michigan propane household would save approximately $660 per year by switching to a heat pump

– and significantly more under improved rate design.[17]

This observation has direct implications for DTE's Customer Attachment Program ("CAP"). DTE attributes much of its new customer growth to "increased demand by homeowners for conversion from the higher cost of propane to natural gas, particularly in the community expansion space."[18] But if these propane customers could achieve substantial heating cost savings through a hybrid heat pump/propane configuration, without requiring millions of dollars in ratepayer-funded gas main extensions, then the economic justification for these extensions is weaker than the Company represents. Moreover, from a system-wide perspective, encouraging hybrid heat pump adoption among propane customers could deliver benefits to the electric grid (higher winter utilization of electric infrastructure) that benefit all electricity ratepayers, without imposing new costs on gas ratepayers. Section VIII of my testimony will detail concerns with DTE's CAP.

Q. How competitive are heat pumps with natural gas?

A. Michigan's relatively low natural gas prices create a cost structure that currently favors gas heating on an operational basis. The cost of an electrification retrofit can be substantial, given the need for new equipment and the installation of enabling building envelope improvements. In contrast, in new construction, installing ducted heat pumps or ductless mini-split heat pumps can avoid the cost of gas piping, which is especially advantageous if cooling is desired.

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[17] Clean, Safe, and Affordable: A Policy Roadmap for Efficient and All-Electric Homes in Michigan (March 2026), prepared by Institute for Energy Innovation, Michigan Energy Innovation, and 5 Lakes Energy for the Michigan Department of Environment, Great Lakes, and Energy (Relevant excerpts at Exhibit AA-36).

[18] Huffman, Direct Testimony, p. 39.

The fact that gas is cheaper *today* also does not mean that gas will remain the lowest-cost option over the 20-to-50-year lifetime of the infrastructure investments this Commission is being asked to approve. Gas distribution costs are escalating rapidly, as described above. Heat pump technology continues to improve in both efficiency and cost. Electric rate design could further affect the economics of heat pump adoption. A March 2026 EGLE-commissioned study found that under existing Michigan electric tariff structures, a natural gas customer switching to a heat pump would see annual energy costs increase, but that an alternative tariff incorporating seasonal volumetric delivery charges—lower distribution rates in winter when system capacity is abundant, higher in summer—produces annual bill savings when paired with building envelope improvements, without shifting costs to non-adopters.[19] Several states have already begun addressing this barrier: In Massachusetts, all investor-owned utilities offer a Residential Heat Pump Rate that reduces per-kilowatt-hour distribution charges during winter months, reflecting the lower cost of serving heating load when distribution system capacity is abundant. The EGLE report recommends that the MPSC require Michigan utilities to implement similar heat pump-specific rate plans and adopt time-differentiated pricing that reflects seasonal cost-of-service differences.[20] Notably, DTE's own Guidehouse Heat Pump Breakeven Analysis did not account for seasonal electricity pricing in its evaluation of heat pump economics.[21] Further, climate policies may impose

[19] Clean, Safe, and Affordable: A Policy Roadmap for Efficient and All-Electric Homes in Michigan (March 2026), prepared by Institute for Energy Innovation, Michigan Energy Innovation, and 5 Lakes Energy for the Michigan Department of Environment, Great Lakes, and Energy, (Relevant excerpts at Exhibit AA-36).

[20] *Id.*

[21] Exhibit A-29. Schedule 1.

costs on gas consumption that do not exist today.

II-D. Population Decline in Michigan

Q. How can we expect Michigan population change to impact DTE business?

A. Gas companies in Michigan face the added challenge of a flat or declining population. The Michigan Center for Data and Analytics projects that the state's population will decrease by approximately 2% from 2025 to 2050. Population decline is most severe in Wayne County, the most populous county in DTE Gas service territory, whose population is projected to decline 184,000 people (10.6%) by 2050.[22] DTE is unlikely to maintain indefinite customer growth under these conditions, especially if it is unable to attract new customers in propane-heated homes.

II-E. Conclusion

Q. Is there a historical precedent for declining gas consumption in Michigan?

A. Yes. DTE's own Gas Delivery Plan reports that the Company has achieved an 18% reduction in weather-normalized demand per customer since 2005 and projects continued 1% annual energy-efficiency savings.[23] This is consistent with a long-standing structural trend: building energy codes have grown more stringent over time, appliances have become more efficient, and utility energy waste reduction ("EWR") programs have steadily reduced per-customer consumption. Public Act 229 of 2023 will accelerate this trend by increasing EWR targets.[24]

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[22] Michigan Center for Data and Analytics, "Statewide Population Projections through 2050 Report" (April 2024) (Relevant excerpt at Exhibit AA-37); Michigan Center for Data and Analytics, "Michigan Shows Population Growth and Slight Domestic Gains in 2025," (January 2026) (Relevant excerpt at Exhibit AA-38).

[23] Exhibit A-12, Schedule B5.6, p. 85.

[24] *See* MCL 460.1077.

What is new is that these historical structural efficiency gains can now be significantly *accelerated* by the emergence of heat pump technology. Where efficiency improvements historically reduced gas consumption incrementally, heat pump adoption can reduce a customer's gas consumption by 50–80% (in a hybrid configuration) or eliminate it entirely. This means the trajectory of declining per-customer consumption that DTE itself acknowledges could steepen materially, even if the timing and pace remain uncertain. These impacts could be further magnified by population decline.

Q. Has a Michigan state agency independently validated the challenges to the gas system described in this section?

A. Yes. In March 2026, the Michigan Department of Environment, Great Lakes, and Energy ("EGLE") released "Clean, Safe, and Affordable: A Policy Roadmap for Efficient and All-Electric Homes in Michigan," prepared by the Institute for Energy Innovation, Michigan Energy Innovation Business Council, and 5 Lakes Energy.[25] The report models the impacts of building electrification and energy efficiency policies consistent with the MI Healthy Climate Plan's goal of carbon neutrality by 2050.

The EGLE report's findings are consistent with and reinforce each of the disruptors I describe above. On growing infrastructure costs, the report cites projected increases in monthly gas delivery charges across Michigan's three major gas utilities, including an increase at DTE from approximately $80 to $177 per month by 2050 — a projection independently corroborated by my own revenue requirement model. On climate action,

[25] Clean, Safe, and Affordable: A Policy Roadmap for Efficient and All-Electric Homes in Michigan (March 2026), prepared by Institute for Energy Innovation, Michigan Energy Innovation, and 5 Lakes Energy for the Michigan Department of Environment, Great Lakes, and Energy, (Relevant excerpts at Exhibit AA-36).

the report recommends that the MPSC conduct a study evaluating the role of natural gas in Michigan's clean energy future, that the Commission consider non-pipeline alternatives, and that line extension allowances be eliminated – each of which I independently recommend in this testimony. On competition from non-gas technologies, the report's building inventory model finds that Michigan must install approximately 2.8 million heat pumps by 2040 to meet the state's decarbonization targets, and models delivered fuel customers as an attractive early market for fuel switching. On population and demand decline, the report's Energy Policy Simulator modeling projects the elimination of residential building sector Scope 1 emissions by 2050, with natural gas consumption declining sharply after 2035.

The convergence of the EGLE report's findings with the analysis presented in my testimony is significant. When EGLE, the state agency charged with climate planning, commissions a study reaching the same conclusions as I present in this testimony — that the gas system faces structural decline, that electrification is the primary decarbonization pathway, and that regulatory reform is necessary – it underscores that these are not speculative concerns but recognized realities of Michigan's energy landscape.

Q. What are the implications of these challenges for the Commission's review of DTE's rate case?

A. The convergence of rising costs, climate action, growing competition from alternatives, and declining population creates a fundamentally different planning environment than the one in which gas utility regulation was traditionally conducted. For decades, the gas system operated in a growth paradigm: new customers meant new revenue that helped cover system costs, and per-customer consumption was relatively stable. The four disruptors I have described are eroding each element of that paradigm.

This does not mean that the gas system will disappear by 2050. But it does mean that the Commission should apply increased scrutiny to DTE's proposed investments, particularly those that expand the system's reach and add long-lived assets to the rate base, to ensure that existing ratepayers are not bearing disproportionate risk from investments premised on optimistic assumptions about future gas demand. The Commission should also play a more significant role in gas system planning, as the MPSC has begun to do through the GDP process. The adequacy of DTE's planning in this regard is the subject of the next section of my testimony.

III. DTE IS NOT SUFFICIENTLY PLANNING FOR THESE CHALLENGES

Q. What did the Commission direct DTE to do regarding energy transition planning?

A. In its November 7, 2024 order in Case No. U-21291, the Commission found that "the transition away from fossil fuels and the eventual trend of declining natural gas demand will have impacts on the future of the natural gas system and that these impacts were not sufficiently considered in the company's GDP as filed."[26] The Commission directed DTE to file an updated Gas Delivery Plan demonstrating how it has "considered various energy transition pathways and the associated costs and risks of each." The Commission further directed DTE to address specific elements including: how the Company intends to achieve emissions reductions under both its corporate goals and the State's goals, with an estimated timeline; alternatives to capital investment, including pipeline repairs and non-pipeline alternatives; historical trends, projected demand, and impacts of changing demand; the projected impacts of the transition toward electrification and

[26] Case No. U-21291, Order, November 7, 2024, p. 216.

decarbonization, including the portions of its system that will be most immediately impacted; and meaningful engagement with interested persons.

Q. How has DTE responded to this directive?

A. DTE's response takes two forms. First, the Company filed an updated Gas Delivery Plan in Case No. U-21291, which is included in this case as Exhibit A-12, Schedule B5.6 and includes a seven-page section titled "Energy Transition." Second, Company Witness Decker's direct testimony addresses the GDP's energy transition content and describes the Company's climate-related strategies, including its positions on renewable natural gas, methane emissions reductions, and non-pipeline alternatives. Mr. Decker acknowledges the Commission's directive and claims that DTE has complied by including the Energy Transition section in the GDP.

Q. Has DTE adequately responded to the Commission's directive?

A. No. DTE has failed to plan for the challenges I described in the preceding section in two fundamental respects. First, the Company has not analyzed the financial consequences of declining gas demand for its ratepayers. In Section IV, I use a revenue requirement model to demonstrate that even modest declines in gas demand will materially increase costs for remaining ratepayers, and that more aggressive but plausible transition scenarios produce bill impacts that are unsustainable. Second, the Company's Gas Delivery Plan and supporting testimony do not satisfy the specific elements the Commission identified. I address deficiencies on methane mitigation, renewable natural gas, and non-pipeline alternatives in sections V, VI, and VII, respectively.

Q. Did DTE meaningfully engage stakeholders in the development of the GDP as the Commission directed?

A. The Commission directed DTE to "take steps to meaningfully engage interested persons in the development of its updated GDP." DTE's engagement was minimal. Discovery revealed that DTE held a single stakeholder meeting during the GDP development process and took no notes.[27]

Q. How should the Commission view these findings?

A. The Commission's 2024 order in Case No. U-21291 clearly stated that "the transition away from fossil fuels and the eventual trend of declining natural gas demand will have impacts on the future of the natural gas system and that these impacts were not sufficiently considered in the company's GDP as filed" and directed DTE to demonstrate a consideration of various energy transition pathways and their associated costs and risks. The record shows that DTE has not delivered on this directive. The absence of utility planning for these scenarios does not make the risk go away – it ensures that when change arrives, it arrives without mitigation. The Commission should require DTE to deliver on its 2024 directive and increase its scrutiny of future gas investments.

IV. INSIGHTS FROM REVENUE REQUIREMENT MODELING

Q. Have you analyzed the financial consequences of reduced gas demand for DTE Gas ratepayers?

A. Yes. I developed a simplified revenue requirement model for DTE Gas that projects delivery costs, residential bills, and per-customer infrastructure costs through 2050 under a range of demand scenarios. The model replicates standard utility revenue requirement methodology using DTE's own capital expenditure data from its Gas Delivery Plan, P-522 annual reports filed with the Commission, and authorized financial parameters from

[27] Exhibit AA-39. DTE Gas Response to MECCUBDG-3.16g.

recent rate proceedings.[28] The model's baseline results are independently corroborated by a separate analysis prepared by DHInfrastructure for the Citizens Utility Board of Michigan, which projected a nearly identical 2050 monthly residential bill of $177.22 under comparable assumptions.[29] This model is provided in Exhibit AA-31.

Q. What scenarios did you model?

A. I modeled seven core scenarios spanning the range of plausible futures for the gas system. Two scenarios provide alternative baselines: one with a continuation of DTE's projected growth in customer base, and one with a flat customer base. Scenario 1 assumes 4% customer attrition by 2050, a number that corresponds to Ann Arbor's current share of DTE Gas customers. Scenario 2 assumes that all DTE customers adopt hybrid heating systems to reduce gas consumption. Scenarios 3-6 model alternative pathways to decarbonizing today's gas heating by 2050: one with a combination of customer attrition, hybrid heating, and RNG; one with an equal mix of electrification and RNG; one with 100% electrification; and one with 100% RNG.

These scenarios vary across four dimensions: per-customer consumption trends, customer count trajectories, capital expenditure growth rates, and commodity cost assumptions. Table 1 summarizes the core assumptions defining each scenario.

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[28] The model uses a depreciation rate of 2.79%, weighted average cost of capital of 8.78%, retirement rate of 0.89%, and property tax rate of 1.17%, consistent with DTE's most recent filings. Operating costs are inflated at 2.3% per year based on CBO CPI-U projections.

[29] Investor-Owned Utility Gas Distribution Capital Expenditure A Study on the Potential Bill Impacts of Business-as-Usual Investment in Michigan, prepared by DHInfrastructure for Citizens Utility Board of Michigan (March 2025) (Relevant excerpt at Exhibit AA-40).

Table 1. *Revenue Requirement Model Scenario Assumptions*

Scenario	Demand Decline	Customer Trend	CAPEX Growth	Commodity
0A: Baseline w/ Growth	-1%/yr	DTE-projected growth	GDP values 2025-2035, then tracks inflation	Conv. gas
0B: Baseline w/o Growth	-1%/yr	Flat	GDP values 2025-2035, then tracks inflation	Conv. gas
1: Mild Decline	[Same as baseline]	-4% over 25 yr	[Same as baseline]	Conv. gas
2: Hybrid Heating	-3%/yr	Flat	[Same as baseline]	Conv. gas
3: Mild Decline + Hybrid Heating + RNG	-3%/yr	-4% over 25 yr	[Same as baseline]	RNG blend
4: 50% Electrification, 50% RNG	[Same as baseline]	-50% over 25 yr	GDP values 2025-2035, then flat	50% RNG
5: 100% Electrification	[Same as baseline]	-50% by 2040 and -100% by 2050	GDP values 2025-2035, then flat	Conv. gas
6: 100% RNG	[Same as baseline]	Flat	[Same as baseline]	100% RNG

The model is very sensitive to assumptions regarding inflation and relative growth in costs among different categories. The analysis was conducted in nominal terms to ensure consistency with historical data and the nominal basis of the WACC. Results were then deflated using a 2.3% compounded inflation rate to convert them to 2025 dollars. Ultimately, the key drivers of costs remain increasing infrastructure spending, the concentration of costs on remaining customers, and the high cost of renewable natural gas. The analysis is used to demonstrate these cost drivers.

Q. What do the baseline scenarios show?

A. Even under the most favorable assumptions, real monthly residential gas bills increase. Under Scenario 0A, which assumes DTE's own customer growth projections continue to materialize, real monthly bills (in 2025 dollars) rise from $96 in 2025 to $110 in 2050. However, customers see more significant impacts if that assumption changes. If customer growth stalls (Scenario 0B), bills rise to $127, or 15% above the growth baseline. Under

Scenario 1, which assumes a mild decline of just 4% of the customer base over 25 years, bills reach $131—a 36% increase, or a 19% premium over the growth baseline. Table 2 presents the real monthly bill projections for these baseline-adjacent scenarios.

Table 2. *Real Monthly Residential Bills (2025$) – Baseline Scenarios*

Year	Scenario 0A: Baseline w/ Growth	Scenario 0B: Baseline w/o Growth	Scenario 1: Mild Decline
2025	$96.18	$96.18	$96.18
2030	$103.37	$106.54	$107.13
2035	$107.97	$114.26	$115.60
2040	$110.45	$120.16	$122.37
2045	$111.07	$124.30	$127.46
2050	$110.28	$127.02	$131.17

These results demonstrate that without proactive planning, even a flat or modest decline in customer base will drive up the bills of remaining gas ratepayers. As I detail in section II of my testimony, these declines could be caused by a variety of factors including growing gas infrastructure costs, programs and legislation in support of state and local climate goals, increasing technology competition and customer preferences, and population decline.

Q. What happens under scenarios that reflect climate action or accelerated electrification?

A. Without proactive planning efforts, remaining gas customers face sharply escalating bills under any climate-aligned scenario. Under Scenario 5, which models a transition to full electrification by 2050, real monthly bills rise from $96 in 2025 to $393 by 2045 – more than quadrupling over that timeframe. Under Scenario 3, which pairs modest customer attrition with hybrid systems and RNG commodity costs, bills reach $275 by 2050, or 149% above baseline.

Table 3. *Real Monthly Residential Bills (2025$) – Climate-Action Scenarios*

Year	Scenario 3: Mild Decline + Hybrid + RNG	Scenario 4: 50% Elec + 50% RNG	Scenario 5: 100% Electrification	Scenario 6: 100% RNG
2025	$96.18	$96.18	$96.18	$96.18
2030	$113.24	$124.49	$121.15	$169.60
2035	$140.22	$194.84	$155.48	$234.20
2040	$172.25	$242.35	$207.43	$291.25
2045	$262.05	$288.98	$392.96	$341.24
2050	$275.07	$337.88	N/A	$384.91

Per-customer infrastructure costs escalate most dramatically under Scenario 5, where the remaining customer base shrinks to approximately 312,000 by 2045, and each bears a real annual distribution cost of $4,370 – a 343% premium over the growth baseline. Over this time, costs per therm delivered begin to exceed those of delivered fuels.

Q. Does RNG offer a path to mitigate these cost pressures?

A. No. RNG commodity costs rise rapidly across all blending scenarios. Our analysis incorporates price curves developed for the Michigan Renewable Gas Study, which show steep price increases as more RNG is consumed.[30] The comparison with Scenario 5 is particularly instructive: even under unmanaged full electrification, where 50% of customers depart the system over 15 years, remaining gas customers face lower monthly bills than under 100% RNG. This demonstrates that even the most disruptive electrification scenario produces better outcomes for remaining gas customers than RNG-based decarbonization. I detail additional concerns with RNG as a proposed solution to gas system decarbonization in Section VI of my testimony.

Q. What about hybrid heating, which DTE has promoted as a lower-cost alternative?

[30] Michigan Renewable Natural Gas Study, prepared by I.C.F. Resources, L.L.C. for the Michigan Public Service Commission (Sept. 23, 2022) (Relevant excerpts at Exhibit AA-41).

A. Hybrid heating that still relies on gas infrastructure but reduces gas consumption also creates a cost concentration situation. Assuming that per-customer demand decreases by 75% in hybrid heated homes does reduce gas utility bills—but this benefit yields just a 9% bill savings in 2050 compared to a baseline scenario. This happens because per-therm delivery costs increase 158% in real terms by 2050 under hybrid deployment (Scenario 2), a 111% incremental increase over the baseline scenario.

The fundamental reason for this trend is that reduced per-customer consumption does not proportionally reduce the fixed infrastructure costs embedded in gas delivery rates. Customers operating two heating systems continue to bear both the ongoing gas infrastructure costs and the capital cost of heat pump installation, making the net economic impact more adverse than gas bill figures alone suggest. In other words, while any individual customer could realize value from converting to a hybrid system today, the benefits of this strategy are almost completely diluted as system-wide deployment forces DTE to raise rates to meet its revenue requirements. This could potentially reach levels that exceed propane costs, leading savvy customers to further opt out of the gas system. This model demonstrates that, while a hybrid strategy reduces emissions, it exacerbates the cost concentration challenges.

Q. What does your model suggest about the potential impact of more proactive planning efforts to prepare for reduced demand scenarios?

A. While more precise modeling of the impact of proactive planning for gas system decline would require collaboration with DTE, my analysis demonstrates that proactive planning and management efforts have the power to materially reduce the cost burden on remaining customers. Under a 100% electrification scenario, remaining customers would save $31 per month in real terms by 2045 (an 8% reduction) if DTE's capital additions decline at 5% per year after 2035. Remaining customers see $92 per month savings (24%) in a more aggressive management scenario where DTE holds capital expenditures at 2025 levels through 2035 and then reduces them 5% annually afterward. These results show that the Commission's capital expenditure decisions today directly determine how costly the energy transition will be for the customers who remain on the gas system.

Q. What is the significance of these projections for the Commission?

A. Four findings are critical from this analysis. First, even a static customer base or a modest decline in customer base can have measurable negative impacts for gas ratepayers. Second, any foreseeable path toward reducing gas usage will lead to cost increases for gas ratepayers without proactive planning. Third, both RNG and hybrid heating increase customer costs, potentially leading to customer defection. Fourth, proactive planning and management can materially reduce the cost burden on remaining customers.

The financial consequences of gas system disruption are not a mystery. The delivery of gas relies on large, fixed-cost assets that are financed by spreading those costs across high consumption volumes over annual utilization and decade-long customer commitment periods. If that annual usage pattern changes or customers leave the system, those fixed costs become concentrated on remaining customers. The scenarios I model apply straightforward revenue-requirement analysis to a range of demand trajectories that span from DTE's own planning assumptions to outcomes consistent with declining gas usage (and Michigan's climate objectives). It is not possible to know what Michigan's gas system will look like in 2050—but prudent business practice demands consideration of all potential outcomes. The results of my analysis demonstrate the importance of the

Commission's 2024 order to assess the impacts of declining demand on DTE's business. Given the various headwinds facing DTE Gas in the near future, it is imperative that the Commission have the information necessary to weigh proposed DTE investments in light of the risks of declining demand.

V. LIMITATIONS OF METHANE MITIGATION

Q. What claims does DTE Gas make regarding its methane mitigation efforts?

A. DTE Gas claims significant progress in reducing its internal ("Scope 1") emissions. In the direct testimony of Company Witness H.J. Decker, DTE Gas states that it has "reduced the majority of its internal emissions via methane leak reductions, which the Company has primarily achieved through replacing leak-prone pipe with modern plastic via the Company's Gas Renewal Plan."[31] The GDP further claims a 44 percent reduction in annual Scope 1 emissions attributed to distribution mains and services since 2011, amounting to approximately 269,000 metric tons of CO_2e.[32]

Q. How does DTE Gas calculate these claimed Scope 1 emissions reductions?

A. DTE Gas calculates Scope 1 emissions for distribution mains and services "in accordance with the Greenhouse Gas Mandatory Reporting Rule as specified in 40 CFR Part 98 Subpart W."[33] The Company's own GDP acknowledges in a footnote that "DTE does not use direct measurement to determine the Scope 1 Emissions for this category; rather, they utilize the total miles, type of pipe, and emission factors to determine the emission

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[31] Decker, Direct Testimony, p. 8.
[32] Exhibit A-12, Schedule B5.6, p. 6.
[33] *Id.* at 82.

quantity."[34] I will address this "emissions factor" approach[35] below, noting that DTE's claimed emissions reductions are based entirely on changes in pipe material inventory, not on observed or measured reductions in methane reaching the atmosphere.

Q. Does DTE Gas also suggest that its Gas Renewal Program could be accelerated to achieve even greater emissions reductions?

A. Yes. Witness Decker testifies that "although the Company believes it is on track to meet its internal (Scope 1) emission reduction target, this target could be achieved sooner with an accelerated, or increased, Gas Renewal Program."[36] This statement is notable because it uses claimed emissions reductions as an additional justification for increased capital expenditure on pipe replacement. Again, these claimed reductions are based on emissions factors rather than direct measurement; the actual climate benefit of such acceleration is uncertain and may be substantially overstated. Moreover, DTE admits that the climate impacts are not a factor in determining what pipelines are repaired.[37]

Q. What are the key characteristics of methane as a greenhouse gas that are relevant to evaluating DTE's claims?

A. Methane (CH_4) is a short-lived but potent greenhouse gas. On a per-molecule basis, methane has a greater warming effect than carbon dioxide (CO_2), but this effect fades rapidly. Methane contributes to intense warming for roughly a decade before decaying in the atmosphere, whereas CO_2, once emitted, mostly persists for centuries.

The standard comparison tool is the Global Warming Potential ("GWP"), which

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[34] *Id.*
[35] For example, methane emissions are calculated as the product of the miles of pipe and a material-based per-mile emissions factor.
[36] Decker, Direct Testimony, p. 8.
[37] *See*, Exhibit AA-42. AADG 1.6.

compares the impacts of different greenhouse gases over a defined timescale, typically 20 or 100 years. Standard GWP values have been regularly updated with each successive Intergovernmental Panel on Climate Change Assessment Report. For instance, DTE's own GDP notes that "in 2024, the Global Warming Potential emission factor for the methane component increased thus causing an arbitrary increase in carbon dioxide equivalent emissions despite the methane emissions continuing to decrease."[38] This statement reveals an important point: when the metric used to convert methane to CO_2e changes, the Company's reported emissions change even if physical methane volumes remain constant. Such a change is not "arbitrary" – it reflects improving scientific understanding to inform decision-making. The next several questions will address how the scientific understanding of methane leaks is improving.

Q. How do methane leaks occur in a gas distribution system?

A. Methane escapes from the gas distribution system through leaks in mains and service lines, meter and regulator stations, customer meters, post-meter equipment, and during maintenance activities such as blowdowns. The rate of leakage from distribution pipe depends on several factors, including: pipe material (older cast iron and bare steel pipes have higher leak rates than modern plastic); pipe age and installation date; soil conditions (including corrosivity, moisture content, and ground movement); operating pressure within the system; temperature fluctuations; the quality of pipe joints and fittings; maintenance history; and external factors like construction activity. Not all these influencing attributes are captured by the standard emissions factors that DTE uses to calculate its claimed reductions.

[38] Exhibit A-12, Schedule B5.6, p. 82, fn. 1.

Q. What is the relative significance of methane leaks compared to other gas system emissions?

A. Estimated methane emissions from gas distribution systems are a relatively small component of the total greenhouse gas footprint associated with natural gas service. For example, the GDP implies that in 2024 fugitive methane emissions were 342 thousand tons CO_2e. Emissions from the combustion of DTE's delivered gas in 2024 were approximately 7.3 million tons CO_2e.[39] The emissions from customer combustion of natural gas represent the overwhelming majority of the climate impact of the gas system.

Q. What are emissions factors, and how are they used to estimate methane emissions from gas distribution systems?

A. Emission factors are standardized multiplier coefficients that assign a rate of methane emissions per unit of infrastructure, typically per mile of main or per service line, based on the pipe's material classification. These factors were derived from sampling studies and represent average emissions across a population of pipes of each material type. They do not reflect the actual emissions from any specific pipe segment.

Q. Are these emission factors accurate representations of actual methane emissions from individual pipe segments?

A. No. There is a fundamental difference between the certainty of emissions estimates derived from gas consumption (CO_2 from combustion) and those estimated from infrastructure inventories (fugitive CH_4). Calculating combustion emissions is straightforward: CO_2 emissions per unit of energy are predictable and consistent, and gas

[39] Based on combined sales of 137 BCF to conventional and Customer Choice customers in 2024 as reported in MPSC Form P-522 (Pages 305B and 306C, excerpted at Exhibit AA-43).

consumption is precisely metered. In contrast, quantifying fugitive methane emissions from leaky pipes is subject to considerable uncertainty. Leaks are stochastic. They occur irregularly throughout the system, can vary widely in size, and are influenced by multiple interacting factors that change over both seasonal and multi-year time scales.

A critical issue is the role of "super-emitters" which are a small number of leaks that are responsible for a disproportionate share of total emissions. Methane emissions follow extreme ("fat-tailed") distributions. Under such a distribution, the bulk of methane emissions is driven by abnormal conditions.

Such distributions are observed in DTE's service territory. In 2021, researchers from the University of Michigan School of Public Health deployed a mobile monitoring laboratory equipped with high-sensitivity Picarro CH_4 analyzers across southwest Detroit as part of the Michigan-Ontario Ozone Source Experiment (MOOSE).[40] Over 20 sampling days and approximately 1,100 km of driving, the researchers detected 534 distinct methane peaks, roughly one elevated reading every two kilometers. Nine locations showed repeated large peaks across multiple sampling days, suggesting sizable, persistent pipeline leaks or other concentrated CH_4 sources. The study area encompassed a mix of residential, commercial, and industrial land uses served by DTE's gas distribution infrastructure. These direct measurements from DTE's own service territory underscore why factor-based emissions estimates, which assume uniform leak rates across pipe categories, cannot reliably characterize actual methane emissions from a complex urban distribution system.

[40] Exhibit AA-44.

Q. What does this variability mean for the accuracy of DTE's claimed emissions reductions?

A. It means that DTE's claimed 44 percent reduction in Scope 1 emissions from distribution mains and services may not correspond to an actual 44 percent reduction in methane reaching the atmosphere. Consider two segments of cast iron pipe: one with a large, active leak and one that does not leak. Under the emissions factor approach, both segments are assigned the same emissions based on their material classification and length. Replacing the non-leaking pipe receives full credit for eliminating its assigned emissions, even though it was not contributing meaningful methane to the atmosphere. Replacing the actively leaking pipe receives the same credit, even though its actual emissions may have been many times higher than the factor assumed. Notably, non-replacement mitigation (patching, relining) does not receive any credit under this accounting approach.

Q. Has atmospheric monitoring confirmed that emissions-factor-based claims of reduction are accurate?

A. Evidence from other jurisdictions suggests caution toward a reliance on emissions factors. A 2021 study by Sargent et al.[41] found that total methane emissions in the Boston urban area were approximately six times higher than those estimated by bottom-up inventory methods (inclusive of behind-the-meter sources) over an eight-year study period, and showed no observable reduction in methane emissions during the first six years of an active pipe replacement program. While this study addressed a different gas system than DTE's, the fundamental measurement challenges are the same. The activity-

[41] Exhibit AA-45.

based emissions factors that DTE relies upon can be systematically wrong.

Q. Does DTE Gas acknowledge any limitations in its emissions accounting methodology?

A. The Company's GDP contains a notable footnote that partially acknowledges this issue: "DTE does not use direct measurement to determine the Scope 1 Emissions for this category, rather, they utilize the total miles, type of pipe, and emission factors to determine the emission quantity. In 2024, the Global Warming Potential emission factor for the methane component increased thus causing an arbitrary increase in carbon dioxide equivalent emissions despite the methane emissions continuing to decrease."[42] This footnote demonstrates that the Company's reported emissions are a function of regulatory accounting conventions rather than observed atmospheric conditions. The Company characterizes a GWP update as causing an "arbitrary" increase, yet the same accounting methodology underlies its claimed 44 percent reduction. If the Company considers updates to the GWP as "arbitrary," the Commission should consider whether the underlying factor-based methodology itself provides a reliable basis for assessing the climate benefits of the Gas Renewal Program.

Q. Are emissions factors likely to remain reliable over the long term, even as DTE replaces older pipe materials with modern plastic?

A. No. The premise of DTE's emissions accounting is that replacing cast iron, bare steel, and other legacy materials with modern plastic pipe results in a permanent reduction in fugitive methane emissions. But this framing assumes that plastic pipe is perfectly leak-free at install and does not develop leaks over time. That assumption is not supported by

[42] Exhibit A-12, Schedule B5.6, p. 81.

the evidence. While new plastic pipe has significantly lower average leak rates than aged cast iron or bare steel, plastic pipe is not immune to deterioration. Over the multi-decade service life of distribution infrastructure, soil movement, freeze-thaw cycles, and ground settlement can stress plastic pipe and its connections. The emissions factors used assign a fixed, low emission rate to plastic pipe and treat that rate as permanent. As the installed base of plastic pipe ages, actual emissions from those segments may diverge from the factors currently assigned to them, just as the factors assigned to older materials may not reflect actual leak conditions for any given pipe segment today.

This has a compounding effect on the reliability of DTE's claimed reductions over time. The Company's 44 percent Scope 1 reduction is calculated entirely from the difference between the emission factor assigned to removed pipe and the factor assigned to new plastic pipe. If the plastic factor understates long-term leak rates, the claimed reduction overstates the actual atmospheric benefit. The overstatement will grow with each year of aging. The fundamental problem is the same one that afflicts factor-based accounting for legacy materials: a statistical average applied to a pipe category cannot capture what is actually happening at any given location in the system. The emissions factor approach is not actionable and should have limited relevance in regulatory proceedings.

Q. Has direct measurement of methane been conducted in DTE's service territory, and what is the current state of DTE's own measurement capabilities?

A. Yes, direct measurement has been conducted. Independent researchers (discussed above) and DTE itself have deployed high-sensitivity Picarro CH_4 analyzers in the Detroit area, and their findings underscore the gap between factor-based accounting and actual field conditions. A similar leak measurement analysis was also performed in the Ann Arbor area and discussed in the prior rate case's testimony, which found similar results.[43] Notably, DTE Gas has operated the same Picarro technology since 2021 and is seeking $6.0 million in this proceeding to renew its Picarro Survey units. Company Witness Bolda testifies that Picarro "utilizes more sensitive gas detection technology (parts per billion vs parts per million), which has increased DTE Gas's ability to accurately identify existing leaks."[44] Witness Bolda further states that Picarro deployment "resulted in the identification and ultimately the remediation of hundreds of large emitting leaks in off-cycle survey areas that would have otherwise gone unidentified until the upcoming leak survey cycle." The Company also plans to use Picarro to conduct pre- and post-construction drives to compare area emissions before and after infrastructure replacement, "with the resulting decrease being attributed to the newly installed infrastructure and therefore supporting the effectiveness of the Gas Renewal Program."[45] DTE's own Picarro testimony is revealing in two respects. First, it confirms that traditional leak survey methods, the same methods underlying the Company's historical leak data, have systematically failed to identify large emitting leaks. Witness Bolda describes Picarro as transforming "the outdated manual process that is so dependent on human performance to identify leaks."[46] If DTE's prior survey methods missed hundreds of large leaks that Picarro subsequently found, then the historical leak data informing the Company's emissions factor calculations has been incomplete. Second, DTE's plan to use Picarro for pre- and post-construction emissions comparison represents an implicit

[43] Exhibit AA-46.
[44] Bolda, Direct Testimony, p. 27-28.
[45] *Id.* at 28.
[46] *Id.* at 27.

acknowledgment that direct measurement is necessary to verify whether pipe replacement actually reduces atmospheric methane.

Q. Given these findings, would investment in direct measurement and advanced mobile leak detection provide a more robust methane reduction strategy than the current emissions-factor-based approach?

A. Yes. The fundamental limitation of DTE's current approach is that it measures activity (miles of pipe replaced) rather than outcomes (methane actually prevented from reaching the atmosphere). A measurement-based strategy built around advanced mobile leak detection ("AMLD") technology and instruments like the Picarro analyzers used in the Batterman et al. study would enable DTE to identify and prioritize the specific locations that are actually emitting significant quantities of methane. This is a fundamentally different and superior approach because it: (1) identifies super-emitters; (2) is verifiable; and (3) is adaptive over time.

DTE's own Gas Delivery Plan states that the Company "has also invested in advanced leak detection equipment" and identifies "Advanced Leak Detection"[47] among the solutions it is considering to meet its 2040 and 2050 climate targets (and also make the system safer and more efficient by preventing fugitive methane). The Company should be commended for seeking to better understand leaks – acknowledging the limitations of conventional strategies. However, the contrast between DTE's current reliance on emission factors for its claimed 44 percent Scope 1 reduction and the availability of measurement technologies that have already been deployed in DTE's own service territory by independent researchers calls into question whether these techniques are

[47] Exhibit A-12, Schedule B5.6, p. 82.

successfully eliminating lost gas and the associated costs and climate impacts of methane emissions. Despite the improvement in data offered by AMLD, it still has some limitations. For example, it may be limited in the ability to quantify methane emissions or identify behind-the-meter leaks beyond the platform's field of view. Air-borne measurement may address some of these limitations, but may face other cost, measurement, and operational tradeoffs.

Q. What are the implications of these limitations for DTE's Gas Renewal Program as a strategy to prevent methane emissions?

A. The implications are significant. The emissions factor approach creates a systematic bias in favor of pipe replacement as the primary – and effectively sole – mechanism for demonstrating reductions in fugitive methane. Because the metric is based solely on pipe material, it does not recognize methane emissions reductions achieved through other means, such as direct leak repair, pipeline relining, or robotic joint sealing. A repair of a large leak on a cast-iron main would not be "credited" as a method to reduce methane emissions, while replacement of a non-leaking main would be assumed to be a literally perfect solution. This misalignment between accounting credit and actual emissions reduction is a fundamental flaw that creates a prejudice for new capital over improved maintenance.

Q. Is leak-prone pipe replacement a cost-effective strategy for reducing methane emissions?

A. When evaluated through the lens of mitigating methane leaks, pipe replacement is an extraordinarily expensive strategy that delivers uncertain emissions reductions. Assuming the emissions factors are representative, the cumulative social cost of methane leaked from a mile of cast-iron pipe over 20 years is on the order of $156,000, based on EPA's social cost of methane and standard emissions factors. The cost to replace that mile of pipe averages $1.6 million in DTE's territory. From a pure emissions mitigation perspective, the cost of pipe replacement far exceeds the climate damage it prevents. While the Gas Renewal Program serves legitimate safety purposes, its reductions in fugitive emissions (and the climate benefits) are incidental and provide no weight toward accelerated capital expenditure in lieu of more aggressive maintenance of existing infrastructure.

Q. What are your recommendations to the Commission regarding DTE's methane emissions claims and the Gas Renewal Program?

A. The uncertainty associated with how methane evolves within the gas system impedes quantification; it should not be used as a justification for delaying efforts to reduce actual emissions, especially at a time when detection technology is improving identification and classification, if not quantification. As implementers of such technology and custodians of methane-emitting assets, utilities such as DTE can play an important role in advancing effective methane mitigation strategies. To achieve this outcome, I offer the following recommendations:

First, the Commission should recognize that DTE's claimed Scope 1 emissions reductions are based on changes in pipe material inventory, not on measured or observed reductions in atmospheric methane. The Commission should afford these claims limited weight as evidence of a reduction in fugitive methane when evaluating the Gas Renewal Program and any proposals to accelerate it.

Second, if a reduction in lost gas is assumed as part of the cost justification for the program, the Commission should require support for that figure through use of a measurement technology, not a blanket assumption. For instance, more verifiable methods include advanced mobile leak detection (“AMLD”) or aerial survey methods—appropriate to its system. DTE should be required to propose and implement a pilot study covering a representative portion of its distribution system to establish baseline emissions data. Such data would provide the Commission with a more reliable basis for evaluating the actual climate impact of infrastructure investments.

Third, the Commission should require DTE Gas to develop and submit enhanced reporting on methane emissions, including: geocoded leak data with standardized formatting; summaries of leak repairs by material type and repair method employed (replacement, patching, relining, etc.); and, where AMLD or similar data become available, comparisons of estimated versus measured emissions. This information would support long-term tracking of actual emissions performance.

Fourth, given the high potency but short atmospheric lifetime of methane, and the fat-tailed distribution of emissions across the system, cost-effective methane leak mitigation should be targeted at the largest emitters rather than based on broad replacement of infrastructure by material type. Methane mitigation may be larger via non-replacement strategies, including advanced leak repair, pipeline relining, and robotic joint sealing. Such approaches can address the highest-emitting leaks, and thus reduce the cost impacts of lost gas, at a fraction of the cost of replacement of the pipes.

Fifth, the Commission should assess how the Company’s infrastructure investment strategy (e.g., the GRP) would impact ratepayers if overall gas consumption shrinks instead of grows. Pipe replacement in areas likely to be targeted for electrification or decommissioning may represent an imprudent investment. To minimize the risk of stranded costs to ratepayers, the Commission should both scrutinize proposals to add large amounts of capital to the system, and consider adjusting depreciation rates to mitigate for the risk of large future rate impacts from investments that appear reasonable and prudent today.

VI. <u>RENEWABLE NATURAL GAS</u>

Q. Please describe DTE Gas's interest in and use of Renewable Natural Gas ("RNG").

A. DTE Gas has identified RNG as a central element of its emissions-reduction strategy, both in its current operations and in its vision for meeting future climate requirements. The Company's engagement with RNG operates on two levels.

First, DTE Gas has established 21 operational interconnections with RNG producers across Michigan. The Gas Delivery Plan describes these efforts as part of DTE's broader investment in "actions beyond natural gas."[48] This section will highlight the fact that RNG production is limited and a poor use of bioenergy resources and that recent growth reflects distortive environmental attribution markets which the Commission should avoid further influencing.

Second, and more consequentially for this proceeding, DTE Gas presents RNG blending as the most cost-effective pathway for achieving deeper emissions reductions in the built environment. Witness Decker testifies that DTE Gas conducted "internal analysis on RNG blending" and concluded that "using RNG for 14% of a customer's usage reduced emissions nearly as much as full electrification when considering the carbon intensity of

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[48] Exhibit A-12, Schedule B5.6, p. 84.

the grid."[49] This section illustrates flaws in DTE's simplistic analysis here.

DTE's advocacy for RNG ignores the realities of the attractiveness and effectiveness of this strategy as a way to continue use of the current system in the face of increasing customer or regulatory pressures to decarbonize, and thus the importance of regulatory action to manage that increasing risk.

Q. What is Renewable Natural Gas?

A. Renewable Natural Gas is methane produced from biomass feedstocks[50] that is upgraded to pipeline quality and injected into the pipeline gas distribution system. The term "renewable" distinguishes it from fossil methane by its biogenic origin: the carbon in RNG was recently captured from the atmosphere through biological processes, rather than extracted from geological deposits. Importantly, however, the end-use combustion product is identical: both RNG and fossil gas produce CO_2 when burned in a furnace or boiler. The claimed climate benefit of RNG rests not on eliminating combustion emissions but on the need to use limited bioenergy resources to produce it.

Q. Is RNG a scalable decarbonization strategy for the building sector?

A. No. RNG is fundamentally limited by the availability of biomass feedstocks, which are constrained in quantity and face competing demands from higher-value applications. This is not a contested point; even industry-sponsored assessments acknowledge these limitations. The American Gas Foundation's 2025 Renewable Natural Gas Supply Assessment explicitly states that its feedstock inventory "does not estimate resource availability—in a competitive market, resource availability is a function of factors,

[49] Decker, Direct Testimony, p. 17.
[50] Landfills, wastewater treatment facilities, animal manure, and agricultural residues.

including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development."[51] This means that many forecasts of RNG availability make the tenuous assumption that feedstocks are solely available for RNG production and other uses such as electricity generation, sustainable aviation fuel, or carbon capture and sequestration.

Q. What do these constraints mean in the context of Michigan's resources?

A. The Michigan-specific evidence on scalability is particularly relevant to this proceeding. The Michigan Public Service Commission's own 2022 Renewable Natural Gas Study, prepared by ICF,[52] found that Michigan consumed an average of 673 trillion Btu (tBtu) of natural gas annually in the residential, commercial, industrial, and vehicle sectors from 2016 to 2020. Under ICF's "Achievable" scenario, which represents a low but realistic level of feedstock utilization, Michigan could produce only 57.2 tBtu of RNG per year by 2050, equivalent to just 8.5% of the state's average annual natural gas consumption. Even under the more aggressive "Feasible" scenario, which assumes higher feedstock utilization rates and the commercial deployment of thermal gasification technology not expected to be cost-competitive until the 2040–2050 timeframe, Michigan's RNG production would reach only 148 tBtu per year by 2050 (22% of current consumption). The theoretical maximum, utilizing 100% of all available feedstocks with no constraints, yields 313.4 tBtu; less than half of Michigan's current gas demand.

These figures have direct implications for DTE's RNG blending strategy. If even a 14%

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[51] Renewable Natural Gas Supply Assessment, prepared by ICF for American Gas Foundation (Jul. 2025) (Relevant excerpt at Exhibit AA-47).

[52] Michigan Renewable Natural Gas Study, prepared by I.C.F. Resources, L.L.C. for the Michigan Public Service Commission (Sept. 23, 2022) (Relevant excerpts at Exhibit AA-41).

blend rate across DTE's residential customer base were to be sourced from Michigan-produced RNG, it would consume a substantial share of the state's total achievable RNG production, leaving little or no supply for other gas utilities, commercial and industrial customers, or higher-value applications such as transportation fuel or electricity generation. The Commission's own study thus undermines the premise that RNG blending can serve as a meaningful, scalable strategy for the building sector.

Q. Are there other factors influencing the scalability of RNG?

A. Several additional characteristics make RNG poorly suited as a building decarbonization strategy at scale. First, RNG supply curves demonstrate increasing costs with growing consumption. Unlike solar panels or batteries, which benefit from manufacturing scale, biorefineries are constrained by feedstock availability and transportation distances. The MPSC's ICF study confirms this, showing RNG production costs ranging from less than $10/MMBtu for the most favorable landfill gas sites to upwards of $50/MMBtu for smaller or less favorable facilities, compared to commodity natural gas prices below $5/MMBtu.[53] Second, the current RNG market represents the lowest-cost feedstocks; growth requires tapping progressively more expensive sources, including energy crops that carry their own emissions from cultivation and land-use change. Third, and most importantly, limited bioenergy resources should be directed toward applications where electrification is not a viable alternative, such as sustainable aviation fuel, renewable diesel, marginal electricity generation, and high-temperature industrial processes. Pipeline RNG for building heat is an inferior use of these resources because electric heating is a mature and developed pathway; alternatively, few options exist for

[53] *Id.*

decarbonizing aviation beyond low-carbon fuels.

Multiple independent analyses—including industry-sponsored research—have consistently found RNG to be an inferior building decarbonization strategy. Studies conducted by the Low Carbon Resources Initiative, a joint effort of the Electric Power Research Institute and the Gas Technology Institute, showed negligible low-carbon fuel use in the building sector under most scenarios evaluated.[54] In nearly all "net zero" scenarios modeled, residual fossil gas in the building sector was preferred over RNG to manage remaining emissions—meaning it is more cost-effective to continue limited fossil gas use rather than incur the high cost of substituting RNG.

Q. DTE Gas highlights its 21 operational RNG interconnections as evidence of a growing market. What is driving this growth?

A. The growth of the RNG market (including DTE Gas's 21 interconnections) is largely driven by federal and state subsidy programs that create outsized financial incentives specifically for upgrading biogas to pipeline-quality RNG, while providing little or no comparable incentive for alternative uses of the same biogas feedstocks. These incentive structures place a thumb on the scale in favor of RNG over other, superior, uses of the same biological resource.

The two most influential programs are the Federal Renewable Fuel Standard ("RFS"), established in 2005, and the California Low Carbon Fuel Standard ("LCFS"), established in 2007. Both were explicitly designed to increase the adoption of low-carbon fuels at a time when the outlook for electric vehicles was far less favorable than it is today. RNG

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[54] Net-Zero Scenarios 2.0: Sensitivity Analysis and Updated Scenarios for LCRI Net-Zero 2050, prepared by EPRI (December 2024) (Relevant excerpt at Exhibit AA-48)

used as compressed natural gas in vehicles is an established compliance pathway under both programs. Critically, because these programs generate credits valued against the compliance costs of expensive liquid fuels, they create an enormous subsidy for RNG relative to the commodity cost of fossil methane. RNG attribute prices have at times exceeded $80 per MMBtu, while the commodity price of natural gas is below $5 per MMBtu. RNG producers can stack credits from both the RFS and the LCFS, compounding the subsidy.

A regrettable and unintended consequence of this market design is that it systematically favors the RNG pathway over electric uses of the same biogas. An RNG producer can earn both RFS and LCFS credits from a facility located anywhere in the United States. By contrast, a facility that burns the same biogas directly to generate electricity can only earn LCFS credits, and only if the facility is interconnected with the California electric grid. The RFS has never included an electric compliance pathway. This asymmetry is not a reflection of the relative environmental merits of the two pathways; it is an artifact of policy design that predates the modern era of competitive electric technologies.

The distortive effect of these incentives is visible in the development patterns of the broader biogas industry and is documented in the MPSC's own 2022 Michigan RNG Study. ICF found that Michigan's biogas-to-electricity investment slowed markedly after 2013, coinciding with the EPA's 2014 determination that RNG qualifies as an eligible renewable fuel under the RFS and the subsequent 2015 determination that landfill-sourced RNG qualifies as a cellulosic biofuel.[55] The ICF study documents a concrete

[55] Michigan Renewable Natural Gas Study, prepared by I.C.F. Resources, L.L.C. for the Michigan Public Service Commission (Sept. 23, 2022) (Relevant excerpts at Exhibit AA-41).

Michigan example of this market distortion: in February 2022, the City of Riverview voted to convert its Riverview Land Preserve—Michigan's oldest biogas-to-electricity project, operational since 1987—from electricity generation to RNG pipeline injection and use as a transportation fuel.[56] This trend is further depicted in Figure 2 using my analysis of EPA methane management project data.

[56] *Id.*

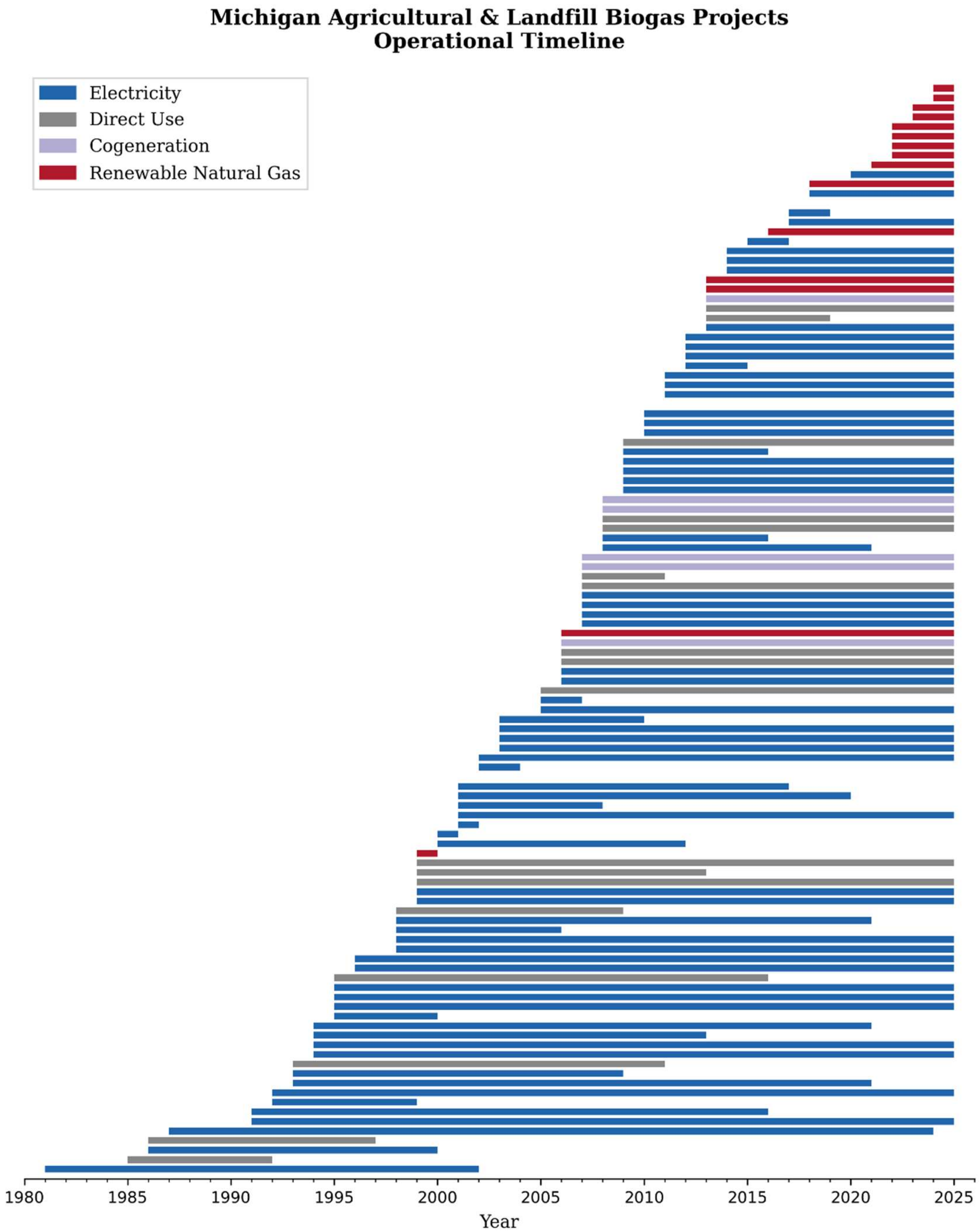

Figure 2. *Timeline of landfill or agricultural biogas energy projects in Michigan by energy product. Source: EPA AgSTAR Life Stock Anaerobic Digestion Database and Landfill Methane Outreach Program Database*

The American Biogas Council inventories over 2,200 biogas-producing sites in the United States. The vast majority of these are older facilities that produce heat or electricity through direct combustion of biogas. The roughly 338 pipeline-quality RNG facilities represent a much smaller subset, yet this is the segment that is growing, driven by the distortive financial incentives described above. Some of these new RNG facilities represent conversions of existing direct-burn electricity facilities, meaning the subsidy structure is pulling biogas away from electricity generation and toward pipeline injection. This dynamic was further illustrated in 2023 when the EPA explored developing an electric compliance pathway for the RFS. In response to this potential change, WM (formerly Waste Management) announced that it would maintain two landfill electricity generation sites rather than convert them to RNG as previously planned. The RNG Coalition and American Biogas Council supported the inclusion of an electric pathway. The proposal ultimately did not proceed, but WM's response demonstrates that development decisions in this sector are driven primarily by the subsidy structure rather than by the inherent environmental or economic merits of one pathway over another.[57] Therefore, when evaluating whether increased investments in the gas distribution system have risk mitigation due to the possibility of RNG blending to meet customer or regulatory demands, the Commission should recognize that RNG may not be available, especially if the tax credit structure is changed to eliminate this likely unintended consequence. The Commission should understand DTE Gas's 21 RNG interconnections in this context. These interconnections are not evidence that RNG is the most efficient or cost-effective use of Michigan's bioenergy resources. They are evidence that current federal and state incentive structures disproportionately reward pipeline injection of upgraded biogas while providing little or no comparable incentive for direct electricity

[57] Exhibit AA-49; Exhibit AA-50.

generation from biogas. DTE's characterization of these interconnections as reflecting a "commitment to sustainable energy solutions" obscures the role that distorted incentive structures play in driving these investment decisions. The RNG market is growing not because pipeline injection is the best use of biogas, but because it is heavily subsidized.

Q. Do other states that have evaluated RNG as a risk-mitigation factor find it to be attractive?

A. No. Notably, the NYS Energy Plan[58] and its technical support document, Considerations for Low-Carbon Alternative Fuel Use in New York State,[59] comprehensively evaluate renewable fuels across multiple sectors and take the position that pipeline RNG for building heat is an inferior use of limited bioenergy resources.

The Plan discusses how bioenergy feedstocks should be prioritized to specific fuels and end uses, noting the inferiority of pipeline RNG. The Plan's technical support document states: "Wastewater, for instance, may be able to produce RNG at a lower cost than [sustainable aviation fuel] or renewable diesel; however, injecting RNG into the gas distribution system does not directly advance the State's long-term goals, whereas using it to produce [sustainable aviation fuel] or renewable diesel does."[60] The Plan ultimately concludes that "Electrification should remain the first decarbonization solution and the use of low-carbon alternative fuels should be directed toward end-uses to maximize GHG emissions reductions while minimizing the cost of the energy transition, ensuring net co-pollutant emission reductions, and avoiding impacts associated with co-pollutant

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[58] Low-Carbon Alternative Fuels, New York State Energy Plan, Volume II Our Energy Systems (Dec. 16, 2025) (Relevant excerpt at Exhibit AA-51)

[59] Considerations for Low-Carbon Alternative Fuel Use in New York State, New York State Energy Research and Development Authority (July 2025) (Relevant excerpt at Exhibit AA-52)

[60] *Id.*

emissions"[61] and recommends designing infrastructure for liquid fuel production rather than pipeline injection, because liquid fuels serve higher-value applications with fewer alternatives.

Q. Does DTE's comparison of RNG and electrification reflect these concerns?

A. No. DTE's analysis relies on an RNG cost assumption that is not scalable and ignores its own commissioned data on supply constraints. The Company assumes an RNG cost of $18 per MMBtu. According to the Michigan Renewable Natural Gas Study commissioned by the MPSC, approximately 40 tBtu of RNG supply is available in Michigan at or below this price point. This represents approximately 4% of Michigan's total natural gas consumption. The study further identifies an "Achievable" production limit of 57.2 tBtu, beyond which costs rise sharply, reaching $50 per MMBtu or more for less favorable feedstocks. DTE's assumed price, therefore, reflects only the cheapest tranche of a severely supply-constrained resource.

Q. Are there other flaws with DTE's comparison of RNG and Electrification?

A. DTE's cost-effectiveness comparison is highly sensitive to the grid emissions forecast used to evaluate heat pump performance. The Company's analysis[62] uses a conservative MISO PROMOD forecast that assigns high carbon intensity to grid electricity, making heat pumps appear less effective at reducing emissions than they will be in the future under both Michigan's historical trend and new regulatory requirements. However, climate-conscious customers are already showing a nationwide attraction for heat pumps and less of an attraction for RNG.

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[61] Low-Carbon Alternative Fuels, New York State Energy Plan, Volume II Our Energy Systems (Dec. 16, 2025) (Relevant excerpt at Exhibit AA-51).

[62] Exhibit AA-53.

DTE's own model workbook contains an alternative scenario — labeled "DTE Environmental Target"[63] that reflects grid decarbonization consistent with Michigan's clean energy trajectory, including the requirements of Public Act 235 of 2023. DTE does not explain why it disregards this scenario in favor of the more pessimistic forecast regarding the effectiveness of heat pumps for customers who wish to decarbonize. Electrification becomes more effective as an emissions-reduction strategy as the electric grid decarbonizes, and Michigan law now requires that it do so. Using a grid forecast that ignores these requirements systematically understates the emissions benefit of electrification and overstates the relative attractiveness of RNG for climate-conscious customers or as a likely pathway for future regulatory compliance. When the analysis is corrected using DTE's own "DTE Environmental Target" scenario, heat pump electrification achieves an estimated 63% reduction in heating-related emissions. While DTE makes conservative assumptions for electrification, it treats emissions reductions from RNG uncritically. DTE's analysis assumes zero greenhouse gas intensity for RNG, but the energy required for biogas purification results in an effective emissions intensity of approximately 0.015 tons of CO_2 per MMBtu, reducing RNG's climate benefit to roughly 72% of the Company's claimed value. Correcting for this factor would require approximately 38% more RNG to achieve the same emissions reductions using the MISO PROMOD forecast, further straining an already constrained supply and increasing costs proportionally of a disfavored mitigation pathway.

Q. Does DTE's climate strategy also rely on hydrogen blending or carbon offsets?

A. Yes. DTE's Gas Delivery Plan identifies hydrogen blending and offsets among the

[63] Exhibit AA-54.

strategies it is considering to meet its longer-term climate targets, but does not provide any material detail for how these will play a role.

Q. What are your recommendations regarding DTE Gas's RNG claims?

A. The Commission should not assume RNG use will mitigate the risks associated with DTE's proposals for increased investment in the existing gas distribution system.

VII. NON-PIPELINE ALTERNATIVES

Q. How does DTE Gas characterize non-pipeline alternatives in this proceeding?

A. In his direct testimony, DTE Gas Witness Decker dismisses non-pipeline alternatives as limited to "niche projects" that are not scalable.[64] Specifically, Mr. Decker cites a single study co-authored by National Grid and RMI examining nine NPA cases across the United States and Europe,[65] and concludes that NPAs are "only truly effective in niche projects 'serving 1-5 customers, under the 100% persuasion model.'"[66] Based on this characterization, Mr. Decker testifies that "DTE Gas does not foresee a material impact on the need for natural gas infrastructure in realistic electrification scenarios."[67]

Mr. Decker's characterization of NPAs is incomplete, outdated, and misleading in several respects. First, the National Grid-RMI report Mr. Decker cites was published in May 2024, and the NPA landscape has evolved substantially since that time. Since that publication, Massachusetts has established a comprehensive NPA evaluation framework requiring all gas capital investments to be screened for NPA viability;[68] California has

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[64] Decker, Direct Testimony, p. 19.

[65] Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization, RMI and National Grid (May 2024) (Executive Summary at Exhibit AA-55)

[66] Decker, Direct Testimony, p. 19

[67] *Id.*

[68] Massachusetts Department of Public Utilities, Order 20-80-B, December 2023.

enacted Senate Bill 1221, authorizing up to 30 targeted electrification pilot projects;[69] Colorado has selected five gas planning pilot communities;[70] and Consolidated Edison in New York has implemented its Energy Exchange Program offering $10,000–$20,000 per customer for electrification of customers served by pre-1971 service connections.[71]

Second, the National Grid-RMI report itself does not conclude that NPAs should be abandoned – it concludes that the *approach* to NPAs must evolve beyond individual customer persuasion toward utility-led, system-level planning.[72] The report identifies systemic barriers to scaling, including the lack of utility incentive structures and the absence of holistic gas system planning—barriers that other states are now actively addressing through the programs I describe below.

Third, and most importantly, Mr. Decker's testimony fails to acknowledge the fundamental reason NPAs are receiving increasing attention in other jurisdictions: the growing recognition that continued investment in gas infrastructure carries significant asset continuation risk: the risk that ratepayers will bear the cost of infrastructure that does not generate sufficient revenue over its useful life.

Q. What is a non-pipeline alternative?

A. A non-pipeline alternative is an investment or set of measures that enables a gas utility to avoid, defer, or reduce a traditional pipeline infrastructure project – such as main replacement, main extension, or system reinforcement – by reducing or eliminating gas demand on a targeted segment of the distribution system. The concept is analogous to

[69] California Senate Bill 1221 (2024).
[70] *See*, Colorado House Bill 24-1370.
[71] *See*, ConEdison, Energy Exchange Program.
[72] Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization, RMI and National Grid (May 2024) (Executive Summary at Exhibit AA-55)

demand-side management on the electric system, or to "non-wires alternatives" that electric utilities use to defer transmission and distribution investments. DTE Gas's own Gas Delivery Plan acknowledges that "some utilities, such as those in New York, are emphasizing Non-Pipeline Alternatives (NPAs) in areas where system constraints require new capital investment" and defines NPAs as "alternative investments that allow a utility to eliminate or delay the implementation of a traditional pipeline project."[73]

NPAs can take several forms: they may involve converting all customers on a targeted pipe segment to alternative heating sources, thereby enabling the utility to retire the pipe rather than replace it; they may involve reducing demand on a constrained segment sufficiently to avoid a reinforcement project; or they may involve avoiding the extension of gas mains to serve new development by ensuring that development is served by electric alternatives from the outset.

In DTE Gas's service territory, the most relevant NPA applications involve avoiding or deferring capital expenditures for main replacement and new customer extensions by transitioning customers to alternative heating technologies such as heat pumps, or hybrid heating arrangements with delivered fuels.

Q. What cost and risk dynamics do non-pipeline alternatives address?

A. NPAs address two interrelated economic concerns that are central to the long-term interests of DTE Gas ratepayers: transition costs and asset continuation risk.

Transition cost refers to the net investment required to enable a gas system segment to be retired rather than replaced. This includes the cost of customer-side measures – electrification equipment, building upgrades, delivered fuel conversion, or other

[73] Exhibit A-12, Schedule B5.6, p. 85–86.

alternatives – minus the avoided cost of the pipeline infrastructure investment that would otherwise occur. Transition costs can be positive, when customer-side investment exceeds avoided infrastructure costs, or negative, when avoiding the infrastructure generates net savings. Transition costs can be assessed in upfront capital terms or from a longer-term net-present-value perspective that incorporates ongoing energy costs and other utility costs.

Asset continuation risk refers to the cost borne by ratepayers of continuing to invest in and maintain infrastructure that may not generate sufficient revenue over its useful life relative to a counterfactual in which it is retired and not replaced. This risk arises when expensive infrastructure serves customers who may reduce or eliminate their gas consumption within the investment's useful life. The costs of that infrastructure do not disappear when customers depart the system. They are reallocated to remaining ratepayers through the ratemaking process, creating a cycle of rising rates and further customer departures.

These two concepts interact in important ways. A segment with high asset continuation risk may justify accepting higher transition costs, because avoiding the infrastructure also avoids the ongoing risk of cost concentration on remaining ratepayers. Conversely, a segment with low asset continuation risk may not warrant NPA investment even where technically feasible, because the infrastructure is likely to remain well-utilized throughout its useful life.

Q. How are other states approaching non-pipeline alternatives?

A. Several states have moved well beyond the conceptual stage and are implementing NPA programs of direct relevance to Michigan. I highlight three that illustrate the range of approaches.

Consolidated Edison (New York). Con Edison operates 4,500 miles of gas mains serving 1.1 million gas customers in New York City and Westchester County. The utility spends approximately $400 million annually to replace approximately 1,200 miles of leak-prone pipe installed before 1972. Con Edison has developed two NPA programs of particular relevance. First, its "Electric Advantage Program" eliminates select main replacement investments by electrifying all affected customers on a targeted segment. Second, its "Energy Exchange Program" offers individual customers served by pre-1971 service connections electrification incentives of $10,000–$20,000, tiered by building type and disadvantaged community status. Con Edison recovers NPA costs as a regulatory asset, and utilizes a performance incentive structure that makes NPA investment revenue-neutral or preferable for the utility.

Massachusetts NPA Framework. In December 2023, the Massachusetts Department of Public Utilities issued Order 20-80-B, establishing that all gas capital investments must be evaluated for an NPA prior to proceeding. In April 2025, the state's Local Distribution Companies filed Climate Compliance Plans with proposed NPA frameworks that include a sequential gated evaluation process: initial viability screening, gas system integrity review, customer viability assessment, electric system review, and benefit-cost analysis. National Grid filed a Targeted Electrification Demonstration Program Implementation Plan (Massachusetts D.P.U. 24-194) proposing to cover 100% of customer conversion costs and provide bill credits to offset differential operating costs. Four additional gas utilities are filing pilot proposals. The Massachusetts legislature has also adopted changes to the obligation to serve that allow utilities to "vary the uniformity of service," providing legal authority for managed transitions.

Targeted Electrification Pilots (California and Colorado). California enacted Senate Bill 1221 in 2024, establishing a framework for neighborhood-scale decarbonization including authorization for up to 30 pilot projects for gas decommissioning coordinated with building electrification. The law requires gas utilities to publish maps of pipeline replacement projects that could be candidates for targeted electrification. In Colorado, House Bill 24-1370 directed the Colorado Energy Office to solicit interest from municipalities in becoming "gas planning pilot communities." Five communities were selected in 2025, and Xcel Energy proposed the "Mountain Energy Project," described as the largest at-scale NPA portfolio in the United States, affecting approximately 33,500 customers with a projected cost savings of approximately $170 million compared to the traditional pipeline approach.

The common thread across these states is recognition that the question is no longer whether NPAs are viable, but how to source, evaluate, and implement them systematically. DTE Gas's position that NPAs are limited to niche projects is increasingly at odds with the direction of utility regulation nationally.

Q. How should DTE Gas identify and source NPA opportunities on its system?

A. Effective NPA sourcing requires a long-term, systematic approach to limiting new investment in the gas system and identifying segments where infrastructure avoidance is both feasible and cost-effective. The National Grid-RMI report that Mr. Decker cites recommends that utilities proactively and systematically scan their asset bases for favorable areas for gas decommissioning.[74] I recommend three elements.

First, NPA identification must be embedded in long-term gas system planning, not treated as an ad hoc response to individual projects. The fundamental question is: how does DTE Gas limit future investment in the gas system in a manner that protects ratepayers from asset continuation risk? This requires the Company to evaluate its entire system, not just individual project proposals, to identify where infrastructure avoidance yields the greatest benefit. Currently, DTE Gas's Gas Delivery Plan evaluates capital investments project-by-project without a holistic assessment of how those investments interact with the long-term trajectory of gas demand and the risk of underutilization.

Second, DTE Gas should conduct a holistic gas system analysis to identify severable, leak-prone pipe segments (including service lines) that are candidates for retirement rather than replacement. This analysis should evaluate the hydraulic severability of pipe segments (i.e., whether a segment can be retired without compromising service to remaining customers), the condition and leak history of the pipe, the cost of replacement versus the transition cost of converting affected customers, and the number and characteristics of customers served. The results of this analysis should be shared with the Commission in the form of detailed maps and data that enable the Commission and intervenors to evaluate the Company's capital investment decisions in the context of NPA potential.

Third, DTE Gas should analyze the potential for individual customer conversions to contribute to broader infrastructure avoidance opportunities. Even where a full segment-

[74] Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization, RMI and National Grid (May 2024) (Executive Summary at Exhibit AA-55)

level NPA is not immediately feasible, individual customer departures from a targeted segment can improve the economics of future retirement by reducing remaining load. A customer departing a pipe segment reduces the revenue that segment must generate, but also reduces the demand that must be served, which may render the segment hydraulically severable in the future. Con Edison's Energy Exchange Program takes this approach: by offering individual customers on aging service connections incentives to electrify, the utility reduces the number of service connections requiring replacement and brings targeted main segments closer to retirement eligibility. DTE Gas should evaluate which segments of its system are approaching a tipping point where modest customer reductions would enable infrastructure avoidance.

Q. How should customers be involved in NPA planning?

A. Successful NPA implementation depends fundamentally on customer participation, which in turn depends on customer access to information about the gas system and the costs they face. Customers cannot make informed decisions about their energy future if they do not understand the trajectory of the gas system that serves them.

DTE Gas should publish gas system data that indicates to customers the condition of the infrastructure serving their properties and the planned capital investments in their area. This should include, at minimum, the age and material of the pipe serving their neighborhood, whether the pipe is scheduled for replacement or major maintenance, the expected cost of that work and its impact on delivery rates, and whether the segment has been identified as an NPA candidate. This information should be provided through a publicly accessible web portal and map interface.

Transparency about gas system conditions serves two purposes. First, it enables customers to evaluate their own options with full knowledge of the costs and risks associated with each path. Second, it enables third-party organizations, municipalities, and community groups to identify NPA opportunities and facilitate customer participation. The experience in other states has shown that utility-controlled NPA identification, without external input, tends to be conservative and slow. Transparent data enables a broader set of actors to participate in identifying and advancing cost-effective alternatives.

Q. Do you have additional recommendations for how NPA efforts should begin?

A. I recommend that the Commission direct DTE Gas to publish maps identifying customers served by leak-prone pipe, including pipe age, material, condition, and planned replacement timeline. These maps should be made available through a publicly accessible web portal and should include sufficient detail for the Commission, intervenors, municipalities, and customers to identify potential NPA opportunities. The maps should be updated regularly as part of the Company's Gas Delivery Plan filing. Publication of this data is a prerequisite for meaningful NPA evaluation and is consistent with the direction of regulatory proceedings in New York, Massachusetts, California, and Illinois. Without this information, the Commission and stakeholders cannot evaluate whether DTE Gas's capital investment program is prudent in light of available alternatives.

VIII. EXISTING CUSTOMERS BEAR THE RISK OF NEW CUSTOMERS

VIII-A. Overview of DTE Gas's Customer Attachment Program

Q. What is DTE Gas's Customer Attachment Program, and what level of investment does the Company propose?

A. DTE Gas's Customer Attachment Program ("CAP") provides a method for expanding the gas distribution system to serve new customers. In this proceeding, the Company proposes $262.0 million in capital expenditures for New Market Attachments from January 1, 2025, through September 30, 2027.[75] New Market Attachments represent the Company's multi-customer community expansion efforts that seek to add a cohort of customers over several years through the addition of new infrastructure. This represents an average of $95.7 million per year, approximately $12 million per year higher than the 2024 historical spend of $83.7 million.[76] Two New Market Attachment projects meet the threshold to be included in Schedule B5.5 DTE Highest Cost Top 25 Capital Projects: Austin Area Expansion Project and the US-2 project. The Company attributes this increase primarily to "increased demand by homeowners for conversion from the higher cost of propane to natural gas, particularly in the community expansion space."[77] DTE is actively targeting propane-to-gas conversions, with $324,000 budgeted annually for proactive gas expansion marketing.[78]

Q. How does the CAP model determine costs borne by new customers versus existing ratepayers?

A. Each CAP project uses a discounted Net Present Value ("NPV") analysis of the revenue deficiency anticipated over a 20-year payback period. If projected revenues from the new customers are insufficient to cover the cost of the expansion, the new customer pays a Contribution in Aid of Construction ("CIAC") – typically collected as a Fixed Monthly Surcharge over five years. The remainder of the construction cost – the "allowance" – is

[75] Huffman, Direct Testimony, p. 38.
[76] *Id.* at 39.
[77] *Id.*
[78] Exhibit AA-56; Exhibit AA-57.

capitalized by DTE Gas and enters the rate base, where it is recovered from all ratepayers through distribution rates. The utility's investors earn a rate of return on this capitalized allowance.[79]

Q. How is the CAP model designed to protect existing customers?

A. The fundamental regulatory principle underlying the design of the CAP is that existing customers should not subsidize new customers. As the MPSC website states, a CAP's purpose is "to provide gas utilities with a method of expanding their systems to new customers without such expansions being subsidized by existing customers."[80] Whether this principle is being upheld depends entirely on whether the model's revenue projections and the assumptions underlying them are reasonable.

Q. Does the current approach to determining CIACs and allowances sufficiently protect existing customers?

A. No. The remainder of this section will show that existing customers are currently financing a significant portion of new construction costs and emphasize that they bear the burden of increasing risk associated with under recovery of CIACs.

VIII-B. Analysis of DTE's CAP Project Models

Q. Did you examine DTE's individual CAP project models?

A. Yes. DTE provided 74 CAP model workbooks covering Area Expansion Projects from 2024 through 2026.[81] These workbooks used two distinct spreadsheet templates. I examined the design of these model templates in detail. I also extracted and analyzed the

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[79] Huffman, Direct Testimony, p. 40-45. *See also*, DTE Gas Rate Book, Sections C8.2 and C8.6.

[80] Michigan Public Service Commission, Customer Attachment Program; *see also*, Huffman, Direct Testimony, p. 44-45.

[81] Exhibit AA-58.

construction costs, customer targets, consumption assumptions, financial parameters, and 20-year revenue projections embedded in every workbook.

Q. What are the aggregate results across all 74 projects?

A. The 74 projects target a combined 13,340 new customers at a total construction cost of $104.4 million. Of this total, new customers pay $32.8 million in CIACs (31.4%), while existing ratepayers finance $71.6 million in allowances that enter rate base (68.6%). Table 4 summarizes these results:

Table 4. *New Market Attachments*

	2024	2025	2026	Total
Number of projects	28	18	28	**74**
Target customers	3,949	3,140	6,251	**13,340**
Total construction cost	$29.8M	$24.1M	$50.5M	**$104.4M**
CIAC (customer pays)	$9.1M	$8.1M	$15.6M	$32.8M
Allowance (ratepayer-funded)	$20.7M	$16.0M	$34.9M	**$71.6M**
Allowance as % of total	69.6%	66.3%	69.2%	**68.6%**
Avg. cost per customer	$7,535	$7,680	$8,081	$7,828
Avg. allowance per customer	$5,242	$5,093	$5,588	**$5,370**

On average, existing ratepayers finance $5,370 per new customer—more than double the $2,458 CIAC paid by the new customer. Per-customer costs are also rising: from $7,535 in 2024 to $8,081 in 2026, an increase of 7.2%.

Q. Did you obtain system-wide data on DTE Gas's new customer connection costs to corroborate your analysis of the 74 CAP project models?

A. Yes. In response to Ann Arbor's Fourth Discovery Request, DTE Gas provided five years of aggregate data on new *service* installations, including gross costs, CIACs collected, and net amounts added to rate base. This data apparently captures the costs incurred with individual service connections. These system-wide figures independently confirm that existing ratepayers finance the vast majority of the costs of connecting new customers. Table 5 below summarizes DTE Gas's system-wide new service installation data for 2021 through 2025.

Table 5. *DTE Gas System-Wide New Service Installation Costs, 2021–2025*[82]

Year	Gross New Service Cost	CIAC Collected	Net Cost to Rate Base	Attachments	Ratepayer Subsidy Rate
2021	$36.3 M	$1.7 M	$34.6 M	10,219	95.3%
2022	$41.2 M	$1.7 M	$39.5 M	10,358	95.9%
2023	$38.5 M	$1.9 M	$36.6 M	9,990	95.1%
2024	$39.5 M	$1.6 M	$37.9 M	11,068	95.9%
2025	$39.1 M	$4.0 M	$35.1 M	9,446	89.8%
Total	**$194.6 M**	**$10.9 M**	**$183.7 M**	**51,081**	**94.4%**

Over the five-year period, DTE Gas spent $194.6 million on new service installations and collected only $10.9 million in CIACs—a system-wide CIAC recovery rate of just 5.6%. The remaining $183.7 million was added to rate base, where it earns a guaranteed return for DTE's investors and is recovered from all existing ratepayers.

Q. What proportion of DTE's new customer connections receive a line extension allowance covering 100% of the connection cost—meaning the new customer pays zero CIAC?

A. Approximately half. DTE Gas provided data for 2024 and 2025 showing the number of connections that required zero CIAC versus those that required some customer contribution (Table 6).

[82] Exhibit AA-59

Table 6. *Zero-CIAC vs. CIAC-Required Connections, 2024–2025*[83]

Year	Zero-CIAC Connections	CIAC-Required Connections	Total Connections	% Zero-CIAC
2024	5,403	5,665	11,068	48.8%
2025	4,817	4,627	9,444	51.0%

Q. What is the significance of these zero-CIAC connections for the risk analysis you presented earlier?

A. For approximately 5,000 customers per year, the entire capital cost of connection enters rate base with no upfront contribution from the customer who caused the cost. These customers have no financial commitment to the gas system beyond their monthly bill. If they reduce consumption existing ratepayers have no recourse to recover the stranded investment.

<u>VIII-C. DTE's CAP Model Fails to Account for Increasing Risk to Gas Consumption</u>

Q. What consumption assumption does the CAP model use?

A. Each of the 74 CAP models assumes that each new customer will consume gas at a constant rate over the full 20-year evaluation period. The average assumed consumption for residential customers is 121 Mcf per year. This figure is assumed to be static over 20 years. There is no efficiency improvement, no fuel-switching, and no attrition modeled in any project.

Q. Is 121 Mcf per year a reasonable starting assumption?

A. It is above average but may be defensible as a starting point for the specific population being served. The Michigan statewide average residential natural gas consumption was

[83] *Id.*

approximately 80 Mcf per customer in 2024, according to EIA data.[84] CAP customers tend to be in rural areas with older homes currently heated with propane, so above-average starting consumption may be plausible. However, given that 121 Mcf is 52% above the statewide average, continuing with the assumption that usage will remain constant for two decades is unreasonable, especially in light of trends in building energy use declining due to efficiency improvements made at various time points in an ownership cycle.

Q. Does DTE's own testimony support the assumption of constant consumption over 20 years?

A. No. DTE's own Gas Delivery Plan directly contradicts the constant-consumption assumption used in every CAP model. On page 85 of the Gas Delivery Plan, DTE states: "DTE Gas saw an 18% reduction in weather-normalized demand per customer in 2024 compared to 2005."[85] The GDP further states: "DTE Gas expects to continue to achieve 1% energy efficiency savings annually."[86]

The Company's planning witness projects ongoing 1% annual demand decline, while its investment models assume zero decline for 20 years. If the Gas Delivery Plan's assumptions are sound, then every CAP model systematically overstates the revenue these new customers will generate, and the allowances funded by existing ratepayers are correspondingly understated.

[84] Exhibits AA-60 and AA-61 (273,737 million cubic feet delivered to 3,441,467 residential consumers in Michigan).
[85] Exhibit A-12, Schedule B5.6, p. 85.
[86] *Id.*

Q. What is the impact of applying DTE's own 1% annual demand decline to the CAP models?

A. The impact is material. At 1% annual decline, a customer cohort starting at 121 Mcf per year consumes 109 Mcf in Year 10 and 99 Mcf in Year 20. This represents a $275 potential 20-year NPV under recovery. Because the CAP model calculates the allowance based on the assumption that revenue remains constant, any decline in actual consumption means the revenue will fall short of projections, and the allowance will not be fully "earned back" by the new customers. The shortfall is borne by existing ratepayers. Rising rates may offset this, but it illustrates that the CIAC calculation used to protect existing ratepayers rests on assumptions that are at risk of change.

VIII-D. The Allowance Structure Creates Asymmetric Risk

Q. Who bears the risk if the CAP model's consumption assumptions prove optimistic?

A. Existing ratepayers bear the entire downside risk. The allowance enters the rate base and earns a guaranteed return for DTE's investors regardless of whether the new customers actually consume gas at the projected levels.[87] If a new customer reduces consumption, installs a heat pump, or leaves the system entirely, the infrastructure investment is already in rate base and continues to be recovered from all remaining customers. The new customer, meanwhile, has no obligation beyond the surcharge period (typically 5 years) and no penalty for reducing consumption. DTE's investors earn their authorized return regardless. The only party exposed to the risk of optimistic assumptions is the existing ratepayer.

[87] Exhibit AA-62.

Q. Does DTE perform any sensitivity analysis on these assumptions?

A. No. In response to discovery, DTE confirmed that it "does not perform formal sensitivity analysis on customer attachment projections."[88] The Company has not modeled any scenario in which demand declines, customers attrit, or fuel-switching occurs—despite its own Gas Delivery Plan projecting exactly these outcomes. No CAP model includes any alternative scenario. Every one of the 74 models presents a single, maximally optimistic forecast as the basis for committing $71.6 million of existing ratepayer capital.

<u>VIII-E. The Emerging Heat Pump Threat to CAP Revenue Projections</u>

Q. You mentioned fuel-switching as a risk. Can you describe a specific scenario?

A. Yes. The most significant near-term risk to CAP revenue projections is the hybrid heat pump scenario. A customer who connects to natural gas through a CAP project but subsequently undertakes energy efficiency measures or installs a cold-climate heat pump as a supplemental heating system could reduce their gas consumption from the modeled 121 Mcf per year significantly, depending on design. This is not hypothetical. DTE's own Guidehouse analysis, evaluates this exact hybrid heating configuration and acknowledges it as a viable and growing option.[89]

Q. Should ratepayers bear this risk?

A. No. Long-term revenue forecasts are increasingly uncertain. Over a 20-year horizon, a model that ignores efficiency improvements, DTE's own 1% annual demand decline projection, customer fuel-switching, and the emergence of competitive heat pump technology is not a model that prudently protects existing ratepayers. If gas service is

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[88] I*d.*
[89] Exhibit A-29, Schedule 1. *See also*, Decker, Direct Testimony, p. 4-5; 13-14.

genuinely the best option for new customers, they should be willing to bear a larger share of the connection cost. The current structure allows new customers to capture the full benefit of low gas prices while shifting most of the infrastructure risk to existing ratepayers who had no part in the decision to extend service.

VIII-F. DTE's Posture on Decarbonization Risk Is Internally Contradictory

Q. How does DTE characterize the risk that decarbonization policies pose to CAP investments?

A. DTE's position is inconsistent. In direct testimony, the Company stated that it is "not currently aware of any proposed legislation or regulation that would materially impact its current business" while acknowledging "that State or Federal legislative and regulatory developments could impact natural gas demand and DTE Gas's capital plans."[90] The Company further acknowledges that "as GHG emission reductions get more aggressive to reach Michigan's 2050 net zero goal, there is likely to be further reduction in natural gas demand."[91] The Company also acknowledged municipal climate commitments, including the City of Ann Arbor's A^{2}ZERO Carbon Neutrality Plan.[92] When asked to quantify the financial risks to its gas distribution investments from state and local decarbonization policies, DTE objected to the question entirely.[93]

This posture is untenable. DTE simultaneously filed a Gas Delivery Plan that acknowledges ongoing demand decline and emerging decarbonization risk, while asking the Commission to approve $262 million in expansion investments premised on a model

[90] Decker, Direct Testimony, p. 17.
[91] Exhibit A-12, Schedule B5.6), p. 85.
[92] Exhibit AA-19
[93] Exhibit AA-63.

that assumes neither and puts existing ratepayers at risk of paying for stranded assets at worst and under-recovering the already-insufficient CIAC due to lower than projected gas usage at best.

VIII-G. Regulatory Actions in Other Jurisdictions

Q. Have other states reformed or eliminated gas line extension allowances?

A. Yes, as shown in Table 7 below.

Table 7. *Status of line extension allowances in selected states.*

State	Action	Year	Key Features
California	Eliminated LEAs	2022	CPUC order; exceptions require a petition demonstrating no feasible alternative to gas service
Colorado	Eliminated LEAs	2023	Legislation (SB 23-291); immediate implementation for new gas connections
Washington	Reduced LEAs	2021	Shortened payback period to 7 years; reduced allowance amounts
Oregon	Reduced LEAs	2022	Set maximum fixed allowance by customer class; reduced from historical levels
New York	Eliminated the 100-foot rule.	2025	Allowances eliminated via Legislation (S.8417/A.8888)
Massachusetts	Under consideration	Pending	DPU has drafted a straw proposal for the elimination of line extension allowances.
Maryland	Eliminated LEAs	2025	Commission order (No. 91683)

Across the country, regulators and legislators in at least seven states have taken action to reduce or eliminate gas line extension allowances, recognizing that these subsidies expose existing ratepayers to unacceptable risks and are inconsistent with climate policy objectives.[94]

California. In September 2022, the California Public Utilities Commission issued a

[94] RMI, Cutting These Subsidies Could Save States Millions of Dollars, by Mike Henchen and Joe Dammel (August 27, 2025) (Provided at Exhibit AA-64).

decision phasing out gas line extension allowances for all gas utilities across the state.[95] The CPUC found that continued subsidization of gas system expansion was inconsistent with the state's climate goals and posed stranded asset risks for ratepayers.

Colorado. In 2023, the Colorado legislature directed the state's Public Utilities Commission to eliminate line extension allowances, recognizing the growing risk that gas infrastructure investments would not be recovered from new customers as the state pursues its emissions reduction targets.[96]

New York. On December 19, 2025, Governor Hochul signed legislation repealing New York's statutory "100-foot rule," which had required utilities to provide free gas connections to any customer within 100 feet of an existing gas main.[97] The repeal is estimated to save New York ratepayers approximately $600 million annually.

Maryland. In June 2025, the Maryland Public Service Commission issued Order No. 91683, directing that new gas customers pay the full connection cost upfront.[98] The Maryland Office of People's Counsel estimated that eliminating line extension allowances will save BGE and Washington Gas customers approximately $1 billion through 2035. The Maryland PSC noted that "current natural gas policies may no longer be compatible with the state's greenhouse gas emissions reduction targets" and that existing policies "expose all ratepayers to the risk of stranded gas infrastructure costs."

Massachusetts. The Massachusetts Department of Public Utilities has been conducting a multi-year investigation into line extension policies through its D.P.U. 20-80 proceeding.

[95] California Public Utilities Commission, Decision 22-09-026 (September 2022).
[96] Colorado SB 23-291 (2023).
[97] New York S.8417/A.8888 (2025).
[98] Maryland Public Service Commission, Order No. 91683 (June 13, 2025).

In August 2025, the Department issued a Revised Straw Proposal for the elimination of line extension allowances, with limited exceptions for commercial and industrial loads where no technically feasible electric alternative exists.[99]

<u>VIII-H. Options & Recommendations</u>

Q. What policy options are available to the Commission to reform line extension allowances?

A. Several options exist along a spectrum from incremental reform to the full elimination of allowances:

First, the Commission could prohibit line extension allowances entirely, requiring new customers to pay the full cost of connection. This is the approach adopted or being implemented in California, Colorado, New York, and Maryland. Under this approach, new customers would still be able to connect to the gas system, but the cost of the connection would be borne by the new customer rather than socialized across all ratepayers.

Second, the Commission could shorten the payback period used to calculate the allowance. DTE Gas currently uses a twenty-year payback period, which assumes that new customers will use gas at projected levels for two decades. Shortening this period to seven years, as adopted in Washington, would result in smaller allowances and correspondingly larger customer contributions, better reflecting the increasing uncertainty of long-term gas revenues.

Third, the Commission could establish a minimum CIAC, ensuring that every new

[99] Massachusetts Department of Public Utilities, Interlocutory Order D.P.U. 20-80-E (August 8, 2025).

customer pays at least a specified portion of the actual connection cost regardless of projected revenues. This would provide a floor of cost recovery for each connection and reduce the risk of unrecovered allowances.

Fourth, the Commission could require new customers to guarantee revenues supporting their allowance calculation, for example through a clawback provision. Under this approach, if a customer substantially reduces gas consumption or disconnects from the gas system within a specified period, the customer would be responsible for repaying the unamortized portion of the allowance.

Q. What approach do you recommend?

A. I recommend that the Commission take decisive action to protect existing ratepayers from the growing risks of line extension allowances. Specifically, I recommend the following:

Primary Recommendation: The Commission should eliminate line extension allowances for residential new construction. New residential customers should be required to pay the full cost of connecting to the gas distribution system. This approach is consistent with the actions taken in many other states, and reflects the fundamental ratemaking principle that costs should be borne by the customers who cause them. Eliminating residential allowances does not prohibit new gas connections; it simply requires new customers to assume the risks associated with the actual cost of the connection rather than socializing those risks across all existing ratepayers.

Commercial and Industrial Exception: The Commission should provide a limited exception for specific commercial and industrial loads where gas service is required for process heating or other applications for which no technically feasible electric alternative exists. Any allowance granted under this exception should be calculated using a shortened payback period of no more than ten years and should include a clawback provision requiring repayment if the customer substantially reduces gas consumption or disconnects within ten years of connection.

Alternative Recommendation: If the Commission determines that a full elimination of residential allowances is premature at this time, it should, at a minimum, (a) shorten the CAP model's payback period from twenty years to ten years; (b) establish a minimum CIAC for all new connections, ensuring that new customers pay at least 75% of the actual connection cost; and (c) require the Company to file an annual report on the performance of the CAP, including actual versus projected revenues from new customer cohorts, to enable the Commission to assess whether existing customers are being subsidized.

As the National Regulatory Research Institute observed in its comprehensive evaluation of line extension practices, allowances may be "bad policy" when, "in the absence of large-scale public benefits or utility internal efficiencies, subsidies funded by a utility's existing customers come across as both unfair and economically inefficient."[100] The growing risks to existing ratepayers, the actions taken in peer jurisdictions, and Michigan's own climate objectives all point toward the need for reform.

Every year that allowances continue without reform, DTE Gas ratepayers finance tens of millions of dollars in new connections with no assurance that the projected benefits will materialize. The Commission has both the authority and the obligation to protect ratepayers from this growing risk. At a minimum, it should investigate how such connection programs operate and differ among utilities.

[100] Line Extensions for Natural Gas: Regulatory Considerations, National Regulatory Research Institute (February 2013) (Relevant excerpt at Exhibit AA-65)

IX. HOW OTHER STATES ARE ADDRESSING THE FUTURE OF GAS ISSUES

Q. Why is a review of other states' approaches relevant to this proceeding, if Michigan does not have legislation requiring a transition away from gas?

A. The challenges identified throughout this testimony are systemic challenges facing gas utilities nationwide, as market trends show. Multiple state commissions, including those in politically and geographically diverse jurisdictions, have independently concluded that existing regulatory frameworks threaten to create a severe financial burden on future ratepayers. In the absence of an MPSC investigation or other state-initiated review of the future of gas, such a review is important for highlighting future risks that DTE faces relevant to the investments proposed in this proceeding.

Q. Which states have launched dedicated Future of Gas proceedings, and what have they accomplished?

A. Since 2020, at least 14 proceedings addressing the future of the gas system have been opened across 13 states and the District of Columbia. The National Association of Regulatory Utility Commissioners recognized the need for comprehensive gas utility planning as a priority issue in 2023, establishing a Task Force on Natural Gas Resource Planning with 21 member states. The Task Force's May 2025 report reviews gas utility planning requirements across nine states and provides a resource library for commissions considering action.

Notably, while electric utility integrated resource planning has been standard practice since the 1980s, with over 40 states requiring electric IRPs, gas utility planning requirements are far newer and less widespread. Most of the states reviewed by NARUC adopted gas planning requirements within the last five years.

While each state has taken a different approach reflecting its own policy context, common elements include: multi-scenario demand-forecasting requirements; evaluation of non-pipeline alternatives; stranded asset and depreciation review; and equity protections for vulnerable customers. I summarize the approach and key insights from five leading states in this section of testimony: Massachusetts, New York, California, Colorado, and Illinois. A detailed state-by-state comparison is provided in Exhibit AA-30.

Massachusetts. The Massachusetts Department of Public Utilities opened its "Future of Gas" investigation (D.P.U. 20-80) in October 2020. After a multi-year process that included an independent consultant study analyzing eight decarbonization pathways, extensive stakeholder engagement, and technical sessions, the DPU issued its landmark Order 20-80-B in December 2023. The order declared the Commonwealth's future "beyond gas" and established a comprehensive new regulatory framework. Key elements include a requirement that gas utilities demonstrate non-pipeline alternatives were adequately considered before recovering costs for new infrastructure; five-year Climate Compliance Plans with performance metrics; a prohibition on cost recovery for gas marketing and promotion; an order directing all gas utilities to study the potential magnitude of stranded investments and the impacts of accelerated depreciation; and a requirement for integrated gas-electric planning. Massachusetts is particularly relevant to Michigan's gas system challenges: the state has among the nation's highest concentrations of leak-prone pipe and has created a framework that requires evaluating alternatives before defaulting to pipeline replacement, a dynamic directly pertinent to DTE's Gas Renewal Program.

New York. The New York Public Service Commission opened its gas planning proceeding (Case 20-G-0131) in March 2020, triggered by a crisis in which National Grid imposed a moratorium on new gas connections in downstate New York, exposing the inadequacy of existing gas planning. The PSC's May 2022 order requires all gas utilities to file comprehensive Long-Term Plans with a 20-year planning horizon. Three scenarios are mandatory: business-as-usual, a low-carbon transition scenario, and a no-infrastructure scenario. Plans must include demand forecasts, supply analysis, NPA evaluation, and capital investment justification tied to each scenario. Annual compliance reports are required, and an Avoided Cost of Gas Working Group was established to evaluate depreciation and stranded asset approaches.

California. California's approach began with a foundational analytical study, the E3 California "Retail Gas Study" published in 2020 for the California Energy Commission, which established that building electrification is the lower-cost, lower-risk decarbonization pathway compared to renewable natural gas or hydrogen for buildings.[101] The state has since produced the most concrete operational results of any jurisdiction. The CPUC eliminated gas line extension allowances effective July 2023. In 2024, the legislature enacted SB 1221, authorizing up to 30 neighborhood-scale targeted electrification pilot projects.

Colorado. Colorado's PUC gathered information and engaged stakeholders on gas transition issues through a pre-rulemaking investigatory docket even before legislation established binding GHG reduction targets to be implemented through Gas Infrastructure

[101] The Challenge of Retail Gas in California's Low-Carbon Future, California Energy Commission, (April 15, 2020) (Executive Summary at Exhibit AA-66).

Plans. Colorado demonstrates the value of non-adjudicated investigatory proceedings to lay the groundwork for robust decision-making, and the state's gas system characteristics and emphasis on city-oriented pilot programs are directly relevant to Michigan's context.

Illinois. The Illinois Commerce Commission opened its Future of Gas proceeding (Docket 24-0158) after simultaneous rate cases from all three major gas utilities revealed systemic problems in 2023. The Peoples Gas System Modernization Program was launched in 2011 as a comprehensive pipe replacement program with an initial cost estimate of $1.4 billion, the program escalated dramatically. An independent analysis found completing the program would cost $12.8 billion.[102] The ICC found that Peoples Gas had not prioritized removal of the highest-risk pipes and that cast iron and ductile iron retirement rates actually slowed over time despite massive spending increases. The customer impact has been large: a record $303 million rate hike in November 2023, with nearly one in five customers more than 30 days delinquent on their bills and $74.5 million in total customer debt. In February 2025, the ICC rejected Peoples Gas's $7.2 billion proposal and ordered an accelerated but risk-focused approach targeting only the highest-risk pipe. The parallels between the Peoples Gas System Modernization Program and DTE's Gas Renewal Program, which accounts for approximately 40 percent of DTE's 10-year capital plan, warrant consideration by this Commission.

Q. What are the key lessons from these proceedings?

A. Three categories of lessons emerge: what has worked, what has not, and what Michigan can improve upon.

[102] Peoples Gas: Escalating Business Risk in a Changing Energy Landscape, prepared by Citizens Utility Board of Illinois and Groundwork Data (October 2024) (Executive Summary at Exhibit AA-67).

What has worked. States that have acted decisively on discrete, well-defined issues have produced measurable results. California's elimination of line extension allowances, effective July 2023, immediately changed the economics of gas system expansion.[103] Colorado's rejection of hydrogen, certified gas, and carbon offsets as Clean Heat Plan compliance tools—based on rigorous cost-effectiveness analysis—prevented ratepayer resources from being directed toward strategies that would not achieve meaningful emissions reductions.[104] Consolidated Edison's Energy Exchange Program in New York, which offers $10,000–$20,000 per customer for electrification of customers served by aging service connections, has demonstrated that non-pipeline alternatives can be implemented at the individual customer level without requiring resolution of system-wide planning questions.[105]

What has not worked. Several states have experienced significant delays, analytical detours, and procedural bottlenecks that Michigan should learn from. Massachusetts opened its Future of Gas investigation in October 2020 and did not issue its framework order until December 2023 – over three years later – during which time gas utilities continued to invest billions in system expansion without the guardrails the proceeding was designed to establish. A central source of delay in multiple jurisdictions has been extended debate over the role of renewable natural gas and hydrogen in building decarbonization. These debates consumed substantial regulatory resources despite the fact that, as I have demonstrated in Section VI of this testimony, RNG is fundamentally supply-constrained and hydrogen is thermodynamically inferior to direct electrification

[103] California Public Utilities Commission, Decision 22-09-026 (September 2022).
[104] Colorado PUC, Decision No. C24-0485, Proceeding No. 23AL-0267G (June 2024).
[105] *See*, ConEdison, Energy Exchange Program.

for building heating. Oregon provides a further cautionary example: the state opened a natural gas fact-finding investigation in 2021 but closed it in January 2023 without issuing a binding order, illustrating the risk that investigatory proceedings without clear regulatory direction may not produce actionable results.[106] Finally, any forecasting should not be performed only by a utility, but should be conducted within parameters *approved* by MPSC.

Delay incurs costs. Illinois provides the most directly relevant lesson for Michigan. The Peoples Gas System Modernization Program was originally estimated at $1.4 billion in 2007 and launched in 2011.[107] By the time the program formally received legislative authorization through a ten-year rider in 2013, the estimate had grown to $2.6 billion.[108] The rider enabled automatic pass-through of costs to customers without the scrutiny of individual rate case review. By the time independent analysis was conducted in 2024, the projected completion cost had reached $12.8 billion.[109] The ICC found that Peoples Gas had not prioritized removal of the highest-risk pipes, that cast iron and ductile iron retirement rates actually slowed over time despite massive spending increases, and that the company had not complied with multiple investigation orders. The critical failure was not the decision to replace pipe – it was the absence of rigorous, independent oversight during the years when the program was building inertia. By the time the ICC intervened

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[106] Oregon PUC, Order No. 23-005, Docket UM 2178 (January 2023).

[107] Exhibit AA-68 (Stephanie Zimmermann, "Peoples Gas Pipe Replacement Is Costing Chicagoans More," Chicago Sun-Times (Feb. 16, 2021).

[108] Exhibit AA-69 (Robert Channick, "Peoples Gas Pipeline Program Will Cost Another $12.8 Billion to Complete," Chicago Tribune (Oct. 29, 2024).

[109] Peoples Gas: Escalating Business Risk in a Changing Energy Landscape, prepared by Citizens Utility Board of Illinois and Groundwork Data (October 2024) (Executive Summary at Exhibit AA-67).

in February 2025, the program had consumed $3.3 billion in ratepayer funds and generated political and contractual momentum that made course correction far more difficult and costly than early intervention would have been.

DTE's Gas Renewal Program exhibits early warning signs of a similar trajectory: escalating per-mile costs, absence of independent risk assessment, reliance on renegotiated rather than competitively rebid contracts, and no engineering studies in the past five years assessing whether underlying safety risks have increased or decreased. The GRP accounts for approximately 40 percent of DTE's ten-year capital plan. The Commission should not wait until these dynamics are entrenched to establish the oversight frameworks that Illinois lacked.

Q. What is your primary recommendation for action beyond this rate case?

A. The Commission should initiate a comprehensive Future of Gas proceeding and establish defined deliverables within twelve months of opening the docket. The issues identified throughout this testimony – declining gas demand, rising infrastructure costs, stranded-asset risk, the absence of evaluation of non-pipeline alternatives, the lack of integrated gas-electric planning, and the need for customer equity protections – cannot be adequately resolved within a single rate case. But neither should they be consigned to an open-ended investigation. The lesson of other states is that proceedings without clear deliverables and timelines produce delay, not results.

Q. What specific deliverables should the proceeding produce?

A. I recommend five defined workstreams, each with a deliverable within twelve months.

First: End line extension allowances. If the Commission does not act on this issue in the present rate case, it should be the first order of business in a Future of Gas proceeding. As detailed in Section VIII and as demonstrated by the actions of at least six peer states, the evidence supporting reform is conclusive. The deliverable should be a Commission order eliminating or substantially reforming line extension allowances for residential new construction, with a limited commercial and industrial exception subject to shortened payback periods and clawback provisions.

Second: Provide guidance to investments that are likely to be approved as part of an electrification plan. Under Michigan law, utilities may recover expenses related to an efficient electrification plan, but without a clear precedent regarding the types of programs that may be approved, utilities may be reluctant to commit the effort to develop such a plan. The Commission should provide guidance on the likelihood of approval for certain types of programs or efforts. For instance, the Commission could evaluate programs modeled on Consolidated Edison's Energy Exchange approach, offering electrification incentives to customers served by leak-prone infrastructure for which the cost of conversion is competitive with that of pipe replacement. The deliverable should be a clear statement from the Michigan Commission about the type of program proposal likely to be approved: one with identified target segments, incentive structures, and cost-recovery mechanisms.

Third: Open an investigation into coordinated non-pipeline alternatives. The Commission should initiate a focused investigation into how non-pipeline alternatives can be systematically identified, evaluated, and implemented across the gas system—not on a project-by-project basis, but as a component of long-term infrastructure planning. The Commission should use this proceeding to describe the kind of projects that are unlikely to be deemed prudent or reasonable unless accompanied by an analysis showing

NPAs are not cost-effective compared to the traditional pipeline investment, based on system condition data and planned replacement maps that enable the Commission, intervenors, and the public to identify places where NPAs can provide cost savings. Finally, the Commission can set forth a framework for pilot programs at the neighborhood and pipe-segment levels that is likely to be approved.

Fourth: Open a financial pathways investigation. The Commission should initiate a focused investigation into the financial and rate impacts of different gas system transition pathways. This is where a pathways analysis adds genuine value—understanding the financial consequences for ratepayers of different system configurations and management strategies. The investigation should model the rate and bill impacts of hybrid heating scenarios (in which customers retain gas backup but use heat pumps for most heating), managed electrification scenarios (in which targeted segments are transitioned off the gas system), and various capital expenditure trajectories. Critically, it should also evaluate financial management tools: rate design approaches that maintain affordability as per-customer consumption declines; securitization mechanisms that could reduce the cost of retiring undepreciated gas assets; accelerated depreciation schedules that reduce stranded asset risk; and transition financing strategies that spread costs equitably across time and across customer classes. The deliverable should be an independent analysis—scoped to answer these specific questions under Michigan-specific conditions—and a Commission order establishing the planning framework and financial tools that will govern gas utility capital decisions going forward.

Q. Why is it important that the Commission act now and incorporate consideration of these risk factors in a Future of Gas proceeding or in individual gas rate case and depreciation proceedings?

A. Every year that a major infrastructure program operates without rigorous oversight, independent assessment, and alternatives analysis, it builds financial and contractual constraints and risks that make course correction more difficult and more expensive. DTE's Gas Delivery Plan outlines approximately $9.6 billion in capital investment over the next ten years. The Gas Renewal Program alone accounts for roughly 40 percent of that plan. These expenditures are proceeding without NPA evaluation, without demand decline modeling, and without integrated gas-electric planning. The Commission has both the authority and the obligation to establish the planning frameworks, oversight mechanisms, and transition strategies that will determine whether Michigan's gas system transition is managed proactively—at lower cost and with greater equity—or reactively, after the costs have already been incurred. It will also offer key risk metrics to utilities when they weigh investments they will undertake.

Michigan's position among states with climate goals but without a proceeding to attempt to consider the impacts of following those goals for the gas system is increasingly anomalous. Moreover, even if the state of Michigan renounced its climate goals, individual customer choices are already reducing usage and that trend is likely to continue. The Commission has the opportunity to design a proceeding that is more strategic, more focused, and more protective of ratepayers than any other state has taken to date. It should do so.

X. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes.

Q. Do you swear under penalty of perjury that the statements above are true to the best of your knowledge, information, and belief?

A. Yes.

Michael J Walsh

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Michael Walsh