CITY OF ANN ARBOR, MICHIGAN

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March 13, 2026

VIA ELECTRONIC CASE FILING

Ms. Lisa Felice, Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48917

RE: MPSC Case No. U-21973

Dear Ms. Felice,

Attached please find the **Exhibits of Rick Brown, Dr. Melissa Stults, and Michael Walsh on behalf of the City of Ann Arbor** for the above-referenced case, along with proof of service.

Please contact me if you have any questions.

Sincerely,

Valerie Jackson
Assistant City Attorney,
City of Ann Arbor

City of Ann Arbor
Exhibit List
Case No. U-21973

Exhibit	Title	Witness
AA-1	Resume of Rick Brown	Rick Brown
AA-2	Discovery Response AADG-3.10ei	Rick Brown
AA-3	Discovery Response AADG-3.8c	Rick Brown
AA-4	Discovery Response AADG-3.11a	Rick Brown
AA-5	Discovery Response AADG-3.9a	Rick Brown
AA-6	Discovery Response AADG-3.6g	Rick Brown
AA-7	Discovery Response AADG-3.6h	Rick Brown
AA-8	Discovery Response AADG-3.9b	Rick Brown
AA-9	Discovery Response AADG-3.7b	Rick Brown
AA-10	Discovery Response AADG-3.7aiv	Rick Brown
AA-11	Discovery Response AADG-3.7aiii	Rick Brown
AA-12	Discovery Response AADG-3.8ei-evi	Rick Brown
AA-13	Discovery Response AADG-2.3a	Rick Brown
AA-14	Discovery Response AADG-2.3b	Rick Brown
AA-15	Discovery Response AADG-5.1d	Rick Brown
AA-16	Discovery Response AADG-2.1h	Rick Brown
AA-17	Discovery Response AGDG-3.113	Rick Brown
AA-18	Resume of Dr. Melissa Stults	Dr. Melissa Stults
AA-19	Discovery Response AADG-2.9gi-v	Dr. Melissa Stults
AA-20	Ann Arbor City Council Resolution # R-23-101	Dr. Melissa Stults
AA-21	*Natural Gas Use Per Residential Customer*, AGA Energy Insights, Nov. 2024, Vol. 2024-10	Dr. Melissa Stults
AA-22	*Tracking the Heat Pump & Water Heater Market in the United States*, RMI, available at https://rmi.org/insight/tracking-the-heat-pump-water-heater-market-in-the-united-states/	Dr. Melissa Stults
AA-23	Attachment to Discovery Response AADG1.1	Dr. Melissa Stults
AA-24	Cornelius, P., Van de Putte, A. & Romani, M. (2005). Three Decades of Scenario Planning in Shell. *California Management Review, 48(1),* 92-109.	Dr. Melissa Stults
AA-25	Discovery Response AADG-2.9a	Dr. Melissa Stults
AA-26	Direct Testimony of Dr. Bente Villadsen from Case No. U-21291 (Excerpt)	Dr. Melissa Stults
AA-27	Discovery Response MECCUBDG-8.1a	Dr. Melissa Stults
AA-28	Takemura, A., *Heat pump sales dipped in 2025. They still beat gas furnaces*, Canary Media (Feb. 13, 2026)	Dr. Melissa Stults
AA-29	Resume of Michael Walsh	Dr. Michael Walsh
AA-30	State Future of Gas Proceeding Matrix	Dr. Michael Walsh
AA-31	DTE Gas Revenue Requirement Model	Dr. Michael Walsh
AA-32	Discovery Response MECCUBDG-5.2b	Dr. Michael Walsh

AA-33	Discovery Response STDG-2.13	Dr. Michael Walsh
AA-34	Discovery Response AGDG-6.221	Dr. Michael Walsh
AA-35	Discovery Response MECCUBDG-5.12a-b	Dr. Michael Walsh
AA-36	EGLE Report: *Clean, Safe, and Affordable* (Excerpts)	Dr. Michael Walsh
AA-37	Michigan Population Projections Through 2050 (Excerpt)	Dr. Michael Walsh
AA-38	Michigan Population Growth Domestic Gains (Excerpt)	Dr. Michael Walsh
AA-39	Discovery Response MECCUBDG-3.16g	Dr. Michael Walsh
AA-40	DHInfrastructure & CUB, *Potential Bill Impacts of Business-as-Usual in Michigan* (Excerpt)	Dr. Michael Walsh
AA-41	ICF, Michigan Renewable Natural Gas Study (Excerpt)	Dr. Michael Walsh
AA-42	Discovery Response AADG-1.6	Dr. Michael Walsh
AA-43	MPSC Form P-522, p. 305B and 306C	Dr. Michael Walsh
AA-44	Olaguer, E.P. et al., *The Michigan-Ontario Ozone Source Experiment (MOOSE): An Overview*	Dr. Michael Walsh
AA-45	Sargent, M.R. et al., "Majority of US urban natural gas emissions unaccounted for in inventories"	Dr. Michael Walsh
AA-46	Direct Testimony of Robert Ackley from Case No. U-21291 (Excerpt)	Dr. Michael Walsh
AA-47	American Gas Foundation, *Renewable Natural Gas Supply Assessment* (Excerpt)	Dr. Michael Walsh
AA-48	EPRI, *Net-Zero Scenarios 2.0* (Excerpt)	Dr. Michael Walsh
AA-49	Cole Rosengren, "How the EPA's Renewable Fuel Standard program changes could be boon for landfill and AD operators," *Waste Dive*	Dr. Michael Walsh
AA-50	Jacob Wallace, "Biogas groups, lawmakers jockey for changes as EPA nears final rule on eRIN market," *Waste Dive*	Dr. Michael Walsh
AA-51	New York State Energy Plan, *Low-Carbon Alternative Fuels* (Excerpt)	Dr. Michael Walsh
AA-52	New York State Energy Research and Development Authority, *Considerations for Low-Carbon Alternative Fuel Use in New York State* (Excerpt)	Dr. Michael Walsh
AA-53	Attachment to Discovery Response MECCUBDG-3.12a (Heat Pump Emissions tab)	Dr. Michael Walsh
AA-54	Attachment to Discovery Response MECCUBDG-3.12a (GHG Emissions Factors tab)	Dr. Michael Walsh
AA-55	RMI & National Grid, *Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization* (Excerpt)	Dr. Michael Walsh
AA-56	Discovery Response MECCUBDG-3.8a	Dr. Michael Walsh
AA-57	Discovery Response FLODG-4IV2bii	Dr. Michael Walsh
AA-58	Discovery Response AADG-2.7a	Dr. Michael Walsh
AA-59	Discovery Response AADG4.4a-f	Dr. Michael Walsh

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

Rick Brown, PE

Cell: 415-264-2122
Email: rick.brown.138@gmail.com

Career Overview

Deep technical and leadership experience in distribution, local transmission, backbone, and underground storage gas system planning, Gas Control operations, and pipeline simulation technology. Leadership of Gas System Planning for over 25 years including complex hydraulic analysis for unprecedented system outages to perform safety work on the gas system. Developed ideation and directed technical development of visionary planning technology including optimization software, parametric software to run thousands of simulations for operational and design optimization and operational intelligence, regulator station failure parametric analysis, advanced metering demand forecasting software, sensitivity analysis, and numerous transmission model loading improvements. International pipeline simulation industry recognition for both pipeline simulation technical expertise and leadership of the gas planning function, including Pipeline Simulation Interest Group Board of Directors and Author Coordinator for over 20 years. Authored and presented seven papers at PSIG and AGA. Significant experience in Rate Cases and other regulatory activities.

Experience

Consultant – Gas Decarbonization, Hydraulic Analysis — 11/2021-present

Independent consultant providing gas decarbonization and hydraulic analysis expertise. Develop strategies and approaches to analyze gas system decarbonization including hydraulic analysis approaches to retire gas assets, and critical factors for decarbonizing gas systems. Expert witness in multiple proceedings involving gas system investments, NPAs, and gas decarbonization.

Principal Gas System Planning Engineer – Gas System Planning — 3/2020-11/2021

New role to provide focus as the Gas System Planning lead for the complex decarbonization of PG&E gas systems. Developed process to prioritize portions of the gas system to potentially convert customers from gas to electric to reduce carbon emissions. Developed an overall strategy to address declining gas demand, methods to understand costs and revenues of individual gas systems and hydraulic analysis methodologies to retire portions of the gas system to reduce costs. Unique knowledge in an area of increased activity due to carbon reduction goals.

Senior Manager and Interim Director– Gas System Planning — 9/2014-3/2020

Led 70 +/- planning engineers in the local transmission and distribution planning function. Develop ideas and lead revolutionary planning process and technology improvements to improve hydraulic analysis accuracy/thoroughness, and engineer time efficiency to meet the needs of extensive system safety work. Led improvements on parametric studies for operational optimization of constrained gas systems, parametric studies for in-line inspection, system investments, and regulator station failure. Developed ideation and implemented a Gas System Operations organization wide program to repurpose gas systems with excess capacity to reduce costs and system risks yielding hundreds of millions of dollars of savings opportunities and significant risk reductions. Set direction for extensive improvements in gas planning processes and technology including automated advanced metering utilization, improved demand accuracy, and model loading improvements.

As Interim Director for two years led group of 100 +/- planning engineers. Continued technical and process vision from Senior Manager role, advocated the role of the planning function and educated other directors of the role. Led underground storage strategy and efforts to improve system outage planning.

Manager – Gas System Planning — 1999-9/2013

Multiple gas planning manager roles with increasing levels of leadership and responsibility. Local Transmission and Distribution Planning (6/12-9/13, 32 engineers), Transmission System Planning & Gas

Planning Support (2006-2012, 16 direct report engineers), and Transmission System Planning (1999-2006, 12 direct report engineers).

Developed a team culture to provide high quality accurate hydraulic analysis, long-term cost-efficient system investments, and extensive system expertise to support reliable, optimum operations. Drove team to develop of state-of-the-art gas planning technology and process improvements. Promote environment of trust, honesty, openness, and employee recognition. Influenced and implemented the combining of transmission and distribution planning engineers into one focused planning organization. Led planning analyses to support unprecedented levels of pipeline safety work and pressure reductions. Led optimization of system investments resulting in over $200 million in capital savings. Four-time Rate Case expert witness.

Principal Gas Engineer, Senior Gas Engineer – Gas Control 1993-1999

- Increasing levels of technical expertise and leadership from Senior Engineer (1993-1997) to Principal Engineer (1997-1999)
- PG&E and industry recognized expert for hydraulic and operational analysis for backbone and underground storage gas transmission systems.
- Visionary development of custom VBA/Excel operations optimization modeling applications for use by Gas Control Operators. Robust, user friendly tools minimized energy use and flow capacity while running hundreds of simulation scenarios. Applications used for over a decade for majority of backbone simulations.

Gas Engineer – Gas Control and Golden Gate Region 1986-1993

- Provided direct hydraulic engineering support to Gas Control leadership and operators.
- Provided expert hydraulic operations support PG&E backbone systems. Performed complex modeling of compressor stations, transient backbone operations, and underground storage operations..

Professional Memberships

Registered Professional Mechanical Engineer – State of California

Board Member and Conference Author Coordinator - Pipeline Simulation Interest Group (PSIG), 1997 to present

Presented 7 papers at PSIG and one at AGA:

- 2022 - Gas decarbonization in California and impacts on hydraulic analysis methodologies
- 2022 – Parametric studies and practical business benefits
- Custom energy minimization software used by gas control operators (voted best paper)
- Compressor/turbine performance monitoring software (3rd best paper)
- Software to run hundreds of hydraulic simulations (parametric study) automatically (runner up best paper)
- Demand uncertainty and the need for sensitivity analysis (runner up best paper)
- Pipeline safety impacts on gas system planning (voted best paper)

Education

California Polytechnic State University San Luis Obispo, CA
B.S., Mechanical Engineering

References

Available on request.

Interests

Home improvement, camping, hiking, travel, youth sport coaching

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.10ei	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding the existing 8” Petoskey Pipeline requiring a second, redundant pipeline to address customer service reliability during the ILI.

e. Please describe all actions the Company has taken to address any potential obstructions that could cause the ILI tool to become stuck, including the following:

i. Has the Company reviewed its records to identify diameter changes, fittings, tees, elbows, and any other physical characteristics that could potentially cause an ILI tool to become stuck and made physical modifications to the pipeline to minimize the chance of a stuck ILI tool?

Answer: Yes, pipeline modifications have been made to reduce the likelihood of a stuck tool but pipeline characteristics are not the only thing that could cause a tool to get stuck. For example, excessive debris built up in the line over the many years of being in service could potentially cause a tool to get stuck.

Attachment: None

MPSC Case No: U-21973
Requester: Ann Arbor
Question No.: AADG-3.8c
Respondent: K. M. Fedele
Page: 1 of 1

Question: Please provide information regarding actions the Company takes to help minimize the impacts on customer service in the rare event there is damage to the existing 8” Petoskey Pipeline.

c. Does the Company have an emergency response plan for the 8” Petoskey Pipeline to quickly isolate any damage to the pipeline and make emergency repairs?

Answer: Yes.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.11a	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please refer to the Direct Testimony of K. M. Fedele, p. 39, lines 12-13 stating that LNG is costly, complex, and impractical if an ILI tool were to become stuck.

a. Please provide the estimated cost to provide LNG during the ILI operation.

Answer: Estimated cost to provide LNG in the event of a stuck ILI tool is $5.5 million. This assumes the LNG vendor would be on set up and on stand by for 7 days while the ILI occurs. If there were a stuck tool, we assume that injection would be on for 14 days to feed the system

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.9a	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding the existing 8" Petoskey Pipeline requiring a second, redundant pipeline to address customer service reliability in the event of a pipeline failure.

a. How many incidents have occurred during the pipeline's life that created a risk of a pipeline failure?

Answer: To the best of my knowledge, there have been no incidents to date that could have led to a failure.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.6g	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: For the following requests regarding the East Petoskey Pipeline Reinforcement project, please provide the following information regarding the existing 8" Petoskey Pipeline:

g. Please provide leak data for the past 5 years including count of leaks by leak grade.

Answer: There have been no leaks in the past 5 years.

Attachment: None

MPSC Case No: U-21973
Requester: Ann Arbor
Question No.: AADG-3.6h
Respondent: K. M. Fedele
Page: 1 of 1

Question: For the following requests regarding the East Petoskey Pipeline Reinforcement project, please provide the following information regarding the existing 8” Petoskey Pipeline:

h. Please provide any data regarding corrosion issues.

Answer: No additional data is available.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.9b	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding the existing 8” Petoskey Pipeline requiring a second, redundant pipeline to address customer service reliability in the event of a pipeline failure.

b. Has the pipeline ever had to be isolated due to damage? Did customers lose service and if so, how many customers? If customers did not lose service, please explain why customers did not lose service.

Answer: No.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.7b	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding the risk of third party or natural forces that could cause a failure in the existing 8” Petoskey Pipeline.

b. How often is the pipeline patrolled? How often is the pipeline aerial patrolled?

Answer: Pipeline is patrolled annually for Pipeline Density Survey with leak survey of road/railroad crossings semi-annually. It is aerial patrolled bi-weekly, twenty-four times per year.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.7aiv	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding the risk of third party or natural forces that could cause a failure in the existing 8" Petoskey Pipeline.

a. Please provide a description of the route of the pipeline from Boyne City Gate Station including:

iv. A fair amount of the pipeline route is on open land. Is the land used for farming or livestock grazing? Does the Company have a program to educate and provide farmers or ranchers or other landowners about the presence of the pipeline on their land and the need to contact 811 before they dig on their land?

Answer: There is approximately five miles of the pipeline that is used for farming and/or livestock grazing. DTE Gas sends annual informational safety mailers to all landowners within 660' either side of the pipeline. Also, DTE Gas also sends an annual mailing specifically to farmers along the pipeline right-of-way. Both cover 811 requirements.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.7aiii	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding the risk of third party or natural forces that could cause a failure in the existing 8” Petoskey Pipeline.

a. Please provide a description of the route of the pipeline from Boyne City Gate Station including:

iii. Are pipeline markers present along the entire pipeline’s route?

Answer: Yes, aside from within the farmland. At farmland, markers are at the boundary points to designate the pipeline location at each edge. If farmers allow for markers, they are maintained within the farmed area.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.8ei	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding actions the Company takes to help minimize the impacts on customer service in the rare event there is damage to the existing 8" Petoskey Pipeline.

e. Has the Company hydraulically modeled the survival time of the pipeline to provide service to customers in the event of a pipeline failure under the following conditions?

i. A range of temperature conditions across the year in addition to extreme cold conditions.

Answer: No.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.8eii	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding actions the Company takes to help minimize the impacts on customer service in the rare event there is damage to the existing 8” Petoskey Pipeline.

e. Has the Company hydraulically modeled the survival time of the pipeline to provide service to customers in the event of a pipeline failure under the following conditions?

ii. Isolation of the damaged section to limit the loss of gas as described in 8a above.

Answer: No.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.8eiii	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding actions the Company takes to help minimize the impacts on customer service in the rare event there is damage to the existing 8” Petoskey Pipeline.

e. Has the Company hydraulically modeled the survival time of the pipeline to provide service to customers in the event of a pipeline failure under the following conditions?

iii. The increase in survival time if additional mainline valves were installed on the pipeline.

Answer: No.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.8eiv	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding actions the Company takes to help minimize the impacts on customer service in the rare event there is damage to the existing 8" Petoskey Pipeline.

e. Has the Company hydraulically modeled the survival time of the pipeline to provide service to customers in the event of a pipeline failure under the following conditions?

iv. The increase in survival time if mainline valves had remote control capability.

Answer: No.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.8ev	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding actions the Company takes to help minimize the impacts on customer service in the rare event there is damage to the existing 8” Petoskey Pipeline.

e. Has the Company hydraulically modeled the survival time of the pipeline to provide service to customers in the event of a pipeline failure under the following conditions?

v. The increase in survival time if portable CNG or LNG was connected to the pipeline.

Answer: No.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-3.8evi	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Please provide information regarding actions the Company takes to help minimize the impacts on customer service in the rare event there is damage to the existing 8" Petoskey Pipeline.

e. Has the Company hydraulically modeled the survival time of the pipeline to provide service to customers in the event of a pipeline failure under the following conditions?

vi. The reduction in repair time if emergency response plans were developed and implemented including all resources both crews and material are planned for.

Answer: No.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-2.3a	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: For the following requests, please refer to the Fort Street Main Replacement project summary in Exhibit A-12, Schedule B5.5, p. 4-5.

a. The Scope of Work section provides data that shows in 2025 the Company will replace 14,925 feet (2.83 miles) of pipe at a project cost with contingency of $27,000,000. Since a portion of the cost is for 4 regulators and miscellaneous main, valves, and fittings, please provide the cost only for the 2.83 miles of new pipe. Does the Company find this project to have a higher than typical cost per mile of pipe replaced? Please explain why or why not.

Answer: The Company cannot provide total costs for only the 2.83 miles of new pipe on the Fort Street Main Replacement project in 2025 because costs associated with design, materials, and other project overheads are tracked by phase and year. However, the Company does find that the Fort Street Main Replacement project does have a higher than typical cost per mile of pipe replaced due to many factors including: large diameter steel pipeline construction, multiple large horizontal directional drills and auger bores, unmarked facility reroutes, historic trolley track removal, increased traffic control costs, cost for flowable filling large diameter abandoned pipelines, and additional costs for coordinating with large customers, the GHIB project, other MDOT projects, and local events.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-2.3b	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: For the following requests, please refer to the Fort Street Main Replacement project summary in Exhibit A-12, Schedule B5.5, p. 4-5.

b. The Scope of Work section provides data that shows in 2026 and 2027 the Company will replace 12,234 feet (2.32 miles) of pipe at a project cost with contingency of $55,000,000. Since a portion of the cost is for 1 regulator and miscellaneous main, valves, and fittings, please provide the cost only for the 2.32 miles of new pipe. . Does the Company find this project to have a higher than typical cost per mile of pipe replaced? Please explain why or why not.

Answer: Please refer to question AADG-2.3a

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-5.1d	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: For the following request regarding the proposed Carlton Main Replacement project please refer to AADG-2.1ai-xi and AADG-2.1bi-x which requested a map or gas system schematic with information that was needed to understand the operation and hydraulics of the existing Carlton Main and the proposed 12" replacement main, and both mains' integrated operation with upstream and downstream pipelines, pipeline flow directions, operating pressures and other requested information. Since the information requested was not provided, please provide the following:

d. Please provide justification for the replacement main being 12" rather than the same diameter as the existing 8" main. Please justify why a flow area and capacity increase of approximately 120% is needed.

Answer: As discussed on pages 59 and 60 of my direct testimony, the proposed 12-inch replacement main integration will provide supply redundancy to the 274 psig system from both Willow Gate Station and Sumpter Gate Station. Per page 61 in my direct testimony, it explains why replacement of the Carlton line with 12" main at 274 psig represents the optimal solution.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-2.1h	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: For the following requests, please refer to the Carlton Main Replacement project summary in Exhibit A-12, Schedule B5.5, pages 13-14, and the Direct Testimony of K. M. Fedele, p. 58-62.

h. To address the risk of a portion of the Carlton Main requiring lengthy repairs due to the need for long lead time mechanical fittings, has the Company considered stocking spare mechanical fittings? If yes, please explain why this option was not pursued.

Answer: Following field verification (during a planned project) of the thin-wall pipe using non-destructive testing, the company has included long-lead mechanical fittings in inventory for the 6-inch section identified for replacement on the Carlton Main project. Although these fittings are stocked for emergency use, there are concerns installing and operating heavy mechanical fittings on thin-walled steel pipe. Welding is the preferred connection method for long-term pipeline serviceability.

Attachment: None

MPSC Case No: U-21973	
Requester: AG	
Question No.: AGDG-3.113	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: Refer to page 59 of Ms. Fedele's direct testimony on the Carlton Main Replacement project. Please identify what problems have occurred on this main in each of the past five years. Provide the number of gas leaks and repairs performed in those years.

Answer: The section of the Carlton Main to be replaced has not had any known gas leaks or repairs performed on it in the last 5 years.

In 2022 on the southern section of the Carlton, the Sherwood and Willow System Reliability district replacement project design required a field change resulting in construction delays due to NDT X-Rays indicating the 6" pipe thickness as low was 0.172". Given these readings, the project was redesigned at additional cost to avoid welding to the 6" Carlton pipeline.

Future projects on the Carlton main will be designed without the use of welded connections which results in more complex and costly repairs and compromises long term reliability as described on page 59 of Witness Fedele's testimony.

Attachment: None

MISSY STULTS, PHD

URBAN CLIMATE CHANGE EXPERT

I am an urban sustainability and climate change practitioner with over 15 years experience helping make local communities more resilient and livable.

RECENT PROFESSIONAL HISTORY

SUSTAINABILITY AND INNOVATIONS DIRECTOR

CITY OF ANN ARBOR, MI | JUL 2018 - PRESENT

- Design, manage, and implement the community's transition to carbon neutrality in a just and equitable manner by the year 2030.
- Manage 11 full time staff, multiple interns, and temporary employees
- Build and foster a coalition of community stakeholders to support the City's carbon neutrality and resilience work.
- Develop policies, programs, and initiatives to achieve goal.

NETWORK FOUNDER AND MANAGER

SCIENCE TO ACTION NETWORK | JAN 2017 - JUL 2018

- Founder and manager of a network of networks,composed of over 80 nonprofits, academic institutions, professional societies,for-profits, and former federal employees, focused on saving and advancing evidence-based decision-making as it pertains to climate action, environmental protection, and the production and use of science.
- Responsible for network fundraising, coordination, training, and recruitment.

PROGRAM OFFICER

THE CLIMATE RESILIENCE FUND| FEB 2016 - JUL 2018

- One of two staff working to launch a new philanthropy to invest in climate resilience initiatives in the United States. Includes actively seeking investments from existing foundations and venture capitalists, organizing a philanthropic working group on climate change adaptation, and building strategic partnerships with foundations, federal agencies, nonprofits, and for profit.

CLIMATE AND SUSTAINABILITY CONSULTANT

STULTS CONSULTING | FEB 2013 - JUL 2018

- Assisted The Kresge Foundation with designing and implementing evaluations of select grantees.
- Led development of a climate curriculum for The Kresge Foundation's partners, grantees, staff, and the public.
- Conducted evaluation for how professional societies integrate climate change into member engagement.

Contact Information

734-794-6430

301 E. Huron Street
Ann Arbor, MI 48104

mstults@a2gov.or

LinkedIn: https://www.linkedin.com/in/melissa-stults-959a348/

Professional Service

- Board Member, American Society of Adaptation Professionals
- Board Member, Southern Climate Impacts and Planning Program
- Member, Sierra Club Adaptation Strategy Development Working Group
- Advisory Board Member, Notre Dame Global Adaptation Index
- Advisory Board Member, Resilient Communities for America
- Advisory Board Member, Adaptation International
- Member, National Disaster Resilience Competition Advisory Committee
- Co-Editor in Chief, Michigan Journal of Sustainability
- Member, Advisory Panel for the United Nations Strategy for Disaster Reduction

Public Service

- Board Member, Ann Arbor YMCA
- Member, Washtenaw County Environmental Commission
- Committee Member, Michigan Environmental Rules Review Committee
- Member, City of Ann Arbor Climate Action Partnership Committee
- Commissioner, City of Ann Arbor Transportation Commission
- Commissioner, City of Ann Arbor Parks Advisory Commission
- Commissioner, City of Ann Arbor Environmental Commission
- Co-Chair, Ann Arbor Dog Park Sub-Committee
- Alumni Council Member, University of New England

CLIMATE AND SUSTAINABILITY CONSULTANT (CONT)

STULTS CONSULTING | FEB 2013 - JUL 2018

- Led development of a climate and socio-economic vulnerability assessment tool for Great Lakes and Mid-Atlantic communities.
- Assisted the City of Aspen, CO, Upper Snake River Tribe Foundation, Miami, OK, 1854 Ceded Territory, Jamestown S'Klallam Tribe, and North Olympic Peninsula Resource Conservation and Development District in the creation of a climate adaptation strategy.
- Co-developed a planning process that led to community-wide sustainability plan for the City of San Antonio.
- Co-developer of research protocol to assess the state of community-based adaptation activities in the United States in partnership with Abt Associates.
- Co-creator of the adaptation certification criteria for the New York State Climate Smart Communities program.
- Co-developed and delivered workshops in the San Francisco Bay area and New Orleans for communities recognized in the Rockefeller Foundation 100 Resilient™ Cities program.
- Co-developed agendas and support material and co-led a series of Climate Leadership Academies focused on climate adaptation activities for U.S. local government stakeholders.
- Organized and facilitated workshop to help Schneider Electric develop a new suite of climate and sustainability services for local government clients.

EDUCATIONAL BACKGROUND

DOCTORATE, URBAN RESILIENCE

UNIVERSITY OF MICHIGAN| OCT 2016

MASTERS, CLIMATE AND SOCIETY

COLUMBIA UNIVERSITY| AUG 2005

BACHELORS, MARINE BIOLOGY & ENV. SCIENCES

UNIVERSITY OF NEW ENGLAND| MAY 2004

SAMPLE PUBLICATIONS

- Stults,M. 2017. Integrating climate change into hazard mitigation planning: Opportunities and examples in practice. Climate Risk.
- Stults,M. & Woodruff, S.C. 2016.Looking under the hood of local adaptation plans: shedding light on the actions prioritized to build local resilience to climate change. Mitigation and Adaptation Strategies for Global Change.
- Woodruff, S.C. & Stults, M. 2016. Planning to be Prepared: Assessing the Content and Quality of U.S. Local Climate Adaptation Plans. Nature Climate Change. 1-13.
- Meerow, S., Newell, J., & Stults, M. 2016. Defining Urban Resilience: A Review. Landscape and Urban Planning. 147: 38-49.
- Meerow, S. & Stults, M. 2016. Comparing conceptualizations of urban climate resilience in theory and practice. Sustainability. 8(7): 701.

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-2.9gi-iv	
Respondent: H. J. Decker	
Page: 1 of 2	

Question: Please provide responses to the following requests regarding climate goals and decarbonization strategy.

g. In the last rate case, Dr. Bente Villadsen identified franchise negotiations with Ann Arbor as an example of a business risk due to decarbonization. Case No. U- 21291, 4 Tr 2494.

i. What is the Company's current view of the business risk associated with the resulting franchise?

ii. If the signing of the franchise agreement with Ann Arbor reduced the risk identified by Dr. Villadsen, how does the Company weigh the risk of the shorter-than-typical term of the franchise?

iii. If the signing of the franchise agreement with Ann Arbor maintained the risk identified by Dr. Villadsen, how was that risk incorporated into this case?

iv. What is the Company's view of business risks associated with other franchises in its service territory?

Answer: DTE Gas objects for the reason that the information requested is not relevant or proportional to the needs of the case. Subject to this objection, and without waiving this objection, DTE Gas would answer as follows:

i./ii./iii./iv. Refer to Q/A 35 of my direct testimony which states, "DTE Gas acknowledges that State or Federal legislative and regulatory developments could impact natural gas demand and DTE Gas's capital plans. DTE Gas is prepared to identify the most effective method for delivering safe and affordable natural gas to our customers in alignment with any legislative or regulatory developments. DTE Gas is not currently aware of any proposed legislation or regulation that would materially impact its current business." The Company sees the franchise agreement with Ann Arbor and its associated Agreement on Climate Action as a means for delivering safe and affordable natural gas to our customers. The shorter-than-typical term of the Ann Arbor franchise is a reflection of the challenges Ann Arbor faces reducing emissions to meet the City's ambitious climate goals. DTE Gas views the current franchise agreement as an opportunity to work with the City to

Co-Respondent(s): Legal

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-2.9gi-iv	
Respondent: H. J. Decker	
Page: 2 of 2	

continue to evaluate different emission reduction options and identify solutions that can meet customer needs for affordability and reliability. The Company will continue to provide all customers with the natural gas it needs safely, reliably, and affordably and work collaboratively with municipalities as requested.

Attachment: None

Co-Respondent(s): Legal

City of Ann Arbor

301 E. Huron St.
Ann Arbor, MI 48104
http://a2gov.legistar.com/Calendar.aspx

Legislation Details (With Text)

File #:	23-0382	**Version:** 1		**Name:**	3/20/23 Resolution Directing the City Administrator to Begin Negotiating a New Natural Gas Franchise
Type:	Resolution			**Status:**	Passed
File created:	3/20/2023			**In control:**	City Council
On agenda:	3/20/2023			**Final action:**	3/20/2023
Enactment date:	3/20/2023			**Enactment #:**	R-23-101

Title: Resolution Directing the City Administrator to Negotiate a New Natural Gas Franchise

Sponsors:

Indexes:

Code sections:

Attachments:

Date	Ver.	Action By	Action	Result
3/20/2023	1	City Council	Approved	Pass

Resolution Directing the City Administrator to Negotiate a New Natural Gas Franchise
While researching the City's opportunities related to beneficial electrification, limiting new natural gas connections, and achieving the A^2ZERO goal of community-wide carbon neutrality by 2030, City staff reviewed the City's natural gas franchise (Ann Arbor City Code, Chapter 34) and noted that it is set to expire in 2027. Under Michigan law, a franchise is a contract between a local unit of government and a utility that: (i) governs the use of the public rights of way, and (ii) sets the conditions under which the company may, for a set period, provide the specified utility service. Franchises can also include additional terms and several local governments across the country (e.g., Chicago, Salt Lake City, and San Diego) have successfully advanced affordability, equity, and clean energy goals via franchise negotiations while optimizing use of the public rights of way.

Given the City's aggressive and time sensitive A^2ZERO goals, the community's desire for more resilient, reliable, and affordable energy, and the need to accomplish these ends in a legally prudent manner, staff request Council authorization to begin negotiations immediately with the goal of bringing a new franchise aligned with A^2ZERO and best practices regarding the use of the City's rights of way, back to Council as soon as possible.

Budget/Fiscal Impact: Budget currently exists within the Office of Sustainability and Innovations to fund legal support services to advance this work.
Prepared by: Missy Stults, Sustainability and Innovations Director
Reviewed by: Atleen Kaur, City Attorney
Approved by: Milton Dohoney Jr., City Administrator
Whereas, In 1997 the City of Ann Arbor granted a non-exclusive franchise to Michigan Consolidated Gas Company, a subsidiary of DTE, to supply and sell natural gas within the City of Ann Arbor for a period of 30 years;

Whereas, This franchise for natural gas is set to expire in 2027, but is also revocable at will;

Whereas, The Ann Arbor City Council has adopted A^{2}ZERO, setting the goal of community wide carbon neutrality by the year 2030, including the sub-strategy of supporting beneficial electrification and an incremental transition from natural gas to electric transportation and building systems;

Whereas, The City and all utilities, including DTE Gas, that use the rights of way to provide utility service would benefit from improved communication and practices regarding the use of the City's rights of way;

Whereas, Ann Arbor City Council recognizes the urgency in identifying and implementing thoughtful and innovative approaches to meet the City's goals;

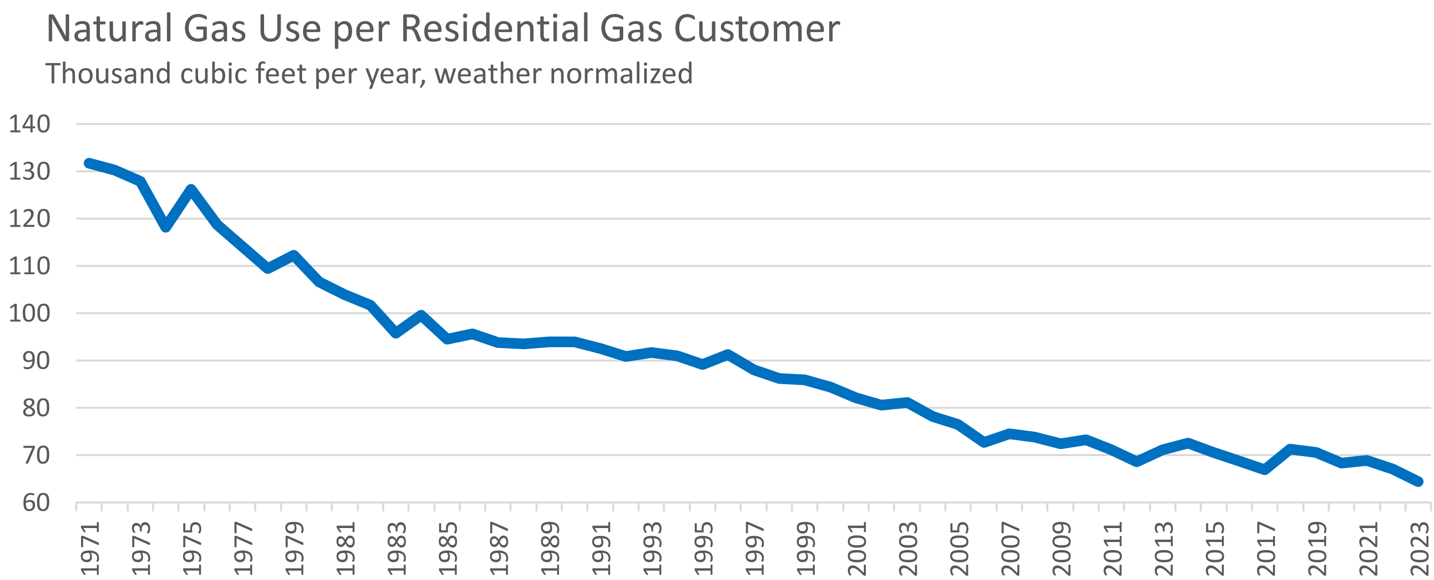
RESOLVED, That Ann Arbor City Council directs the City Administrator to begin negotiating a new or amended natural gas franchise;

RESOLVED, That Ann Arbor City Council directs the City Administrator to ensure that any new or amended proposed franchise is aligned, to the fullest extent possible, with the City's A^{2}ZERO goals and best practices regarding uses of the City's rights of way, without compromising the ability of community members to heat or cook in their homes and businesses; and

RESOLVED, That the City Administrator be authorized to take all necessary administrative actions to implement this resolution.

Energy Insights

Natural Gas Use per Residential Customer

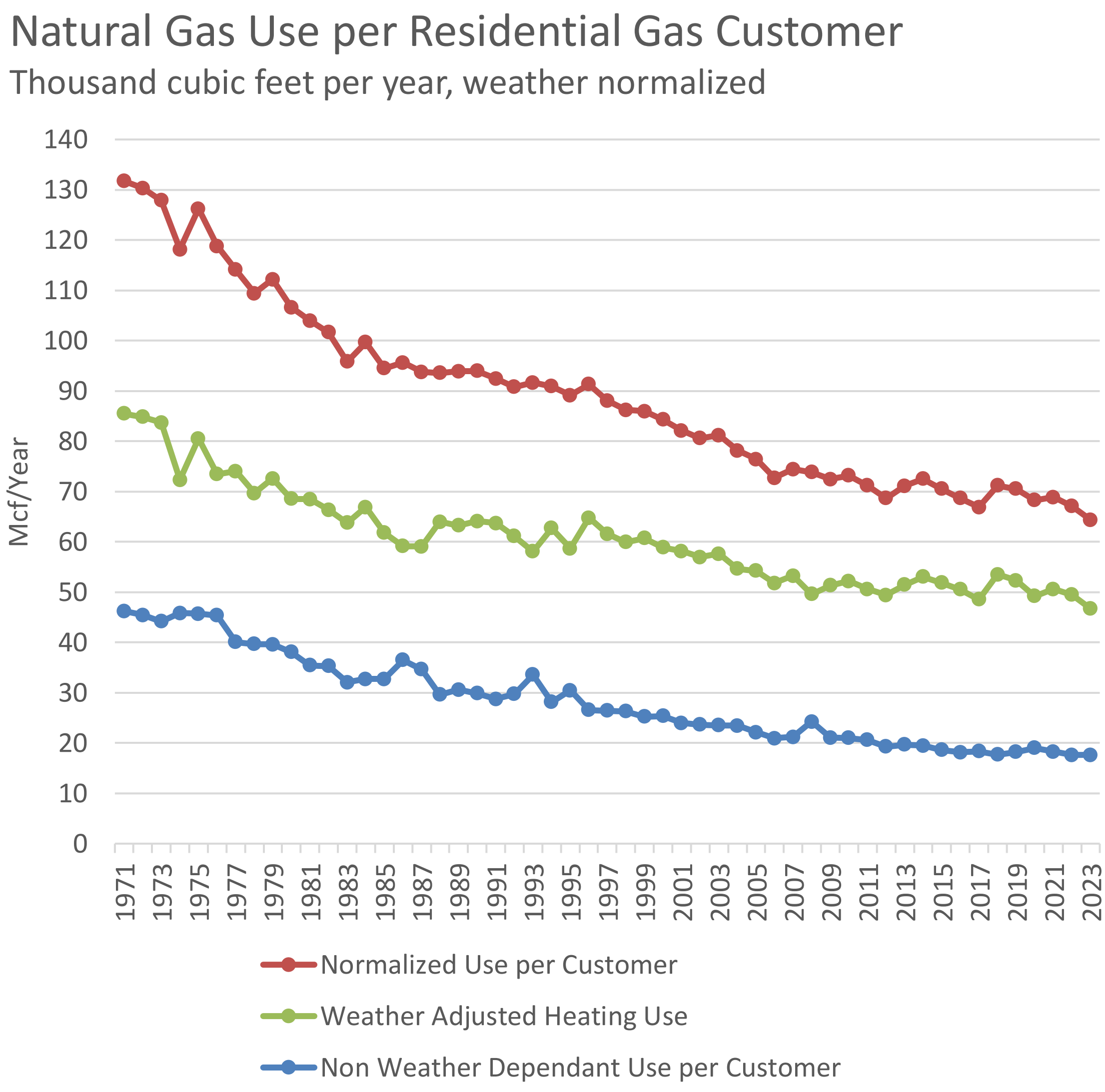


- Normalized natural gas use per residential gas customer fell 51% between 1971 and 2023, or 1.34% per year for 53 years.
- Since 2020, use per customer has declined faster than the previous decade average (1.45% versus 0.69%). 2023 alone declined by 4.0%. Historical annual rates of decline are as follows:
  - 1970–1979: 1.06%
  - 1980–1989: 1.26%
  - 1990–1999: 0.89%
  - 2000–2009: 1.51%
  - 2010–2020: 0.69%
  - 2020–2023: 1.45%
- Non-weather-dependent appliances such as cooking stoves, water heaters, and dryers have experienced significant reductions in average natural gas consumption per customer. Non-weather-dependent use of natural gas per customer has declined at an average annual rate of 1.80% since 1971.
- Despite the significant decline in normalized use per customer in 2023, the total number of households with natural gas grew by **1%** from 72.52 million to 73.23 million.

Supplemental Materials from AGA's Normalized Use per Customer Model

Methodology

- Non-weather-dependent appliance volumes are assumed to match the average consumption during July and August, with the excess consumption in other months assumed to be weather-sensitive.
- Weather-sensitive heating demand is normalized by multiplying load by the ratio of 30-year normal heating degree days over actual annual calendar heating degree days.



Source: Based on data from Energy Information Administration and NOAA Utility Weighted Heating Degree Data.
AGA Contact: Brendan O'Brien (bobrien@aga.org) 202-824-7220.

RMI

TOOL | 2026

Tracking the Heat Pump & Water Heater Market in the United States

This data hub spotlights publicly available national HVAC and water heating shipment data from the Air Conditioning, Heating, & Refrigeration Institute (AHRI). Heat pump appliances play a vital role in the clean energy transition and lowering building emissions due to their ability to efficiently provide heating and cooling while replacing the use of onsite fossil fuels. Monthly charts reflect the average of the previous 12 months to remove seasonal variations. This page will be updated every 3 months.

Last updated: February 2026

Tracking Period: January-December 2025

3.6M

heat pump space heaters sold

12%

higher heat pump sales compared to gas furnace sales

47%

of air conditioners sold were heat pumps

54%

of water heaters sold were electric

Heat Pumps for Space Heating

Heat pumps have outsold gas furnaces consistently since 2021. In 2025, manufacturers shipped 12% more heat pumps than gas furnaces (3.6M units versus 3.2M units). Heat pumps are averaging 3.9 million sales this decade, compared to 3.5 million average annual sales of gas furnaces

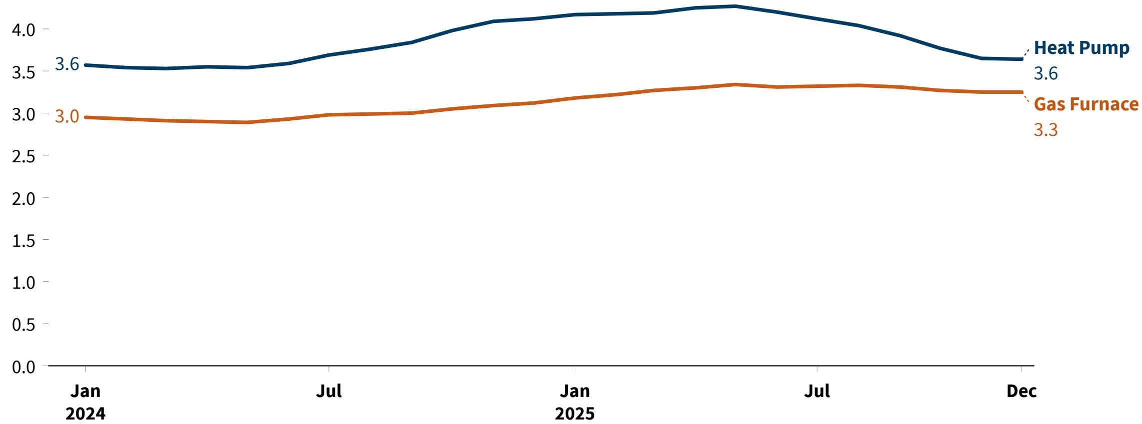
Market factors continue to influence heat pump sales. All residential and light commercial air conditioners and heat pumps manufactured after January 1st, 2025 must use A2L refrigerants. This phase-in may have contributed to a surge in heat pump sales in 2024, as manufacturers rushed to ship systems using R-410a refrigerant to distributors and customers. The transition has introduced uncertainty into the HVAC market, with reports of shortages of A2L refrigerants, but heat pumps outsold gas furnaces in 2025 despite the uncertainty.

Over the past 20 years, annual heat pump sales have increased by 70% whereas gas furnace sales have decreased by 7%.

TRAILING MONTHLY DATA MONTHLY DATA

Sales of Air-Source Heat Pumps for Space Heating Compared to Gas Furnaces

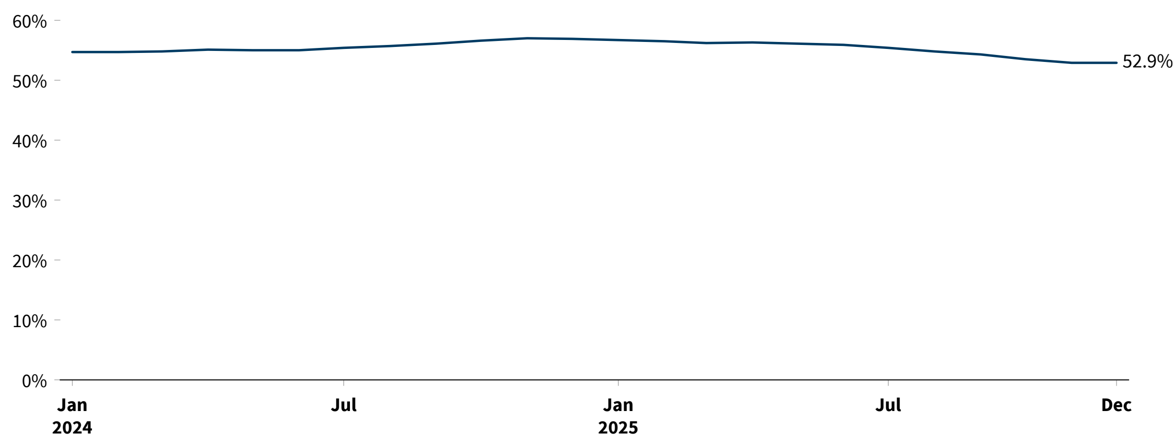
Total # of units shipped (millions of units), trailing 12 months



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Relative Share of Heat Pumps for Space Heating

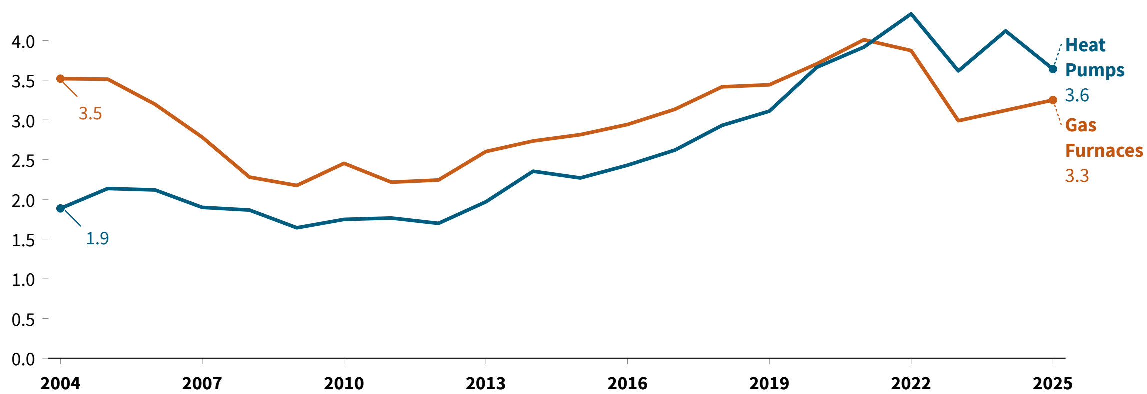
% of leading space heating equipment shipments that are air source heat pumps, trailing 12 months



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Annual Shipments of Gas Furnaces and Air-Source Heat Pumps

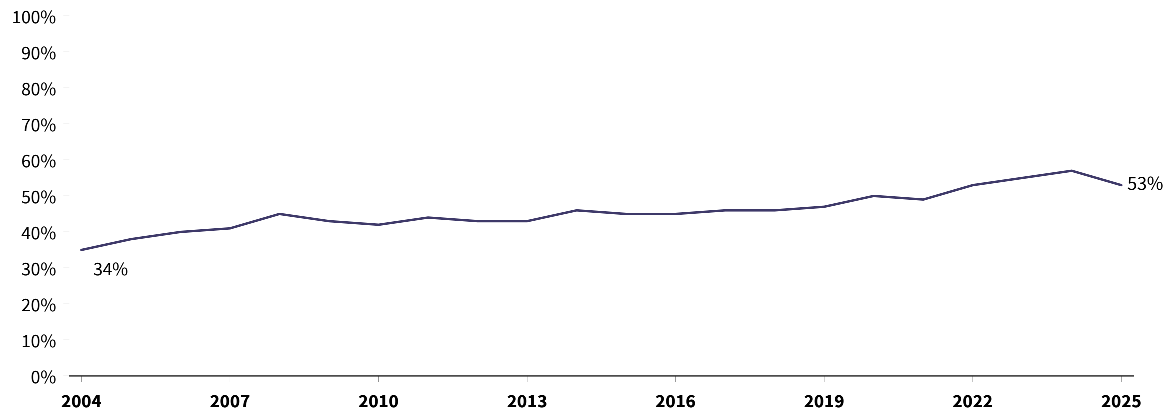
Annual # of units shipped (millions of units), 2004-2025



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Relative Share of Air-Source Heat Pumps

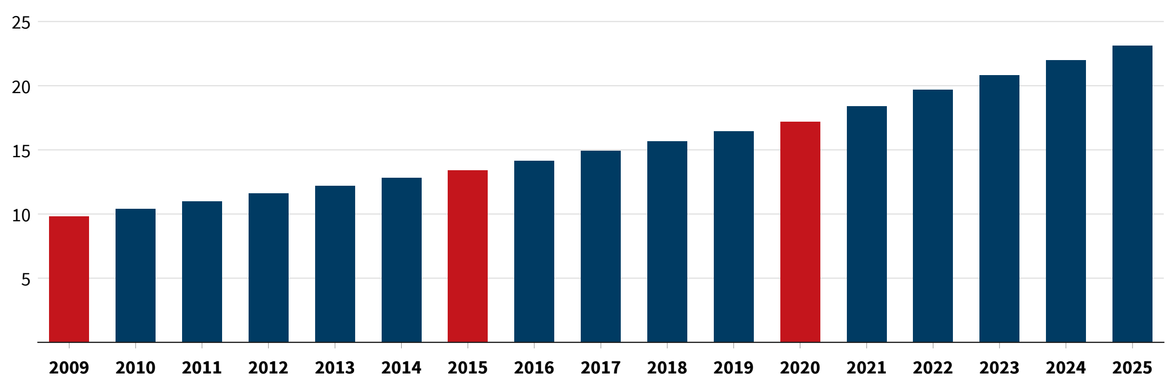
% of leading space heating equipment shipments that are air-source heat pumps, 2004-2025



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Stock of Heat Pumps for Residential Space Heating

Estimated stock of heat pumps for residential space heating, millions of units



Values in red are drawn from EIA's Residential Energy Consumption Survey (RECS), values in blue are estimates based on available heat pump shipment data and extrapolations from RECS data.

Get the data • Download image

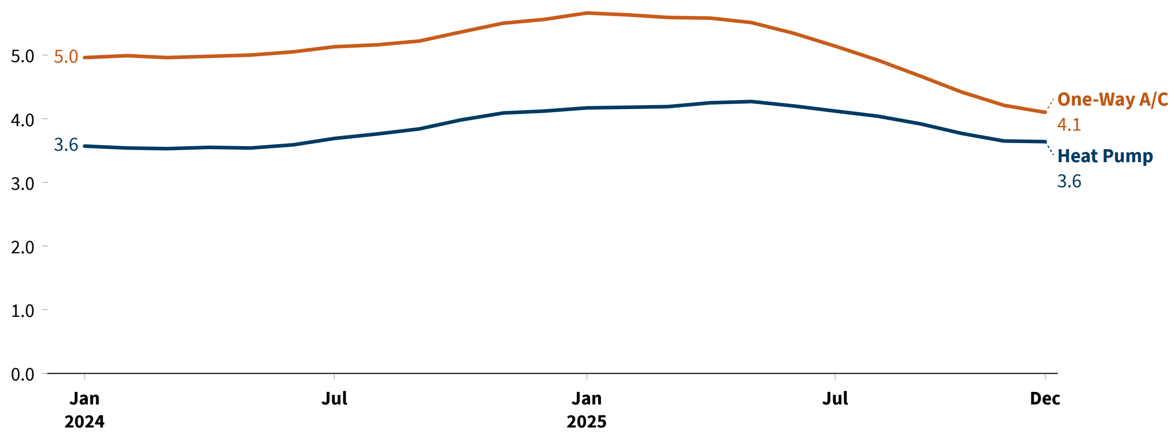
Heat Pumps for Cooling

Heat pumps are a two-in-one heating and cooling solution. Buyers of cooling equipment typically choose between heat pumps and traditional, one-way air conditioners. Over the past 10 years, heat pumps have increased in monthly market share of residential cooling equipment from 33% to 47%. In 2025, heat pumps made up 47% of cooling equipment sales, and for the first time ever, outsold one-way ACs in October, November, and December.

TRAILING MONTHLY DATA MONTHLY DATA

Sales of Residential Heat Pumps for Cooling

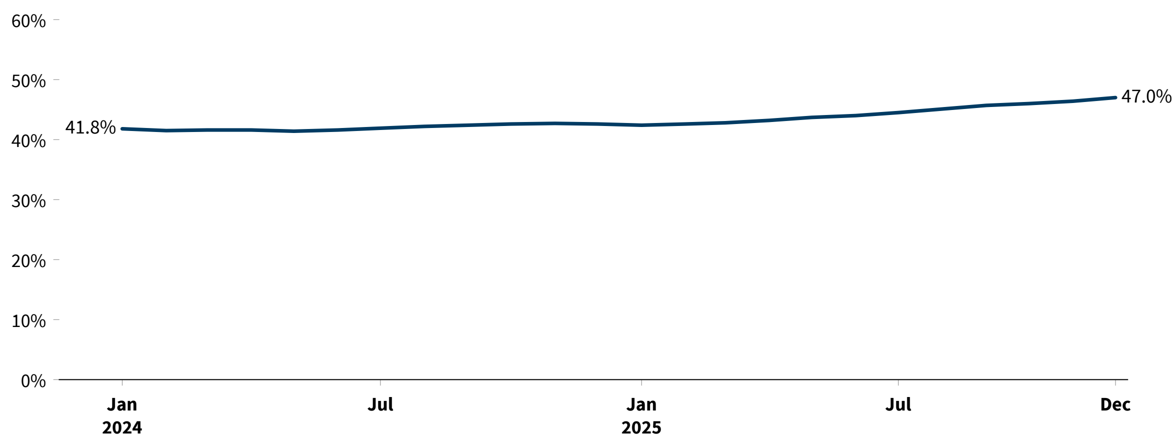
Total # of units shipped (millions of units), trailing 12 months



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Relative Share of Residential Heat Pumps for Cooling

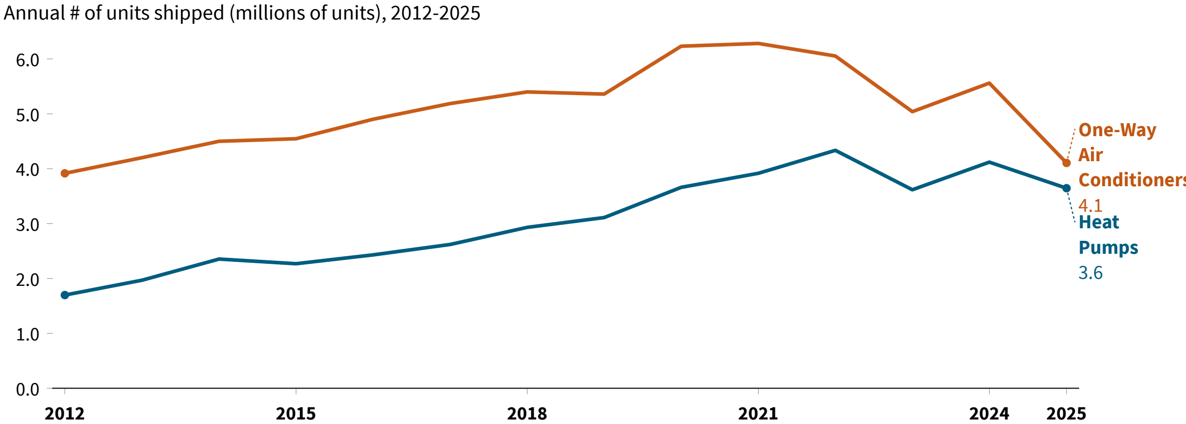
% of A/Cs that are heat pumps, trailing 12 months



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Annual Shipments of Air Conditioners

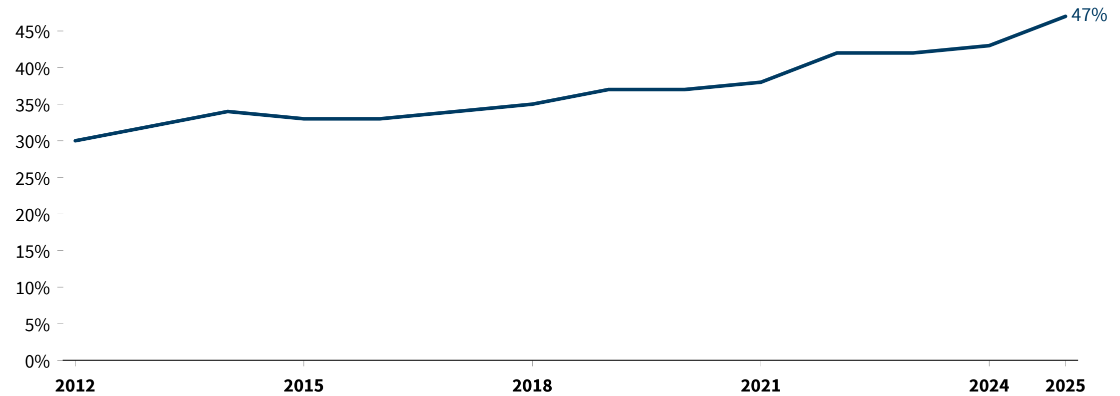
Annual # of units shipped (millions of units), 2012-2025



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Market Share of Air Conditioners

% of A/Cs that are heat pumps, 2012-2025



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Water Heaters

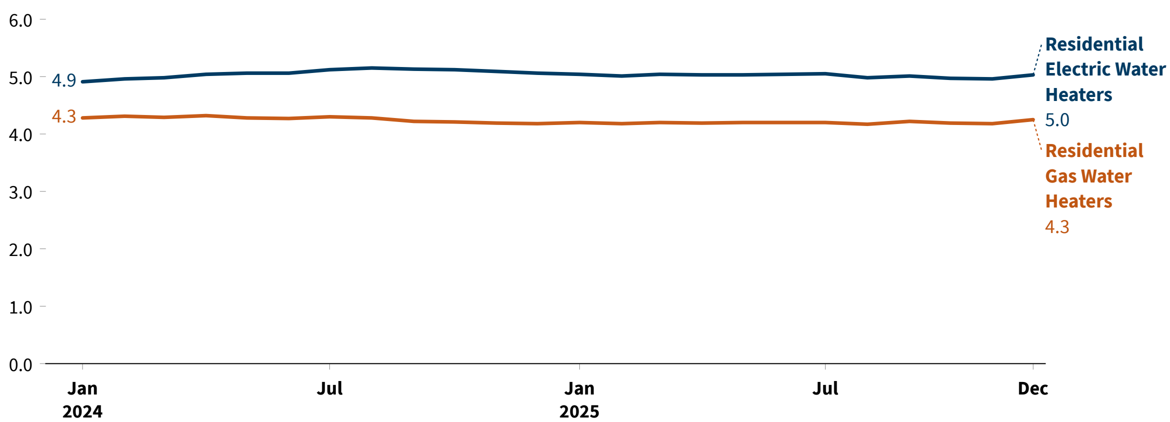
Electric water heaters continue to make up the majority of both residential and commercial water heater shipments, maintaining a market share of 54% between 2024 and 2025. Electric water heaters had their second best sales month ever in December 2025 after setting the record in March 2025. The water heater market is generally less volatile than the space heating market.

While shipment and market share data is more limited specifically for heat pump water heaters, ENERGY STAR data suggests that heat pump water heaters made up 4% of residential electric water heater sales in 2023. ENERGY STAR data collection for 2024 and 2025 have not been published, and a release date has not been announced. The charts below will be updated when the data are available.

TRAILING MONTHLY DATA MONTHLY DATA

Sales of Residential Electric & Gas Water Heaters

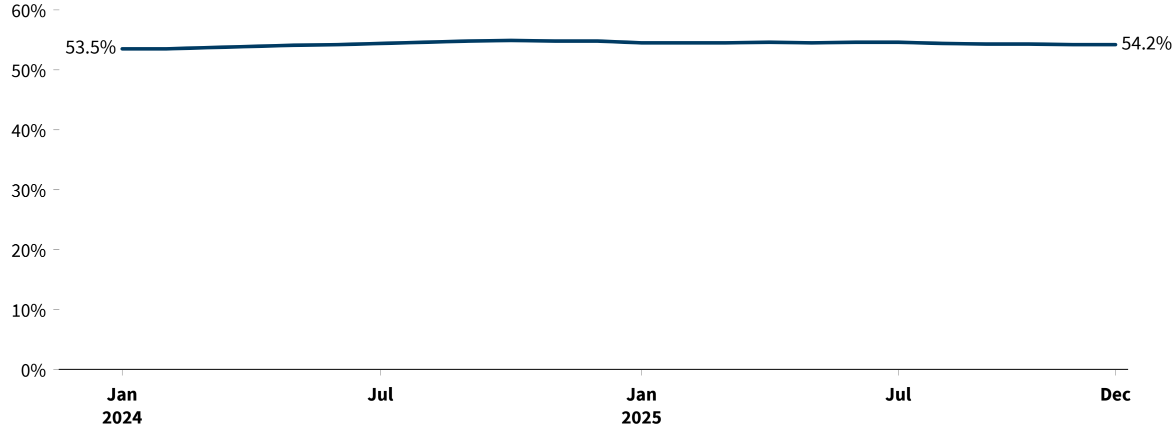
Total # of units shipped (millions of units), trailing 12 months



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Relative Share of Residential Electric Water Heaters

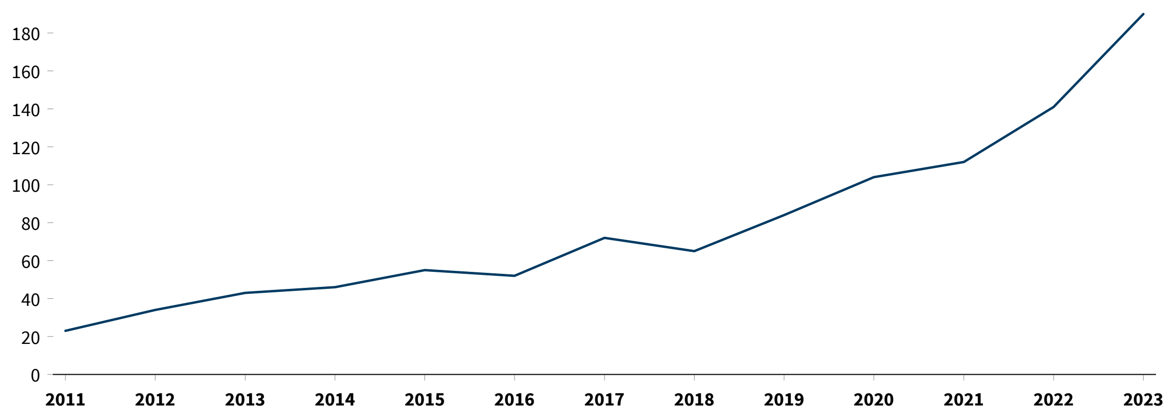
% of leading water heating shipments that are electric, trailing 12 months



Source: Air Conditioning, Heating, & Refrigeration Institute, Monthly Shipments Report • Get the data • Download image

Annual Shipments of Energy Star Heat Pump Water Heaters

Annual # of units shipped (thousands of units), 2011-2023



Source: Energy Star

Notes

- The term "sales" in these charts refer to shipments of equipment by manufacturers, which may not perfectly match product sales and installations in a given time period.
- Heat pump sales numbers are based on outdoor condensing units sold. Systems with multiple indoor heads but one outdoor condenser are counted as one unit.
- One-way air conditioning shipments count central units only (for example, they exclude window A/C units).
- Not all HVAC sales become a primary heating system: some homes use multiple heat pumps and/or multiple furnaces. EIA RECS data from 2015-202 suggests that 35% of heat pump sales replace an existing system, 30% become a new primary heating system, and 35% become a secondary heating system.
- Market share refers to the share of equipment in terms of annual shipments.
- The water heater market trends compare electric to gas water heaters, as data on heat pump water heaters is unavailable on a quarterly basis.
- These graphics are based on AHRI shipment data, which may not capture commercial space heating systems. We did not include less common fuel types including electric resistance, propane, wood, and gas boiler systems.

Year End	GCR/GCC	Aggregate	Total
2003	1,249,108	388	1,249,496
2004	1,257,401	402	1,257,803
2005	1,269,112	455	1,269,567
2006	1,257,532	611	1,258,143
2007	1,251,203	646	1,251,849
2008	1,236,389	644	1,237,033
2009	1,223,030	687	1,223,717
2010	1,217,119	769	1,217,888
2011	1,215,979	810	1,216,789
2012	1,221,051	786	1,221,837
2013	1,226,607	827	1,227,434
2014	1,231,700	837	1,232,537
2015	1,241,027	797	1,241,824
2016	1,251,524	801	1,252,325
2017	1,260,897	725	1,261,622
2018	1,272,081	708	1,272,789
2019	1,284,315	682	1,284,997
2020	1,301,140	689	1,301,829
2021	1,312,496	681	1,313,177
2022	1,323,954	625	1,324,579
2023	1,331,932	615	1,332,547
2024	1,342,761	617	1,343,378
2025	1,351,543	583	1,352,126

Three Decades of Scenario Planning in Shell

Peter Cornelius
Alexander Van de Putte
Mattia Romani

Investment risks and opportunities have to be assessed in full recognition of the external environment in which corporate strategies are elaborated. Environmental uncertainty is not easily encapsulated as a simple risk parameter, but rather interacts with corporate strategy in global, national, and industrial contexts.[1] An important risk companies face is that major shifts in the business environment (e.g., due to changes in the geopolitical landscape, government policies, and industry structure) can make whole investment strategies obsolete. These changes can occur very abruptly as the result of a single event. The terrorist attacks on September 11, 2001, for example, have fundamentally altered U.S. foreign policy, upending nearly all the basic assumptions about political, economic, and financial risks.[2] Given the irreversibility of most major capital investments, however, their sunk costs may be huge.

Changes in the business environment can also create important new opportunities. The end of the Cold War, the collapse of the former Soviet Union, and Russia's opening have allowed companies to invest in one of the world's most resource-rich countries. China's race to the market has produced spectacular economic growth and become a key driver for the world's commodity markets. New opportunities have arisen for renewable energy, thanks mostly to more stringent environmental regulations.

Unfortunately, forecasts—which are usually constructed on the assumption that tomorrow's world will be much like today's—provide an inappropriate tool to anticipate shifts in the business environment. In fact, forecasts may even

The authors would like to thank Albert Bressand, Tom Copeland, Ged Davis, Bruce Kogut, Adrian Loader, Thierry Malleret, and two anonymous referees for their comments. The views expressed in this article are those of the authors and do not necessarily reflect the views of the Royal Dutch/Shell Group of Companies nor those of the World Economic Forum.

be dangerous, as they are typically wrong when they are needed most.[3] There are numerous examples of individual strategic busts in virtually every industry.[4] Discontinuities in the business environment present the greatest challenge in the energy sector, given the average size of investment projects and their long lead times. To deal with this problem, the Royal Dutch/Shell Group uses scenario analysis, a method it introduced more than 30 years ago.[5] Since then, global scenarios have been developed every three years, with the latest set presented at the World Economic Forum in Davos in January 2005.

Scenarios are not projections, predictions, or preferences; rather, they are coherent and credible alternative stories about the future. They are designed to help companies challenge their assumptions, develop their strategies, and test their plans.[6] At Shell, scenarios have played a particularly important role in anticipating shifts in the global energy mix and hence in determining the Group's upstream and downstream investments. Combined with other tools such as market and competitive analyses, scenarios represent an integral part of the Group's strategy process at all decision levels.

Peter Cornelius is the Group Chief Economist of Royal Dutch Shell and a professor at Vlerick Leuven Gent Management School. <peter.cornelius@shell.com>

Mattia Romani is an economist with Royal Dutch Shell. <mattia.romani@shell.com>

Alexander Van de Putte is Director, Business Insight, of the World Economic Forum and a professor at Delft University of Technology. <apu@weforum.org>

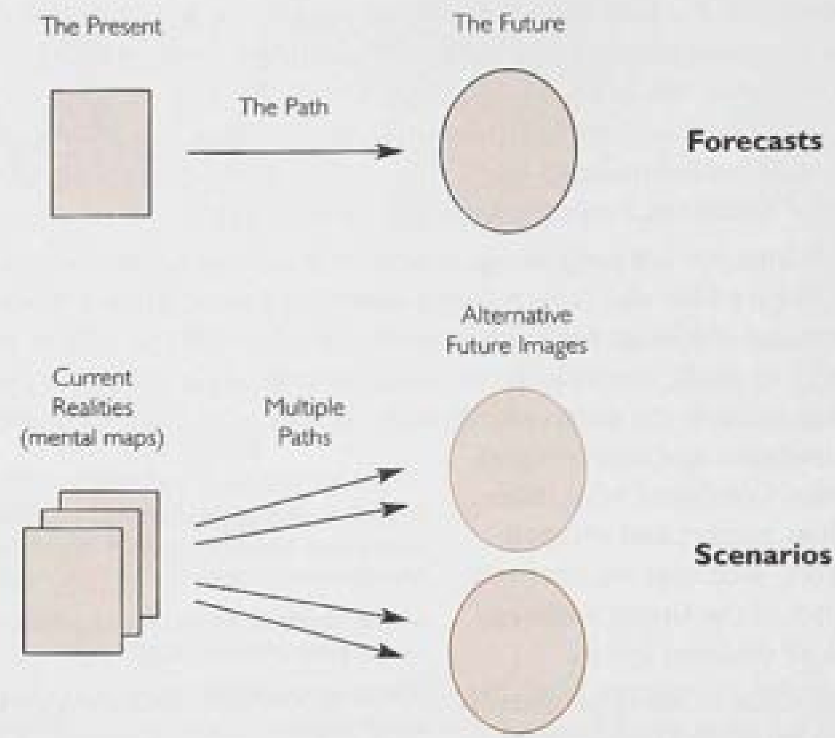
The value of many projects is contingent on earlier investments. Thus, once a company has decided to invest, it relinquishes the possibility of new information that might affect the desirability or timing of the expenditure.[7] Given the irreversible character of most investments, scenario planning can usefully be combined with real options analysis, an approach that emphasizes that many investments create important follow-on opportunities for a company. This approach is an extension of financial option pricing models to the valuation of options on real assets, and it is a way of thinking that helps managers formulate their strategic options.[8]

The real options approach is subject to important limitations. However, scenario planning may help overcome some of these limitations and assist managers in deciding when and how to exercise an option, capturing upside potential due to greater flexibility. Specifically, scenarios can contribute to real options at three fundamental levels. First, they can help identify options in the future. Second, they can help time the decision to exercise the real option. Third, they can provide an important input in the process of evaluating it.

Scanning the Future with Scenarios

The choices firms make depend on their assumptions about what the future may bring. While they know that anticipating and shaping the future is critically important for their success, there is increasing uncertainty in the medium- to long-term horizon.[9] Significant efforts have been made to improve forecasting techniques. Econometric methods have become increasingly

EXHIBIT 1. Scenarios vs. Forecasts



sophisticated, new tools such as neural networks have been developed, and powerful computers and software make it possible to work with huge amounts of data. Despite the progress in all these areas, firm success has been limited, especially over longer forecast horizons.

While forecasts can be reasonably accurate, there is a fundamental problem. Pierre Wack, one of the founders of Shell scenario planning, observed almost 20 years ago that forecasts tend to be wrong when they are needed most—namely, "in anticipating major shifts in the business environment that make whole strategies obsolete."[10] Forecasts are usually constructed on the assumption that tomorrow's world will be much like today's. As long as this is the case and there are no critical discontinuities, forecasts perform reasonably well. However, sooner or later the world does change in a major way, which render forecasts wrong when it hurts most.

Rather than looking for better forecast techniques or hiring more or better forecasters, Shell developed *scenario planning*. With its roots usually attributed to the pioneering work by Kahn and Wiener at the Hudson Institute,[11] several generations of Shell scenarios planners have refined this approach over the past 30 years.[12]

Scenario planning differs fundamentally from forecasting in that it accepts uncertainty, tries to understand it, and makes it part of the reasoning. Scenarios help prepare for a range of alternative and different futures. Scenarios are not projections, predictions, or preferences. Rather, they are coherent and credible stories, describing different paths that lead to alternative futures (Exhibit 1). As such, they should not be confused with alternative forecasts under different assumptions (for example, the price of oil may be USD 20 or 40 per barrel in 2010—sometimes called "first-generation" scenarios).

Whereas forecasting techniques try to abandon any uncertainty by providing managers with only one forecast, multiple scenario analysis deliberately confronts decision makers with environmental uncertainties by presenting them with several, fundamentally different outlooks on the future.[13] Scenarios are generally built upon a dynamic sequence of interacting events, conditions, and changes that are necessary to reach a particular outcome. Thus, scenarios focus attention on causal processes and crucial decision points.

Scenarios serve multiple functions. First of all, they present a background for the design and selection of strategies. Since no single strategy can perform best in each scenario, special selection criteria, such as "bet on the most probable scenario" or "preserve flexibility" are needed.[14] Second, scenarios help make managers aware of environmental uncertainties by confronting them with fundamentally different future states. Third, scenarios provide a tool to identify what might possibly happen and how an organization can act upon or react to future developments. As such, scenarios can serve as early warning systems. Fourth, scenarios offer the possibility to combine quantitative data with qualitative input, enabling scenario planners to incorporate results from other forecasting techniques and allow for soft and fuzzy variables. Finally, scenarios can help stretch managers' mental models by explicitly confronting them with their own biased viewpoints.

A Brief History of the Shell Scenarios

Although the scenarios at Shell have been made public only recently,[15] earlier scenarios are well documented in the literature, especially through contributions by former Shell scenario planners.[16] The first scenarios were developed in 1972, although a special "Survey of Energy in the World Political and Economic Environment for the Years 1985-2000" and some experimental scenarios had already been prepared in 1967 and 1971. The six scenarios produced in 1972 concentrated on economic growth, oil supply, and oil price options. While they included some description of the geo-political context, the scenarios' main focus was on the key variables of direct impact for the businesses. In a world characterized up until then by continuing and sustained expansion, the scenarios foresaw a disruption in oil supply and the subsequent rise in prices. By October 1974 this scenario had quickly materialized, with the Arab Oil Embargo following the Yom Kippur War pushing oil prices to unthinkable levels. The advent of the first oil price shock did much to cement the scenario tool in the planning process in the Group.

Later in the 1970s, in an attempt to make scenarios more suited to address medium-term concerns and assist tactical decision making, scenarios were produced both for medium- and for long-term purposes. In 1974, "the

Rapids" emerged as a framework onto which to build specific scenarios: it described a period of transition and new challenges in the wake of the oil crisis. Clearly what was needed at that specific time was a map to orientate the business in a very different and uncertain environment: *Belle Époque* and *World of Internal Contradictions (WIC)* were the first comprehensive scenarios—where the long-term economic and energy markets predictions were accompanied by an equally important geo-political and social analysis.

Constrained Growth was developed in 1975 as part of *WIC*, and was centered on the idea that recovery would be slower than in previous upswings. *WIC* described a world of low economic growth in stark contrast with the "miraculous" economic growth of the previous 25 years. This again was a voice out of the crowds, during a period in which quick and powerful recovery was expected. The 1976-1978 period was indeed a period of internal contradictions, with what had been the floor for economic growth expectations before 1973 now having become the ceiling. Many Shell managers recognized the structural change and adapted their business decisions, hedging the possible risk.

The late part of the 1970s saw an extension regarding the scope of the scenarios—in particular, in terms of analyzing societal change. Nevertheless, the scenarios maintained a focus on the key variables relevant to the business: energy demand and oil prices. The recession of the end of the decade made it difficult for the scenarios to attract managers' attention away from the troubled short-term conditions.

In the 1980s, the Shell scenarios elaborated the socio-political analysis further. High oil prices and a looming recession inherited from the late 1970s, represented the background for a series of rather pessimistic scenarios. First in 1982 and subsequently in 1984, the scenarios included the possibility of a sharp drop in oil prices in the medium-term: *Next Wave* suggested that by 1986/1987 the price for oil could drop to USD18/bbl. A key driver was seen in the tightening of the credit markets and the growing burden of the U.S. fiscal deficit.

The 1982 scenarios speculated about the longevity of the former Soviet Union. This was the result of a specific scenario for centrally planned economies, a first attempt at focused scenarios, which would become the norm by 1988. *Devolution* suggested a gradual opening-up of Central and Eastern Europe due to the need for technology and for consumer goods.

By 1987, the Shell scenarios had grown in size, comprising three separate volumes on oil, energy, and socio-economic trends. For the first time, the scenarios identified the possible tensions arising from globalization as a fundamental trend for the 1990s. Moreover, in these scenarios environmental issues gained increasing importance. It was only in 1989, however, that these two areas represented the gravity center of analysis. Specifically, the *Sustainable World* scenario contemplated the write-down of developing countries' debt and the signing of stringent environmental treaties.

In the book *The Roaring Nineties*,[17] the dismantling of economic borders, the liberalization of markets, and the relentless onrush of new technology became such powerful trends that they were widely perceived as something to which "There Is No Alternative" (TINA). With these trends believed to continue to be the primary shapers of the future, the 1995 scenarios were built on *New Frontiers*, one of the 1992 scenarios, with the question being not "will the world embrace or resist TINA?" but rather "What form of embrace will be most successful"? With governments seen as neither quick enough nor competent enough to match the dynamic power of corporations, the world of *Just Do It!* stressed individualism and libertarianism. This scenario was contrasted with one—*Da Wo*—which was based on a more communitarian approach, emphasizing cohesion and the idea that "governments do matter."

As technological progress, market liberalization, and globalization continued unabatedly, and indeed gathered further steam in the second half of the 1990s, "the 1998 scenarios were built on *Just Do It!* as the only successful kind of response to TINA." *The New Game*, a "TINA above" scenario, represented a world where global governance was promoted through the development of new institutions to enhance the health of the global economy. *People Power*, a "TINA below" scenario, explored the effects of growing numbers of people becoming wealthier and better educated than ever before.

Shortly after *The New Game* and *People Power* were published, the world was shaken by the events in Seattle, which led to a breakdown in the WTO trade negotiations. These violent demonstrations against globalization represented a major branching point, which was difficult to reconcile with TINA as expressed in the 1998 scenarios. It was against this background that the 2001 scenario, *People and Connections*, asked whether TINA was overturned. The answer given was a no, albeit a qualified one. The forces of globalization, liberalization, and technology were anticipated to continue. However, it was recognized that people want not only the efficiencies that market liberalization brings, but also government regulations to assure uninterrupted supply of essential goods, including energy.

These issues were explored in two scenarios, *Business Class* and *Prism*. Specifically, the scenarios emphasized that globalization was not just expanding economic opportunities, but was also pushing the boundaries of culture and family. They also stressed the enormous ethical dilemmas technology may bring about. In *Business Class*, the world was seen as one that was not run by business, but like a business with a focus on efficiency and individual freedom of choice. *Prism*, by contrast, was depicted as a world that had gone beyond the modernist emphasis on efficiency, functionality, and global homogeneity toward the realization of "multiple modernities" that incorporate diverse cultural values and practices.

Motivated by the dual crises of international security and trust in the market—which were triggered by the terrorist attacks of September 11th and the corporate governance debacles of Enron, WorldCom, and others—the most recent scenarios presented in early 2005 focus on the interplay of market incentives, aspirations to social cohesion, and the provision of security and oversight by the state. While these scenarios are built on past global scenarios, notably *People and Connections*, they emphasize to a considerably larger extent the interaction between these forces and the trade-offs between objectives that they can plausibly foster. While societies often aspire to all three objectives—efficiency, equity, and security—the scenarios make clear that these objectives display elements of mutual exclusiveness: One cannot be at the same time freer, more conforming to one's group or faith, and more coerced.

Against this background, Shell's latest scenarios consider three different worlds. In *Low Trust Globalization*, the leading theme is "carrots and sticks." Governments use market incentives to promote economic efficiency within a stringent regulatory and security framework. However, institutional discontinuities persist, with rapid regulatory change, overlapping jurisdictions, and conflicting laws leading to intrusive checks and controls—which impede economic integration and hinder the movement of goods, people, and knowledge. Compliance and superior risk management are key challenges in this scenario.

Driven by economic efficiency and the aspiration to social cohesion, *Open Doors* represents a world in which a trans-national society develops around market incentives. Compliance certification, regulatory harmonization, voluntary best-practice codes, and close links between investors and civil society encourage cross-border integration, international cooperation, and virtual value chains. Globalization continues unabated, and rapid technological progress and diffusion of knowledge supports strong productivity growth. In this world, networking skills and superior management are essential.

Flags, finally, is a world of nations and causes. Unlike in *Open Doors*, however, causes are pursued defensively, and as trust remains fragmented, the state resorts to the flag in an attempt to rally groups fighting under various political, social, and religious banners. Thus, the backlash against globalization is the result not so much of anti-globalization sentiment as of the absorbing nature of divisive domestic politics. Efficiency takes a back seat to security and solidarity. Governments resort to populist policies, with differing rules and standards, and to protectionist measures that inhibit the flows of trade and capital. Gated communities, patronage, and national standards exacerbate fragmentation and call for careful country-risk management.

Scenarios as an Integral Part of Strategic Planning

Shell's track record in anticipating major structural changes in the global energy markets has substantially enhanced the credibility of scenario analysis within the Group. The most legendary example is probably the first oil price shock that was anticipated in Shell's first global scenario. Other examples include the impact of higher oil prices on economic growth in the 1970s, the substantial decline in oil prices in the mid-1980s, European integration, and the collapse of the former Soviet Union. Of course, not everything was detected by the scenario team's radar screen, and some important developments have been underestimated in terms of their importance for the Group. Recent examples includes China's rise as a global economic powerhouse, the backlash against

EXHIBIT 2. Capitalising on Uncertainties: Scenarios at Shell

1970s Methodology Development

THE RAPIDS

- Pioneering of scenarios to prepare the organization for uncertainty and change
- Focus on energy markets (oil)
- Internal publication only

1980s Integration into Corporate Strategy

TRANSITION

- Broadly based global scenarios
- Energy focus is combined with political and economic analysis
- Internal publication only
- Workshop with business units

1990s Focus on External Stakeholders

TINA: THERE IS NO ALTERNATIVE

- Scenarios involve external stakeholders & incorporate their views
- Deeper analysis of social trends and environment change
- Internal and external publication
- Workshop with business units & externals

2000s Integration into Business Strategy

PEOPLE & CONNECTIONS

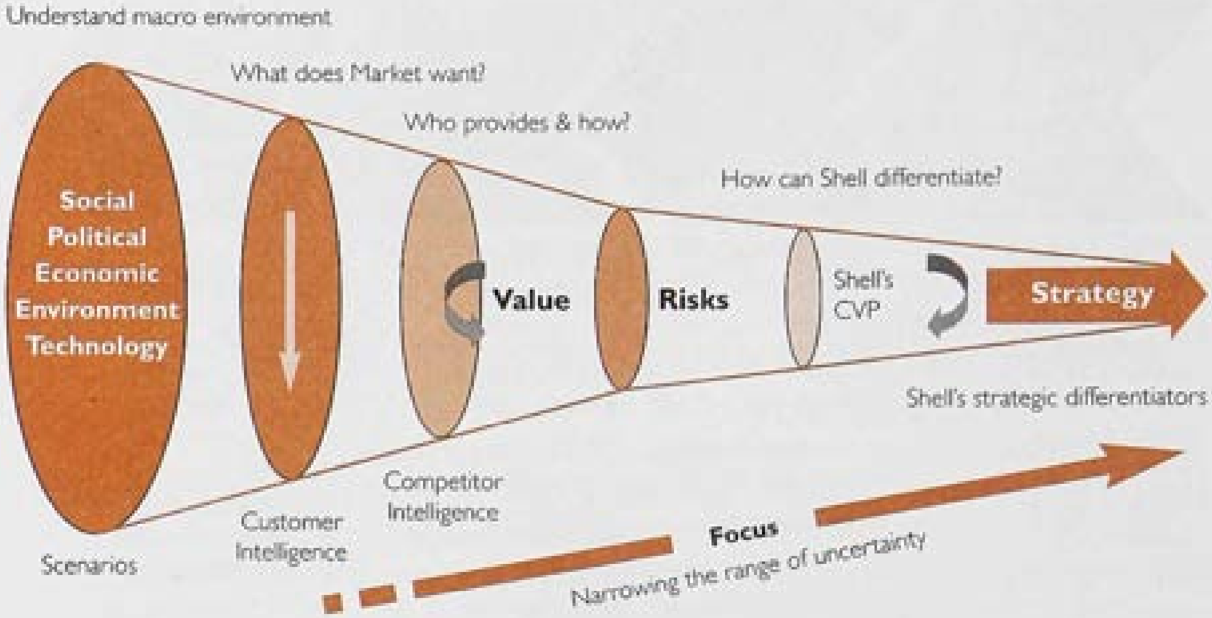
- Global scenarios are used to develop focused scenarios on specific business initiatives
- Scenarios are used systematically to test business strategy robustness
- Internal and external publication

globalization, and the new scale of global terrorism. However, it appears doubtful whether traditional forecasting techniques would have performed better.

Arguably, however, the accuracy of the scenarios with regard to the prediction of events and the assessment of economic, energy, and price trends is only of secondary importance. What matters most is the ability to identify the driving forces, explain how these work, and ensure that the client understands them. Only then can scenarios be expected to influence and help improve strategic planning.

Reflecting this fundamental insight, scenario planning in Shell has been subject to important changes over the last three decades, not just in terms of the focus of the global scenarios, but also with regard to the underlying approach and how scenarios are incorporated into the strategic planning process (Exhibit 2).[18] The global scenarios remain at the center of this process, providing a comprehensive assessment of how the future business environment could develop. They are combined with a range of applications that provide a broad framework of ideas influencing strategy at the corporate level and assisting the businesses in identifying risks and opportunities. With the global scenarios setting the macroeconomic framework, the strategic funnel is then narrowed further by analyzing demand trends in individual energy markets and the strategic behavior of Shell's competitors. This analysis is followed by a comprehensive risk analysis. At this stage, the degree of uncertainty is sufficiently reduced to define the Group's customer value proposition and its strategic differentiators, which then leads

EXHIBIT 3. Using Scenarios in Strategic Planning

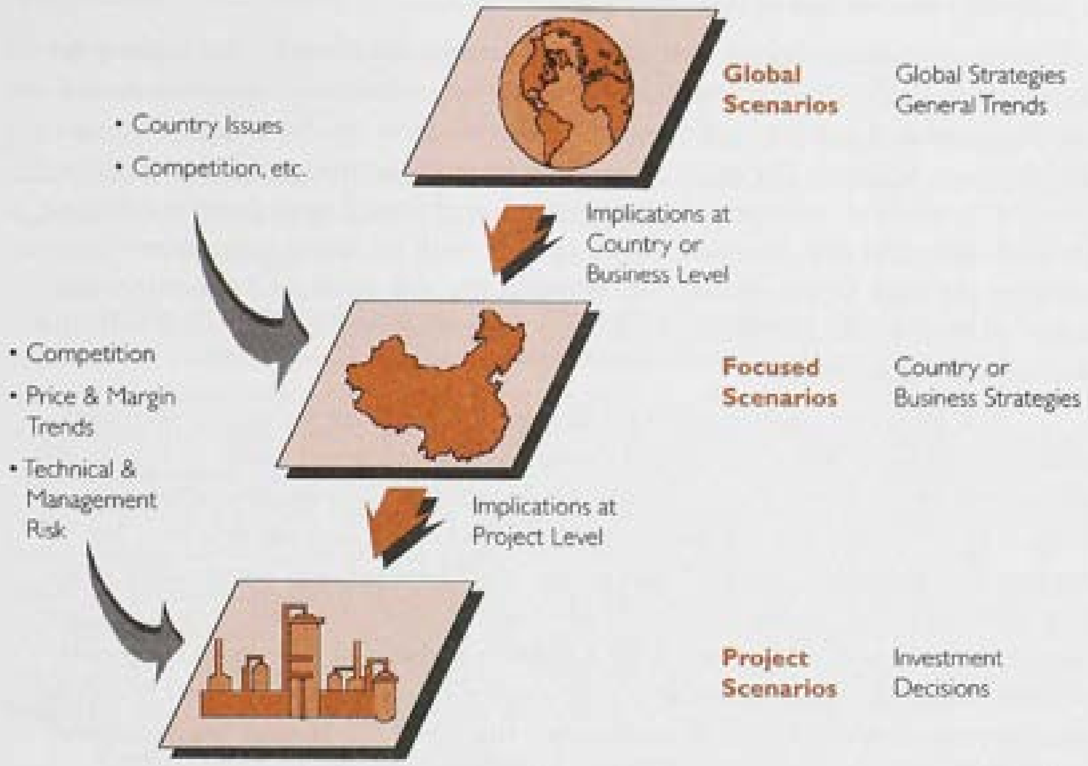


to strategic decisions about the aspired upstream and downstream portfolios (Exhibit 3).

The global scenarios have helped the Group gain competitive advantage in the past and continue to drive Shell's upstream and downstream portfolio decisions.[19] In its Group Strategy Review in late 2004,[20] the Executive Committee outlined several key decisions regarding Shell "aspired" portfolio that are based on scenario planning. Against the background of a higher price outlook, these decisions include more capital spending on exploration and production of oil and gas; a rising share of natural gas, with integrated gas reaching 40-45% of total production by 2014; and a rising share of unconventional oil especially from Canadian oil sands. On the downstream side, capital deployment is envisaged to shift to new growth markets, with Asia's share in oil products forecast to rise by around 15 percentage points to around 40% by 2010.

While the global scenarios are designed to help the company formulate its overall tactical and strategic policies and permit management to explore new ideas by shifting the company away from "group-think," over time focused scenarios have gained in importance. Typically, these scenarios deal with country-specific issues or individual projects (Exhibit 4). While the different levels of analysis are closely intertwined, the process that links them is flexible. As Shell's experience suggests, a mechanistic planning process that forces managers to produce a strategic response to global scenarios at the same point in time does not necessarily produce uniformly high-quality responses from the business units. Indeed, it appears that business units invest more energy and creativity in strategy development only occasionally when there is a formal planning process.

EXHIBIT 4. Bringing Scenarios to the Business



Focused scenarios tend to be more closely aligned to improving the judgment of individual managers on specific investment decisions. At the project level, it must be demonstrated that a particular investment is sufficiently robust against both the global scenarios and the supporting focused scenario. For instance, could abrupt changes in the regulatory framework make a project obsolete? To what extent could changes in the geopolitical landscape affect production and transportation? To what extent could demand shifts affect the economics of a project?

Selecting Projects Using Real Options

The belief in a single outcome can lock us into a narrow set of options, a risk that scenarios can help to mitigate by discovering the full range of pathways. Suppose we know that scenario A is going to happen. All the uncertainty is gone and we can actively think about options. If we know, for example, like Noah, that it will rain for forty days and forty nights, we would need to creatively generate options for a flood scenario. In this "take-a-phone-call-from-God" example, we might just come up with the idea of building an ark,[21] an option we might never have conceived if we had seen the flood only as a very remote possibility. By going through all the scenarios and turning them into 100 percent certainties, we can identify options that we may overlook if we limit ourselves to predict probable futures. Thus, scenarios can help us determine the universe of possible options. The question remains, however, as to how we should select a particular project out of this universe.

Firms should allocate investment resources according to the highest *net present value* (NPV). NPV is the future discounted cash flow of the project and can be calculated using a variety of intrinsic valuation methods depending on the situation at hand. The most commonly known method is the *discounted cash flow* (DCF) method, whereby the present value of future cash flows is adjusted for both time and risk. The time factor is dealt with by using appropriate interest rates for the time frame considered, whereas the risk adjustment requires estimates of both expected values of the cash flows and their correlations with the overall market portfolio.

The DCF approach appears particularly suitable for valuation purposes when uncertainty about the critical drivers of the valuation (such as prices, volumes, and costs) is low. However, this assumption is increasingly being challenged. In an earlier era, the business world had much less uncertainty. As Amram and Kulatilaka argue,[22] given that most product and commodity markets were relatively stable and predictable and globalization was much less pronounced, there was seldom need for a sudden and major change in corporate strategy. Analysts had a reasonably high degree of confidence in their forecasts, and they could operate with the assurance that once the project was accepted, the firm would attempt to run it pretty much according to plan.

This is where real options analysis comes in. Representing the right—but not the obligation—to invest, real options are a tool that may have important advantages where uncertainty is high. Their roots lie in the financial option pricing models developed by Black and Scholes and by Merton in the early 1970s.[23] As an extension of such models to the valuation of options on real (i.e., nonfinancial) assets,[24] the real options approach is a way of thinking that helps managers formulate their strategic options, i.e., the future opportunities that are created by today's investments. The real options approach focuses on the potential value embedded in exercising the option once the uncertainty has been resolved—that is, it values strategic initiatives by recognizing all the downstream choices that may be encountered over an investment's life.[25]

Real options and DCF analysis are not necessarily mutually exclusive. In fact, as van Putten and MacMillan show, real options may actually enhance DCF analysis. Where future cash flows are subject to substantial uncertainty, DCF analysis requires them to be discounted at a high rate. While the possibility that actual cash flows may be lower than forecast is captured in the valuation, the possibility that they may be higher is not. Therefore, there is an inherent bias in the DCF approach in the sense that managers may be led to reject highly promising, if uncertain projects. This is exactly where real options come in: They provide a way to recapture some of the value lost through the conservative DCF valuation while still protecting against the considerable risk of pursuing highly uncertain projects: "The DCF valuation captures a base estimate of value; the option value valuation adds in the impact of positive potential uncertainty."[26]

EXHIBIT 5. DCF versus Real Options*

DCF—Traditional	Real Options
Operating decisions will not change in the future	Directional changes pending arrival of new information
Base case set of expected cash flows	Cash flows contingent on future uncertain conditions
Static sensitivity analysis	Managerial flexibility to react to changing conditions

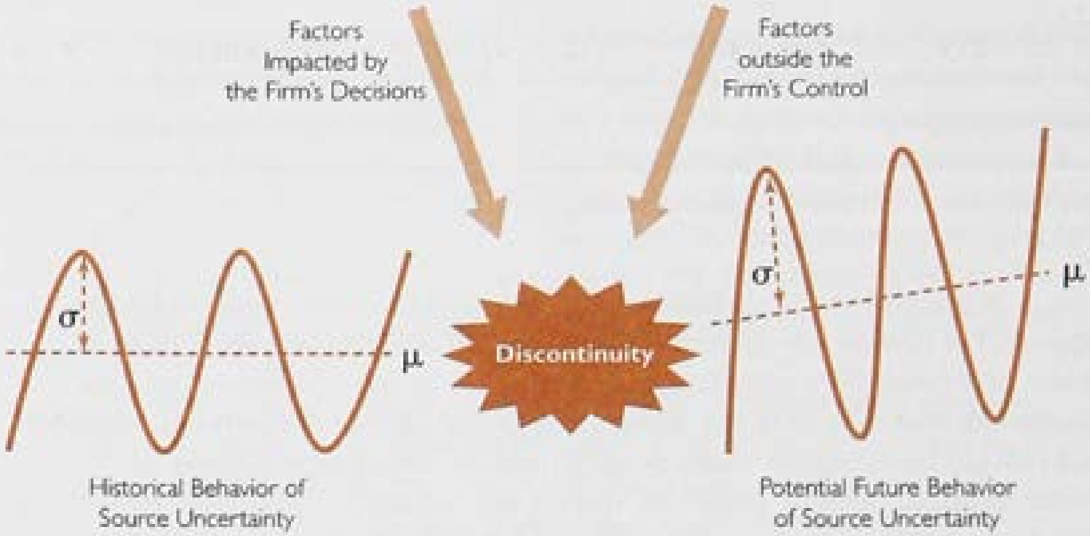
*See Marion A. Brach, Real Options in Practice (Hoboken, NJ: John Wiley, 2003), p. 331.

While real options analysis may offer some intriguing benefits for the appraisal of investment decisions and significant advantages compared to a static DCF-based NPV appraisal process (Exhibit 5), there are also important challenges that may limit the applicability of real options. Importantly, standard approaches based on the Black-Scholes formula, which are routinely used to value financial options, cannot be applied as a number of conditions are violated. Moreover—although this applies to the DCF approach as well—the assumption must be made that there is a traded security or a portfolio of securities whose risks and payoffs mimic the expected risks and payoffs of the investment project to model future returns. However, the farther we move away from financial markets, the more difficult and costly it is to track an option.

Furthermore, while the purchase and exercise of financial options is unlikely to alter the payoff dynamics of the replicating portfolio consisting of financial assets (stocks and bonds), the same might not be true for real options. Steps taken or not taken by any individual firm may have an immediate impact on the action of its competitors and hence the market equilibrium. An oil company, for example, that relies on the volatility of oil stocks, futures, or oil prices to replicate its real option on exploring a new oil field becomes immediately part of the dynamics that govern the twin security when acquiring the option. Its decision to explore the oil field will already send a signal to its competitors and alter their investment decisions.

While these challenges in applying real options to oil energy investments are important but not insurmountable, the most important problem lies in the limited guidance that history can provide for the future. Specifically, the search for twin securities whose past stock volatilities could serve as a proxy for the future volatility of a corporate investment project appears of limited value in rapidly changing environments. To be sure, there have been several paradigm shifts over the last three decades—most importantly, the two oil prices shocks in the early and late 1970s, the subsequent collapse of oil prices in 1986, and the recent increase in prices since 1999. If stochastic processes assumed in financial option pricing to estimate future values of the underlying asset do not seem appropriate for real options, what are our alternatives to quantify the uncertain value drivers of the project (the source uncertainties), notably the forward-looking mean annual volatility and the mean reverting coefficients?

EXHIBIT 6. History as a Predictor of the Future



Starting from an analysis of historical price and quantity data, it is important to understand the factors that may affect them. These factors explain why future payoffs may differ from past payoffs (Exhibit 6):

- Factors affected by the firm's decisions are usually project- or sector-related and are generally easy to identify. Technological breakthroughs are examples of factors influencing the volatility of source uncertainties. These factors are typically not correlated with the general movements of the economy and require deep sector knowledge to identify them and assess their potential impact.
- Other factors may be outside the firm's control, however. Often, they depend on the social, economic, and political environment and may affect an entire sector or region and even the global economy. Deregulation of the telecommunication sector in Europe during the 1990s is a factor outside the firm's control that turned the telecommunication sector upside down, as most incumbent players were not ready to effectively compete in a deregulated market. Not surprisingly, deregulation of markets usually leads to an increase in uncertainty. Conversely, regulation leads to a decrease in uncertainty as the future becomes more predictable and stable.

In analyzing the potential future behavior of source uncertainty on the basis of factors that are within and outside the firm's control, scenario planning may provide a useful tool. As Brach argued, "for real option analysis scenario planning approximates what volatility is for financial option pricing. It builds on existing knowledge and past experience to create a range of plausible scenarios for the future, just as financial options rely on past volatilities when predicting

EXHIBIT 7. The Five Phases of Oil and Gas Exploration

future volatilities."[27] In this context, scenarios can provide key information that helps evaluate the option and time the decision to exercise it.

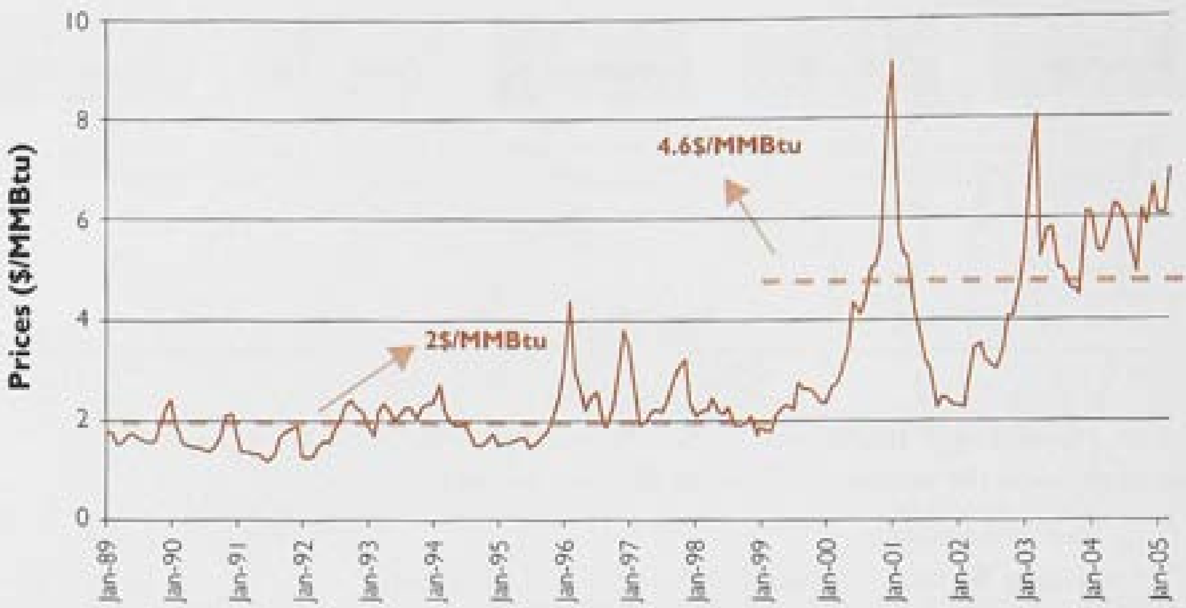
Combining Scenario Analysis and Real Options: An Illustrative Example

Taking into account that a project's value may change over time due to the introduction of new information and the ability to act on that information, real options analysis is especially suitable for staged investment decisions in highly uncertain environments.[28] Exhibit 7 shows the stages of an oil or gas field investment from exploration to extraction, a sequence that might cover several decades. Each box indicates a stage of activity, and a decision whether to continue or not is made at the beginning of each stage. Each stage can be seen as a call option on the value of continuing with the exploration, a value that includes the value of all future options. As Amram and Kulatilaka argue,[29] exploration decisions are strongly affected by market-priced risk and exploration options can be valued with reasonable accuracy by tracking portfolios composed of oil/gas securities.

For example, consider an oil and gas company in the mid-1990s that had just discovered significant amounts of natural gas in West Africa. Bringing this natural gas to the market requires either piping or liquefying and then shipping it overseas to Europe and North America. However, shipping natural gas adds significant costs associated with liquefaction, storage, transportation, and regasification.

In the 1990s, the natural gas market in the United States was very much business as usual with few changes. With the gas market having become largely decontrolled in the 1980s,[30] few expected new discontinuities going forward. Thus, the mean gas price between 1991 and 1999 was $2.0/MMBtu, with an annual volatility of 57.2 percent (Exhibit 8). Under these conditions, an energy company would not have considered developing the overseas field in West Africa to supply North America, since the high costs associated with liquefaction, transportation, and regasification would have yielded a negative NPV.

EXHIBIT 8. Historical Henry Hub Prices



Source: Bloomberg Professional.

However, natural gas prices in the United States more than doubled in the first few years of this decade. Specifically, between January 2000 and January 2005 the Henry Hub price (the benchmark price for the U.S. gas market) averaged $ 4.6/MMBtu. At the same time, price volatility increased substantially, to more than 100 percent. Several demand and supply factors have caused this fundamental shift in what is the world's largest integrated gas market. On the demand side, concerns about air pollution have become increasingly important, and with people becoming more health conscious, natural gas is increasingly favored for domestic heating.[31] It is estimated that 75 percent of all homes built in the last fifteen years use natural gas, bringing the current level of all U.S. homes to 50 percent. At the same time, environmental regulations have been tightened, favoring natural gas to fire power plants.

Greater demand for cleaner energies and more stringent environmental regulations has fostered technological progress. Combined Cycle Gas Turbine (CCGT) technology is both simple and efficient (a premium of around 50 percent compared with coal). In addition, output can more easily be matched to demand, resulting in less wastage of energy. Over the last decade, this resulted in massive investments in CCGT plants for electricity generation, dramatically increasing the demand for natural gas.

The impact of higher demand for natural gas has been compounded by supply-side factors. According to the U.S. Department of Energy (DOE), technically recoverable natural gas reserves amount to around 36,200 tcf (trillion cubic feet), which is equivalent to around 67 years of current U.S. production. However, as the DOE points out, most of the increase in U.S. natural gas production will come from unconventional sources (tight sands, shale, and coalbed methane) whose costs are considerably higher. Moreover, restrictions on exploration and production in some areas have limited the development of resources. In fact, almost 40 percent of the gas found on U.S. federal lands is subject to production restrictions. Furthermore, no acreage along the east and west coast is available for exploration and production. Against this background, it is expected that a large increase in LNG imports will be required to satisfy rising domestic demand.

This example emphasizes the importance of mapping causal linkages among different factors that may or may not be outside the firm's control. Focusing on the complex interplay of technological, regulatory, environmental, and supply factors, scenario planning could have helped to anticipate the emerging discontinuity in the U.S. natural gas market. Of course, scenarios, as stressed earlier, are not forecasts, and they can be used in the strategic planning process only in conjunction with specific tools to select individual projects. Traditional DCF analysis would have rejected the investment in the development of the West African gas field and the LNG chain to ship the natural gas to the United States. However, real options analysis combined with scenarios could have come to a different conclusion. Instead, scenarios would have signaled that the firm's option to develop the gas field could come to maturity. Capturing the upside of price risk, a combined real options/scenario analysis could have induced investment in the entire LNG chain between the gas field and the U.S. consumer market, with the option to expand the investment later depending on market conditions.

Conclusions

While scenario planning represent an important tool to understand the critical uncertainties and their interrelationships, this tool is not designed to choose particular investment projects and allocate capital efficiently in the best interest of shareholders. Scenarios should usefully be combined with a real options approach, as a project's value may change over time due to the introduction of new information. Scenarios can contribute to real options at three fundamental levels. First, they can help identify future options. Second, they can help time the decision to exercise an option. And finally, scenarios can provide important input in the process of evaluating real options.

Notes

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19. For instance, the scenario that anticipated the first oil price shock enabled the Group to respond quickly to the oil embargo, boosting its margins to the top of its peer group. In the years that followed Shell's advantage among the international oil companies widened further, and while in 1970 the Group had 35 percent less market capitalization than Exxon, it led Exxon with 25 percent by the end of 1994.
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22. Amram and Kulatilaka, op. cit.
23. Fischer Black and Myron Scholes, "The Pricing of Options and Corporate Liabilities," *Journal of Political Economy*, 81/3 (May/June 1973): 637-654; Robert C. Merton, "Theory of Rational Option Pricing," *Bell Journal of Economics and Management Science*," 4/1 (Spring 1973): 141-183.
24. Although the term "real options" was already coined in 1977, the new approach gathered considerable momentum only in the second half of the 1990s thanks to important contributions by Dixit and Pindyck, Trigeorgis, and Amran and Kulatilaka. See Dixit and Pindyck, op. cit.; Lenos Trigeorgis, *Real Options. Managerial Flexibility and Strategy in Resource Allocation*

(Cambridge, MA: MIT Press, 1996); Martha Amram and Nalin Kulatilaka, *Real Options: Managing Strategic Investment in an Uncertain World* (Boston, MA: Harvard Business School Press, 1999); Jeffrey J. Reuer and Michael J. Leiblein, "Real Options: Let the Buyer Beware," in James Pickford, ed., *Mastering Risk, Volume 1: Concepts* (London: Financial Times and Prentice, 2001), pp. 79-85.

25. Real options analysis may also be applied to country risk assessments. One example concerns alternative modes of market access through exports as opposed to foreign investment. For example, if the investor is uncertain as to whether the introduction of a more investment-friendly tax rate is permanent, he may attach a (subjective) probability to the potential reintroduction of the tax at the original level at a later stage, which could make his investment obsolete. Clearly, the investor will only commit his capital if the expected profits from investing now (net of investment costs) exceed the present discounted value of all future profits from exporting; he will continue to export otherwise. However, if the investment can be delayed, the investor will gain information about the eventual state of policy and take the optimal decision once all uncertainty is resolved. By committing his capital in the initial period, he kills the option and thus foregoes this opportunity. He incurs an additional cost that is equal to the value of the option to invest. See Alexander Lehmann, "Country Risks and the Investment Activity of U.S. Multinationals in Developing Countries," IMF Working Paper, Washington, D.C., International Monetary Fund, 1999.
26. Alexander B. van Putten and Ian C. MacMillan, "Making Real Options Really Work," *Harvard Business Review*, 82/12 (December 2004): 134-141.
27. Marion A. Brach, *Real Options in Practice* (Hoboken, NJ: John Wiley, 2003), p. 333.
28. Schoemaker, op. cit.
29. Amram and Kulatilaka, op. cit.
30. For details, see Franklin Tugwell, *The Energy Crisis and the American Political Economy* (Stanford, CA: Stanford University Press, 1988).
31. According to the World Energy Council, a natural gas powered power plant emits about 0.64 carbon per ton of oil equivalent (TOE), compared to 1.08 for coal-fired and 0.84 oil-fired plants.

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Question: Please provide responses to the following requests regarding climate goals and decarbonization strategy.

a. Please provide any studies, analyses, or internal documents that assess the risk that gas infrastructure investments made in 2025-2027 may become stranded or underutilized before the end of their useful lives due to: a) Climate policy; b) Customer electrification; and c) Declining gas demand.

Answer: a) As stated in Witness Decker testimony Question 35, DTE Gas is not currently aware of any proposed legislation or regulations that would materially impact its current business, including the utilization of existing assets.

b) As stated in Witness Decker testimony Question 30, DTE Gas has considered customer electrification but at this time does not foresee any impact on asset utilization given the limited number of customers expected to fully electrify

c) As stated in Witness Decker testimony Question 33, DTE Gas demand has decreased by 12% since 2005 while total customers have grown by 6.8%; this has not resulted in stranded assets or underutilization. Also stated in Witness Decker testimony Question 38, eliminating natural gas infrastructure would require every customer served by that infrastructure to find an alternative energy source. Therefore, even if gas demand declines, the expected impact on asset utilization is expected to be minimal.

Attachment: None

Line
No.

Figure 18: Comparison of DTE Gas and Gas Proxy Companies Operating Leverage

Company		2018 [1]	2019 [2]	2020 [3]	2021 [4]	2022 [5]
Atmos Energy	[A]	0.82	0.83	0.85	0.83	0.81
Chesapeake Utilities	[B]	0.73	0.75	0.76	0.76	0.76
New Jersey Resources	[C]	0.67	0.66	0.73	0.75	0.76
NiSource Inc.	[D]	0.58	0.84	0.82	0.82	0.82
Northwest Natural	[E]	0.72	0.74	0.74	0.74	0.74
ONE Gas Inc.	[F]	0.76	0.76	0.78	0.76	0.75
Spire Inc.	[G]	0.74	0.76	0.80	0.78	0.79
Southwest Gas	[H]	0.73	0.73	0.74	0.72	0.71
Sample Average	**[R]**	**0.72**	**0.76**	**0.78**	**0.77**	**0.77**
DTE Gas Company	**[W]**	**0.78**	**0.79**	**0.80**	**0.79**	**0.81**

It is clear from Figure 18 above that DTE Gas has above average operating leverage and hence above average risk from this measure.

Q69. Does DTE Gas face risk related to decarbonization policies?

A69. In the current regulatory and policy environment focused on decreasing greenhouse gas ("GHG") emissions, there is some uncertainty about the future of natural gas. Michigan, like many other states, have taken steps to reduce GHG emissions. Specifically, in 2020 Michigan set a goal, through executive order, to achieve economy-wide carbon neutrality by no later than 2050 and achieve net negative emissions thereafter. Michigan also set interim targets to reduce GHG emissions by 28% by 2025 and 52% by 2030. This Executive Order also orders that new buildings/facilities owned and operated by the state and those undergoing major renovations must be carbon neutral by 2040 and all existing buildings/facility owned and operated by the State to reduce energy use by 40%. Recently, Ann Arbor, Michigan began evaluating a plan to replace gas distribution infrastructure with lower emission technologies by renegotiating DTE Gas' franchise.[92] To the extent that decarbonization risks continue, the business risk of the gas LDC

[92] Tom DiChristopher, "Gas Ban Monitor: 1st Midwest ban passed in Illinois; Ann Arbor rethinks gas grid," *S&P Capital IQ Pro*, October 12, 2023.

industry would increase substantially. This risk is not included in my current recommendation and I currently see no reason to distinguish DTE Gas from the average of the Gas Sample.

Q70. Can you please summarize your assessment of DTE Gas' business risk relative to the sample?

A70. Compared to the proxy samples, DTE Gas is engaged in similar line of business, has comparable credit ratings and has access to alternative regulatory mechanisms. Similar to most natural gas utilities, DTE Gas is facing increasing risk from state decarbonization policies.[93] However, DTE Gas has higher operating leverage than the natural gas proxy group. Taken together, I consider DTE Gas' business risk to be above the average compared to the proxy samples' risk profile.

VII. COST OF CAPITAL RECOMMENDATION

Q71. Please summarize your conclusions regarding DTE Gas' risk and the necessary return.

A71. I find that DTE Gas to be of above average risk relative to the sample companies and therefore merits placement in the upper end of the reasonable range that I summarized in Figure 16 above. However, as DTE Gas is not requesting a return on equity above the midpoint of my estimated range, I do not quantify the magnitude by which DTE Gas' risk exceeds that of the average of the Gas Sample.

Q72. What do you recommend for DTE Gas' cost of equity in this proceeding?

A72. I find a range of about 10.0% to 10.7% with a midpoint of 10.35% to be reasonable for the gas sample. Based upon my review of DTE Gas' business risk profile relative to the proxy companies, I recommend that DTE Gas be placed near the midpoint of the reasonable range. This recommendation is based upon the reasonable ranges I obtained from the DCF, CAPM and Risk Premium models, considering the natural Gas Sample. I

[93] This risk is not considered in my current recommendation.

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Question: Has DTE analyzed the potential impacts of electrification on its business?

a. If so, please provide the analysis, assumptions, and methodologies, including the extent of electrification (e.g., full electrification, hybrid electrification).

Answer: Yes, DTE Gas has analyzed the potential impacts of electrification as explained in Witness Decker testimony Q/A 30 and would expect only about 4% of customers to choose an electric heat pump over a natural gas furnace.

Due to the small percentage of customers likely to switch, DTE Gas did not do additional analysis.

Attachment: None

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Exhibit: AA-28
Witness: Stults
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CANARY MEDIA
Clean energy journalism for a cooler tomorrow

Heat pump sales dipped in 2025. They still beat gas furnaces.

Yet again, heat pumps were the most-shipped heating appliance in the U.S. And experts say the factors behind last year's sales slide are temporary.

By **Alison F. Takemura**
13 February 2026

An electrician installs a heat pump on July 21, 2025, in Charlotte, Vermont. (Robert Nickelsberg/Getty Images)

Heat pumps outsold fossil gas-fired furnaces in the U.S. yet again last year.

That's the fourth year in a row – a testament to Americans' sustained appetite for the zero-emissions appliances crucial to weaning buildings off planet-warming fossil fuels.

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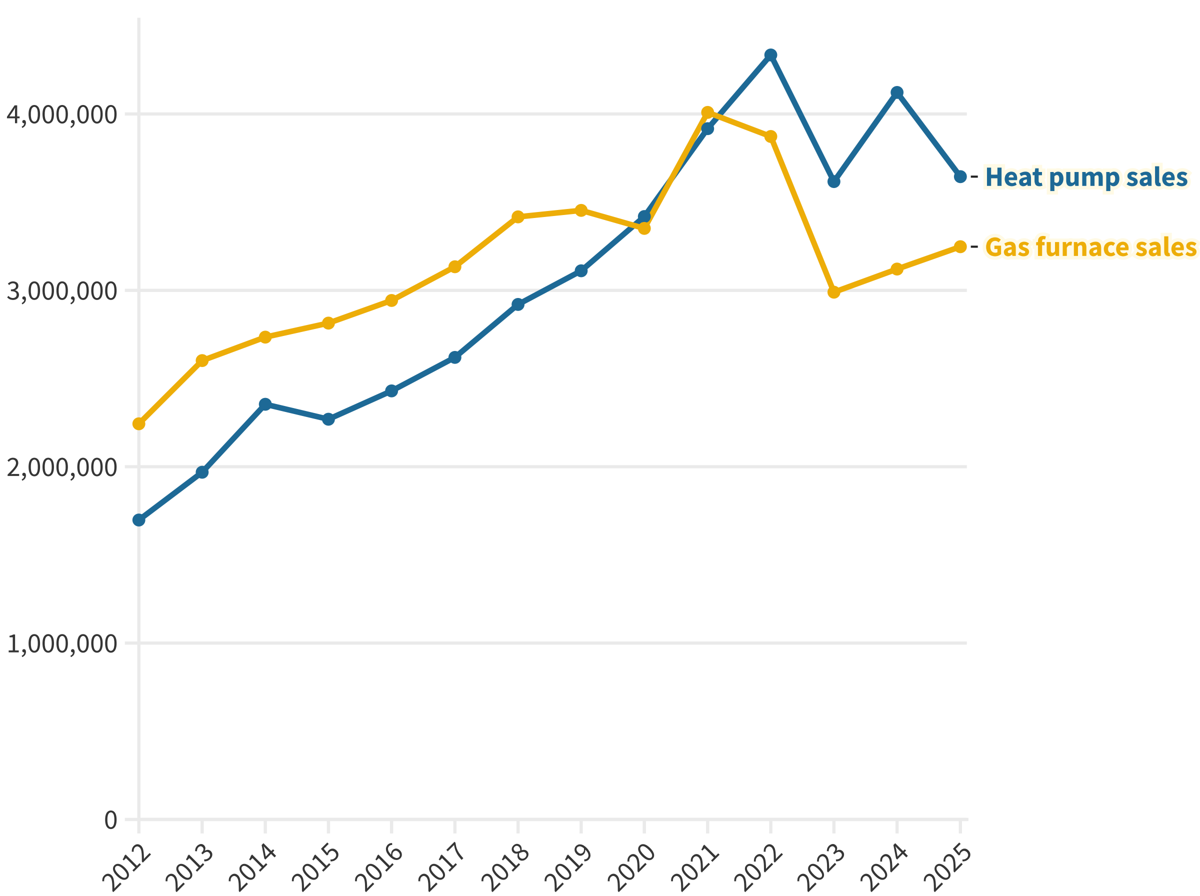

Source: Air-Conditioning, Heating, and Refrigeration Institute, Canary Media

CANARY MEDIA

Made with Flourish • Create a chart

Now, that doesn't necessarily mean that more households are installing the über-efficient appliance instead of furnaces; one home may need multiple heat pump units to replace a single furnace.

And not all the data was good news for the climate. Shipments of gas-powered units ticked upward last year to 3.2 million, while heat pump sales fell to 3.6 million.

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Electric heat pumps are two-way air conditioners that offer both space cooling and heating. They're a critical tool to eradicating carbon pollution from buildings, which account for more than one-third of U.S. greenhouse gas emissions. Because the tech is two to four times as efficient as fossil-fueled systems, heat pumps also save most households money on their energy bills – a winning attribute as more Americans grapple with a cost-of-living crisis.

So why the dip in heat pump shipments last year?

A combination of factors, from tariffs to higher interest rates to a sluggish construction market, was likely to blame, according to experts.

A changeover in refrigerants also played a role. For years, heat pumps and air conditioners utilized the hydrofluorocarbon refrigerant R-410A, which has a strong global-warming potential. But as of Jan. 1, 2025, federal law has required newly manufactured systems to use a less polluting class of refrigerants, called A2Ls.

But the refrigerant and market factors "are temporary headwinds," said Wael Kanj, research manager at electrification advocacy nonprofit Rewiring America. "I don't think they change the fundamentals. Heat pumps are still the most efficient and comfortable way to heat and cool the home."

Standing in the way of a total heat-pump takeover has long been their price tag. In 2024, Rewiring America estimated that for a medium-size home, a central heat-pump system costs a median of $25,000. A comparable gas furnace plus central AC system can cost roughly half that.

Even for the same building, contractors may provide hugely varying estimates. Last year, heat-pump research firm Laminar Collective found that for one 2,000-square-foot abode in the Boston area, installers' quotes for a whole-home heat-pump system could differ by more than $10,000.

The Trump administration has worked against making the tech more affordable. Last year, it terminated home-energy tax credits that reduced the cost of an air-source heat pump by up to $2,000, and of a ground-source, or geothermal, heat pump by an uncapped dollar amount up to 30% of the cost.

Some federal funding to boost heat pumps continues to flow, however, including a $200 million grant to Denver-area local governments. Several states – including California, Georgia, New York, and Indiana – have also been able to tap into an $8.8 billion grant program created under the Biden administration to launch home energy rebate programs that help low- and median-income households afford heat pumps.

Even without the tax credits, thousands of incentive programs that lower the upfront costs of electrification still exist at state, local, and utility levels, Kanj said. Rewiring America and the North Carolina Clean Energy Technology Center offer online tools so that households can find available credits.

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California legislators are considering a bill that would cut red tape for homeowners looking to install these electric appliances.

Investors are backing innovation in this space. The Vancouver-based startup Jetson, for example, just raised $50 million to scale its direct-to-consumer approach, which it says cuts installation costs in half.

And although U.S. heat-pump sales didn't break any annual records in 2025, the tech did quietly achieve a major milestone: In September, more heat pumps shipped than central ACs for the first time.

"It's really exciting to see the market moving in that direction," Shea said.

The Building Decarbonization Coalition's Carbonnier hopes that in the next year or two, "we'll see it fully cross over" – the way heat pumps overtook gas furnaces four years ago.

Heat pumps | Carbon-free buildings | Electrification

Michael J. Walsh, Ph.D.

Managing Partner, Groundwork Data

Arlington, MA | mjw@groundworkdata.org

Summary

Dr. Michael J. Walsh is an experienced energy and sustainability expert with a strong background in research, technical analysis, stakeholder engagement, and project leadership. As Managing Partner of Groundwork Data, he supports the transition to cleaner energy systems through research, stakeholder engagement, and expert testimony.

Professional Experience

Groundwork Data Inc., Arlington, MA, Managing Partner and Founder, 2021 – Present.

Established a consultancy focused on supporting the transition to cleaner and more resilient energy systems. Performs research, technical analysis, and stakeholder engagement to contribute to expert testimony, reports, and outreach about the future of gas, electrification, decarbonization, and alternative fuels.

The Cadmus Group., Boston, MA, Senior Associate, 2019 – 2020.

Served as a technical decarbonization specialist within a state and local policy practice group, overseeing project coordination, expert-level analysis, and quantitative research. Responsibilities encompassed a diverse range of initiatives, such as the development of comprehensive climate action plans, the evaluation of efficiency programs, and the preparation of natural carbon inventories.

Boston University Institute for Sustainable Energy, Boston, MA. Senior Research Scientist, 2017 – 2019.

Lead researcher and project manager for an academic research institute. Primarily oversaw the development of a multi-report city decarbonization study.

Bentley University Center for Integration of Science and Industry, Waltham, MA. Research Fellow (2013-2017).

Participated in a multi-university, federally-funded research consortium investigating advanced biofuel and food product pathways. Conducted techno-economic, lifecycle, and integrated energy assessments of novel technologies. Supported the center's research into understanding the drivers of technological change.

Education

Ph.D. in Environmental Engineering, Cornell University, Ithaca, New York (2013)

B.A. in Chemistry (Honors), Colby College, Waterville, Maine (2005)

Selected Projects

The Future of Gas: Regulatory Interventions. Dr. Walsh is a nationally recognized authority in developing regulatory strategies for the evolving gas sector. Through research conducted in New York, Illinois, and Massachusetts, he has identified three challenges facing utility gas service: rising infrastructure costs, climate initiatives, and increased competition from alternative gas technologies. Dr. Walsh has contributed his expertise to proceedings addressing the future of gas in Massachusetts, Rhode Island, Colorado, and Illinois, serving multiple public interest organizations and governmental entities.

Integrated Energy Planning. Recognizing the increasing challenges associated with the gas system, Dr. Walsh developed the "Local Energy Asset Planning Framework" in 2022, accompanied by a white paper that describes how various datasets can be used to inform and design strategies for targeted electrification, non-pipeline alternatives, and integrated energy planning. Subsequently, he authored a series of technical studies that described progressive improvements and applications of the framework, demonstrating the cost-effectiveness of avoiding pipeline replacement and strategies for sourcing such opportunities. The LEAP framework has been used to support testimony. It is under continued development under Dr. Walsh's oversight. Additionally, he has supported the Commonwealth of Massachusetts in three working groups focused on non-pipeline alternatives, integrated energy planning, and the future role of the Everett Marine Terminal Liquified Natural Gas Facility in supporting utility gas and electric sector needs.

Massachusetts 2050 Decarbonization Roadmap. Dr. Walsh led a comprehensive multi-sector technical research and stakeholder engagement initiative for the Massachusetts Executive Office of Energy and Environmental Affairs. In this capacity, he coordinated a team of 40 professionals across 10 organizations, focusing on greenhouse gas mitigation strategies and their effects across transportation, buildings, electric, non-energy, and land use sectors. This project has played a critical role in shaping Massachusetts' climate policy.

Boston's Climate Planning: Carbon Free Boston (2019) and the Boston Climate Progress Report (2022). Dr. Walsh has been instrumental in advancing Boston's climate planning initiatives, including his leadership on the Carbon Free Boston Study (conducted for the Boston Green Ribbon Commission in 2019) and the Boston Climate Progress Report (prepared for the Boston Foundation in 2022). As part of the Carbon Free Boston Study, Dr. Walsh represented the Boston University Institute for Sustainable Energy, where he coordinated a multidisciplinary team of researchers and consultants to perform a comprehensive, pioneering analysis of municipal decarbonization strategies. For the Boston Climate Progress Report, he partnered with the Dukakis Center at Northeastern University to thoroughly evaluate both mitigation and adaptation efforts, highlighting critical transformation areas and identifying four major initiatives required for accelerated progress. Additionally, Dr. Walsh has provided pro bono climate action advice to organizations such as the New England Aquarium, Livable Streets Alliance, the Boston Foundation, and Boston University.

Bioenergy and Advanced Waste Energy Recovery Technologies - Dr. Walsh possesses significant expertise in engineering and policy related to bioenergy and waste management systems. His doctoral research involved developing bioreactors designed to scale up algae production for bioenergy applications. Subsequently, his postdoctoral work concentrated on advancing technologies within the bioenergy sector, including analysis of commercialization strategies, technoeconomic assessments, and lifecycle evaluation of various bioenergy pathways. Dr. Walsh has collaborated with the Pacific Northwest National Laboratory to develop bioenergy pathways for integrated energy planning software and conducted an extensive stakeholder engagement initiative focused on emerging waste management strategies in the Metro Boston Region. In the private sector, his experience includes conducting life cycle analyses for consumer-grade composting devices and reviewing sustainability plans for major waste management organizations.

Expert Testimony and Participation in Regulatory Proceedings

Colorado Public Utilities Commission (25A-0220G): Provided direct testimony regarding Xcel Energy's 2025-2030 Gas Infrastructure Plan. On behalf of Rewiring America. November 2025.

Massachusetts Department of Public Utilities (25-41 through 25-44/45): Provided direct and surrebuttal testimony regarding the Massachusetts Local Distribution Companies' 2025 Climate Compliance Plans. On behalf of Rewiring America. September 2025.

Rhode Island Public Utilities Commission (25-55-NG): Provided direct testimony regarding The Narragansett Electric Co. d/b/a Rhode Island Energy - FY 2026 Gas Infrastructure, Safety and Reliability (ISR) Plan, n behalf of the Conservation Law Foundation, February 2025.

Rhode Island Public Utilities Commission (23-49-NG): Provided direct testimony regarding The Narragansett Electric Co. d/b/a Rhode Island Energy - FY 2026 Gas Infrastructure, Safety and Reliability (ISR) Plan, On behalf of the Conservation Law Foundation, February 2024.

Massachusetts Department of Public Utilities (20-80): Provided a technical comment on the practice of offering Line Extension Allowances by Massachusetts Gas Local Distribution Companies. On behalf of Sierra Club, Conservation Law Foundation, and CLF, August, 2024.

Rhode Island Public Utilities Commission (22-01-NG): Provided comments and meeting participation in the "Future of Gas" Investigation. On behalf of Conservation Law Foundation and Sierra Club, 2023-2024.

Massachusetts Department of Public Utilities (22-32): Provided testimony on the petition of Liberty Utilities for Approval of an Agreement to Purchase Renewable Natural Gas from Fall River RNG LLC. On behalf of Conservation Law Foundation, June 2022

Massachusetts Department of Public Utilities (20-80): Provided a technical comment on the Local Distribution Companies Independent Consultant Report's pathways analysis. May 2021.

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Walsh, M.J., Ahner, B.A. (2013). Determination of stability constants of Cu(I), Cd(II) & Zn(II) complexes with thiols using fluorescent probes. Journal of Inorganic Biochemistry, 128, 112-123. https://doi.org/10.1016/j.jinorgbio.2013.07.012

Kim, H.S., **Walsh**, M.J., Yang, H., Ahner, B.A. (2011). Nutrient availability alters levels of non-translationally synthesized nitrogen-rich dipeptides in Emiliania huxleyi. Aquatic Biology, 12, 215-224. https://doi.org/10.3354/ab00335

Vadas, T.M., Fahey, T.J., Sherman, R.E., Demers, J.D., Grossman, J.M., Maul, J.E., Melvin, A.M., O'Neill, B., Raciti, S.M., Rochon, E.T., Sugar, D.J., Tonitto, C., Turner, C.B., **Walsh**, M.J., Xue, K. (2007). Approaches for analyzing local carbon mitigation strategies: Tompkins County, New York, USA. International Journal of Greenhouse Gas Control, 1(3), 360-373. https://doi.org/10.1016/S1750-5836(07)00041-2

Selected Media Apperances

Dr. Walsh is a frequent source of media expertise on energy, climate, and environmental matters

Television & Broadcast Media

WCVB Boston (Channel 5) (November 6, 2022). "Report: Boston falling short when it comes to fighting climate change." Live interview. https://www.wcvb.com/article/boston-climate-progress-report-michael-walsh-interview/41879378

CBS Boston (January 30, 2019). Carbon Free Boston study suggests $5 fee for driving into the city." https://www.cbsnews.com/boston/news/carbon-free-boston-study-suggests-5-fee-for-driving-into-the-city/

Podcast Appearances

The Public's Radio Possibly Podcast (2024, March 19). What does the future of natural gas look like in Massachusetts? Interview on Massachusetts gas utility policy. https://thepublicsradio.org/possibly-podcast/what-does-the-future-of-natural-gas-look-like-in-massachusetts/

Expert Commentary in Major Media

Energy News Network/Canary Media (November 13, 2024). "As Rhode Island considers future of gas, advocates call for 'realism' on cost, availability of RNG." https://www.canarymedia.com/articles/enn/as-rhode-island-considers-future-of-gas-advocates-call-for-realism-on-cost-availability-of-rng

Gas Outlook (March 21, 2023). Are hydrogen blending and RNG climate solutions? https://gasoutlook.com/analysis/are-hydrogen-blending-rng-really-climate-solutions/

Canary Media (March 20, 2023). "New York must chart new course for gas utilities to hit climate targets." https://www.canarymedia.com/articles/fossil-fuels/new-york-must-chart-new-course-for-gas-utilities-to-hit-climate-targets

The Boston Globe. (2022, November 3). "Boston's 2030 climate goal is out of reach, a new report finds." https://www.bostonglobe.com/2022/11/03/science/bostons-2030-climate-goal-is-out-reach-new-report-finds/

Boston Business Journal (November 2022). 40 Under 40: Michael Walsh
https://www.bizjournals.com/boston/c/bbj-2022-40-under-40/20736/40-under-40-michael-walsh.html

Boston Business Journal (September 28, 2022). Boston proposes new buildings should hit 'net zero' immediately.
https://www.bizjournals.com/boston/news/2022/09/28/bpda-netzero-immediately-proposal.html

Boston Globe (August 30, 2022). Maine court finds part of referendum blocking transmission line to Massachusetts unconstitutional.
https://www.bostonglobe.com/2022/08/30/science/maine-court-finds-referendum-blocking-transmission-line-massachusetts-unconstitutional/

Waste Dive (July 26, 2022). Can carbon capture make incinerators a net-zero solution? European operators aim to find out?
https://www.wastedive.com/news/can-carbon-capture-make-incinerators-a-net-zero-solution-european-operator/626807/

WBUR News. (November 4, 2022). "Boston not on track to reach carbon reduction goals, new report finds."
https://www.wbur.org/news/2022/11/04/boston-massachusetts-fails-to-reach-carbon-emissions-reduction-goals-emissions

NBC Boston (November 3, 2022). "Boston off track on emissions reduction goal, report finds."
https://www.nbcboston.com/news/local/boston-off-track-on-emissions-reduction-goal-report-finds/2882387/

ecoRI News. (September 20, 2020). "Consultant: Carbon pricing not enough to stop R.I. emissions."
https://ecori.org/2020-9-20-carbon-pricing-not-enough-to-stop-emissions/

Additional Media Coverage & Institutional Features

The Boston Foundation. (November 3, 2022). "First Boston Climate Progress Report highlights progress, systemic obstacles to city's ambitious climate goals."
https://www.tbf.org/news-and-insights/press-releases/2022/november/2022-climate-progress-report-20221103-pr

Boston University. (May 20, 2019). "BU's Institute for Sustainable Energy Delivers Comprehensive Analysis: Carbon Free Boston." https://www.bu.edu/igs/2019/05/17/carbonfreeboston/

Bentley University. (July 2016). "At the Forefront of Sustainable Food, Bentley Research Fellow Brings Algae to the Table." https://www.bentley.edu/news/forefront-sustainable-food-bentley-research-fellow-brings-algae-table

Cornell Chronicle. (September, 2009). "Cornell's climate plan cuts carbon emissions to zero by 2050."
https://news.cornell.edu/stories/2009/09/cornell-unveils-its-climate-neutrality-plan

Opinion Editorials

Boston Globe (July 26, 2024). "Heat pumps are the pathway to energy affordability."
https://www.bostonglobe.com/2024/07/26/opinion/heat-pumps-epa-award-climate-change/

Commonwealth Beacon (April 3, 2024). "No more climate legislation needed - it's time for action."
https://commonwealthbeacon.org/opinion/no-more-climate-legislation-needed-its-time-for-action/

Commonwealth Magazine (May 11, 2023). "How the gas system can adapt to net-zero future." https://commonwealthbeacon.org/opinion/how-the-gas-system-can-adapt-to-net-zero-future/

Selected Talks

Panelist, "Future of Gas 101: A Panel Discussion with Experts," Climate Xchange, October 28, 2025.

Presenter, "Perspectives for Decarbonizing the Peak Focus Area Working Group from the MA 2050 Roadmap and other relevant research & analysis," Massachusetts Office of Energy Transformation Expert Presentation Series: Renewable Fuels, June 17, 2025. https://www.youtube.com/watch?v=ioKrDyJU8yk

Presenter, "Neighborhood Electrification," MassCEC Thoughtful Climate Live Interview Series (Interview with Galen Nelson), April 18, 2025. https://www.youtube.com/watch?v=GjA-NI6xo00

Invited Speaker, "The Boston Foundation's 2024 Climate Progress Report Convening," The Boston Foundation, October 16, 2024.

Invited Speaker, "The Future of Gas and Gas Policy," NESCAUM Building Electrification Task Force Meeting, October 1, 2024.

Presenter, "Pipeline Extension Allowances and the Transition Beyond Gas in Massachusetts," webinar hosted by Conservation Law Foundation, Sierra Club, and Environmental Defense Foundation, October 9, 2024. https://www.youtube.com/watch?v=MYu-N2Si7Dw

Presenter, "Clearing the Air Gas," webinar hosted by Institute for Market Transformation for C40, August 27, 2024.

Presenter, "The Future of Gas and Tactical Thermal Transitions," Multitown Gas Leaks Initiative, May 2, 2024.

Presenter, "New Construction and Report Presentation," webinar hosted by Zero Carbon Massachusetts, March 14, 2024.

Presenter, "The Future of Gas in NY: Perspectives on RNG," New York State Department of Public Service Avoided Cost of Gas Working Group, September 3, 2023.

Presenter, "The Future of Gas in New York State," webinar hosted by Building Decarbonization Coalition, May 25, 2023.

Panelist, "NECEC Emerging Trends Series: Decarbonizing Building Heating," New England Clean Energy Council, January 23, 2023. https://www.youtube.com/watch?v=PAPYUt5ZbAo&t=4828s

Presenter, "Boston Climate Progress Report 2022," The Boston Foundation, November 3, 2022. https://www.tbf.org/news-and-insights/videos/2022/november/boston-climate-progress-report-forum-20221103

Keynote Presenter and Panelist, "Massachusetts' 2050 Roadmap: Transformations Needed to Achieve Net Zero," Environmental Business Council of New England, November 18, 2021.

Presenter and Panelist, "Designing a Carbon Free Boston," Boston Society for Architecture/American Institute of Architects, May 9, 2019. https://www.youtube.com/watch?v=frdnNvuNHYo

Presenter and Panelist, "Carbon Free Boston: Findings & Next Steps," A Better City, February 12, 2019.

Presenter, "Accounting for CO2 in Algae Cultivation," Algae Cultivation for Carbon Capture and Utilization Workshop, May 23, 2017.

Presenter, "Food and Energy from Marine Algae: Enabling deep transformation in agriculture & bioenergy," 9th Annual Integrated Assessment Modeling Consortium Meeting, Beijing, China, December 2016.

Presenter, "Financial and Integrated Assessment of Algae for Food and Energy," MIT Joint Program on the Science and Policy of Global Change Economic Projection and Policy Analysis Seminar, Cambridge, MA, November 2016.

Presenter and Panelist, "Creating Climate, Energy and Food Security Using Algae from the Sea," Bentley University Innovators Business Series, April 22, 2015. https://www.youtube.com/watch?v=NM2wTHtoaRs

Presenter, "Turning Research into Practice: Cornell University Climate Action Plan," United Nations Climate Change Conference COP 16 Side Event on Sustainable Agriculture and Terrestrial Carbon, Cancun, Mexico, November 2010.

Awards and Honors

Bishop Brady High School Distinguished Alumni Award (2024)

Boston Business Journal 40 under 40 (2022)

Bentley University Innovation in Teaching Award (2016)

New England Aquarium Young Professionals Advisory Committee (2014)

American Institute of Biological Sciences Emerging Public Policy Leadership Award Honorable Mention (2011)

Cornell University Board of Trustees, Student-Elected Member (2008-2010)

Cornell University Distinguished Student Volunteer Award (2007)

Colby College Coach's Award, Cross Country (2003)

Teaching Experience

Arlington Community Education

Course Instructor: Decarbonizing Massachusetts, Fall 2025

Bentley University, Waltham, MA

Adjunct Assistant Professor: Global Climate Change (NASE 337), Spring & Fall 2015

Adjunct Assistant Professor: Science of Sustainability (NASE 364), Spring 2014

Cornell University, Ithaca, NY

Teaching Assistant: Sustainable Development (BEE 3299), 2009-2012

Teaching Assistant: Engineering for a Sustainable Society (BEE 2510), 2007-2011

Graduate Resident Fellow: Hans Bethe House residential college, 2007-2008

Topic / Sub-Category	Massachusetts	New York	California	Colorado	Illinois	Michigan (Current State)
1. PROCEEDING PROCESS AND STRUCTURE						
Proceeding / Docket	DPU 20-80 ("Future of Gas" investigation)	Case 20-G-0131 (Gas Planning Procedures)	R.20-01-007 (Long-Term Gas Planning, 2020–2024, closed); R.24-09-012 (successor Long-Term Gas Planning, 2024–present); R.19-01-011 (Building Decarbonization). SB 1221 (Neighborhood Decarbonization Zones, Sep 2024). GO 177 gas infrastructure certification (Dec 2022).	SB 21-264 (Clean Heat Standard, 2021); SB 23-291 (LEA/depreciation reform, 2023); PUC Proceeding 23A-0392EG (Xcel CHP)	ICC Docket 24-0158 (Future of Gas)	No Future of Gas proceeding.
Date Initiated	October 29, 2020	March 19, 2020	R.20-01-007: Jan 2020 (predecessor gas planning, closed Sep 2024); R.19-01-011: Jan 2019 (Building Decarbonization); R.24-09-012: Sep 2024 (successor gas planning + SB 1221)	SB 21-264: June 2021 (signed); SB 23-291: June 2023 (signed)	March 7, 2024	N/A
Initiation Pathway	Regulatory: DPU own motion	Regulatory: PSC own motion (triggered by National Grid gas moratorium crisis, 2018–2019)	Combined: CPUC investigations + legislative (SB 1221, Sep 2024)	Legislative: General Assembly enacted Clean Heat Standard and follow-up reforms	Regulatory: ICC staff directed by Commission after four simultaneous gas utility rate cases in 2023	N/A
Key Order(s)	Order 20-80-B (Dec 6, 2023): landmark regulatory framework establishing "beyond gas" future	Gas Planning Order (May 12, 2022): adopted gas system planning process with LTP requirement	D.22-09-026 (Sep 2022): LEA elimination; D.23-12-037 (Dec 2023): mixed-fuel LEA elimination; GO 177 (Dec 2022): gas infrastructure certification for projects ≥$75M; Staff decommissioning framework proposal (Dec 2022). SB 1221 signed Sep 2024. R.24-09-012 opened Sep 2024.	PUC Xcel CHP approval (C24-0397, June 2024): $440M plan. PUC GIP guidance (C24-0092, Feb 2024): found Xcel GIP "inadequate," directed NPA competitive solicitation. 2035 target rulemaking (Dec 2025): 41% reduction by 2035.	No formal order yet. Phase 1 workshop report (Jul 2024); Phase 2C workshops underway (Dec 2025–May 2026); final report anticipated late 2026. ICC Feb 2025 order restricted Peoples Gas SMP.	MPSC Nov 2024 order (U-21291) directed DTE to file updated GDP incorporating energy transition pathways. No order for a broader FOG study.
Timeline / Current Phase	Framework established (Dec 2023). Implementation phase: Climate Compliance Plan dockets open (D.P.U. 25-40 through 25-45). LEA interlocutory order issued directing utilities to file revised tariffs removing LEAs by Oct 20, 2025. OTS reform under active discussion (S. 2967 empowers DPU to broadly modify OTS). TEN pilots operational (Eversource Framingham) and expanding.	LTP filings ongoing across all utilities. Central Hudson LTGP order (Jul 2025): directed utility to reduce gas consumption, propose DR pilots, develop NPAs. National Grid LTGP order (Sep 2025): directed NPA updates, bill impact analysis, customer termination reporting. NYSEG/RG&E: developed leak-prone pipe replacement via full electrification NPA strategy. Con Edison: proposed "hard to electrify" customer definition. NFG: Highland Drive NPA RFP (Jan 2025). A8888/S8417 signed into law Dec 19, 2025, eliminating 100-foot rule gas LEA subsidy.	R.24-09-012 active with three phases: Phase 1 (Interim Actions, Nov 2024–present); Phase 2 (Long-Term Gas Transition Planning, Q1-2 2025); Phase 3 (SB 1221 Implementation). Pipeline replacement maps submitted July 2025 by PG&E, SoCalGas, SDG&E, Southwest Gas. Priority decarbonization zone designations added July 21, 2025. Advocates raised concerns about map granularity. CPUC designated initial Priority Neighborhood Decarbonization Zones (D.25-12-042, Dec 18, 2025). Pilot program rules due July 2026.	Xcel CHP approved June 2024 (covers 2024–2027). Next CHP due 2026 (must address 2030 22% target). 2035 targets finalized Dec 2025 (41%). Xcel 2025 GIP filed (litigated proceeding 25A-0220G). PUC found first GIP "inadequate" for NPA consideration; directed Xcel to run competitive NPA solicitations.	Phase 2B commenced March 2025. Pilot Working Group evaluated 100+ decarbonization pilot proposals; 10 pilot types selected (residential combination, neighborhood/targeted combination, TEN combination, industrial electrification, agricultural heat pump, hybrid rooftop units, RNG combination, culinary arts kitchen electrification, methane pyrolysis, commercial water heater). Decarbonization Pathways Working Group active. Long-Term Gas Infrastructure Plans required biennially starting mid-2026. ICC final report anticipated late 2026.	N/A
Key Participating Parties / Intervenors	DPU (regulator); MA Attorney General (filed comprehensive regulatory framework); six LDCs (Eversource, National Grid, Berkshire Gas, Unitil, Liberty, New England Gas); CLF; EDF; Sierra Club; Acadia Center; E3/ScottMadden (independent consultants)	PSC (regulator); DPS Staff; Con Edison; National Grid (KEDNY/KEDLI); NFG; NYSEG/RG&E; Liberty SLG; NYC; Westchester County; NRDC; Sierra Club; BDC; EDF; CRA (independent assessor)	CPUC (regulator); PG&E; SoCalGas; SDG&E; NRDC; Sierra Club; Earthjustice; CEC; BDC; TURN (consumer advocate); Legislature (SB 1221)	CO PUC (regulator); Xcel Energy; Black Hills; Atmos; CO Energy Office; SWEEP; Sierra Club; Mi Familia Vota; Legislature	ICC (regulator); ICC Staff; Peoples Gas; Nicor Gas; Ameren IL; North Shore Gas; CUB; NRDC; Sierra Club; Groundwork Data; Environmental Law & Policy Center; Celia Johnson Consulting (facilitator)	N/A
Independent Consultant / Assessment	E3 and ScottMadden retained by LDCs at DPU direction (ICR, Mar 2022). Eight decarbonization pathways analyzed. NARUC (May 2025) notes this model — where LDCs are directed to retain independent consultants — as one approach to addressing information asymmetry.	Charles River Associates (CRA) retained by DPS Staff to independently assess utility LTP quality and assumptions. NARUC (May 2025) identifies NY as unique among state gas planning rules for requiring independent third-party assessment. NARUC notes costs may be justified through condensed timelines and improved plan quality.	E3 conducted foundational CA retail gas study for CEC (2020). CPUC and CEC staff conducted independent analysis for R.24-09-012. Joint Agency White Paper (Feb 2024) by CPUC, CEC, and CARB staff. Independent facilitators for multi-stakeholder technical workshops.	E3 supported Xcel CHP development (Clean Heat Portfolio Model). PUC directed modifications to E3 modeling of DSM and BE resource costs. PUC required ratepayer impact measure (RIM) test and broader societal benefits examination in future filings (per NARUC).	Celia Johnson Consulting retained as independent facilitator for FOG workshops. No independent consultant retained for utility plan review. Two working groups established for Phase 2B: (1) Decarbonization Pathways Working Group and (2) Pilots Working Group (per ICC Staff Report, Dec 2025).	CUB/DH Infrastructure produced independent revenue requirement analysis report (Mar 2025). Groundwork Data updated analysis based on U-21973 is included in this testimony.
2. DEMAND FORECASTING						
Formal Demand Study	Yes. E3/ScottMadden Independent Consultant Report (Mar 2022). Eight decarbonization pathways ranging from full system decommissioning to high electrification to hybrid heating to high RNG.	Required in Long-Term Plans: 20-year gas demand forecast mandatory for each LDC. Three scenarios required. Individual utility studies being filed 2023–2025; CRA reviews assumptions independently.	Yes. E3 "Challenge of Retail Gas in CA's Low-Carbon Future" (2020) for CEC. Modeled gas demand decline under multiple scenarios through 2050. CEC also produces official gas demand forecasts. Updated analysis in R.24-09-012.	Embedded in Clean Heat Plan modeling. E3 Clean Heat Portfolio Model for Xcel evaluates demand reduction from electrification, efficiency, and alternative fuels. Xcel projects need to electrify 38,000 SF homes and 6,000 MF units in 2027 alone.	Not yet completed. ICC FOG proceeding has not produced formal demand study. Synapse Energy "Snapshot of IL Energy Landscape" provides context. Long-Term Gas Infrastructure Plans (starting mid-2026) will include demand forecasts.	Not completed. DTE demand forecasting does not incorporate climate-aligned or electrification scenarios.
Scenarios Modeled	Eight pathways: (1) gas system decommissioning; (2) high electrification; (3) moderate electrification; (4) hybrid heating; (5) high RNG; (6) high hydrogen; (7) networked geothermal; (8) reference case. DPU did not select preferred pathway but framework tilts toward electrification.	Three mandatory per LTP: (1) business-as-usual; (2) low-carbon transition; (3) no-new-infrastructure (larger utilities). At least one scenario must demonstrate meeting demand with no new infrastructure. Utilities may propose additional scenarios.	Multiple: E3 modeled high electrification, high RNG, hybrid, and reference scenarios. Key finding: gas rates reach unsustainable levels after 2030 under all scenarios. Even high electrification leaves millions on gas system through 2050.	Clean Heat Plan scenarios: target achievement vs. 2.5% cost cap compliance vs. alternative portfolios. E3 modeled electrification, efficiency, recovered methane, hydrogen, certified gas, and carbon offsets. PUC approved electrification-heavy portfolio.	Not yet developed within FOG proceeding. Groundwork Data presentation to ICC (May 2024) showed gas delivery costs rising 45% by 2030 even with stable customer base. Formal scenario analysis anticipated in Phase 2/LTGIPs.	Groundwork Data revenue model covers seven demand scenarios including four different decarbonization pathways. DTE has not produced equivalent analysis.

Key Assumptions	Heat pump adoption rates; building code changes; gas and electric rate trajectories; appliance replacement timing; climate policy stringency; federal incentives. E3 found building electrification lower-cost and lower-risk than alternatives.	CLCPA compliance requirements (40% by 2030, 85% by 2050); building code changes (All-Electric Buildings Act, 2023; implementation originally Jan 2026 but implementation voluntarily delayed pending Second Circuit appeal (2025); heat pump costs and performance; gas rate trajectory; load diversity assumptions.	CEC official demand forecasts; building code trajectory (Title 24); LEA policy impact (80% all-electric after LEA elimination); heat pump adoption curves; gas rate escalation; RNG/hydrogen supply constraints.	GHG reduction targets (4% by 2025, 22% by 2030, 41% by 2035); 2.5% annual cost cap (exceeded in approved plan); federal incentive availability (IRA rebate uncertainty); market transformation rates for heat pumps.	CEJA clean energy goals; building electrification rates; gas system maintenance cost trajectory; population/customer projections. ICC noted key assumption gaps in stakeholder presentations.	DTE assumes 20-year revenue horizon, current rates, no demand decline in CAP model. No climate policy assumptions. No electrification adoption curves. GWD inputs detailed within model.
Key Results / Findings	All pathways show declining gas throughput. Electrification pathway most cost-effective. Hybrid heating "not convincing" per DPU. RNG supply insufficient for building heating. Full decommissioning achievable but requires significant upfront investment.	Undepreciated gas plant doubled from $13B to $29B over 10 years. Pipeline replacement: $28B minimum statewide at ~$6M/mile. 9 of 10 miles installed are replacements. Demand decline will strand assets.	Gas rates reach unsustainable levels after 2030 without transition strategy. Targeted electrification could avoid $20B in pipeline costs through 2045. Meeting building demand with RNG would require ~2x all NY cropland (per GWD).	Electrification and efficiency found most cost-effective by PUC. Hydrogen: $174–$260/ton. RNG: $244–$286/ton. PUC approved no hydrogen budget. Rejected certified gas and offsets as non-additional. CHP projected $100M/year customer savings.	Gas delivery costs rising 45% by 2030 even with stable customers (GWD). Peoples Gas SMP: $1.4B initial estimate → $12.8B projected total. 1 in 5 customers delinquent. Formal demand study results pending.	Groundwork Data revenue requirement model used in this testimony: residential bills +15% (real 2025$) by 2050 under current trajectory. Total CAPEX: ~$29.7B through 2050. DTE has produced no equivalent analysis.
3. TECHNOLOGY EVALUATION						
Electrification Assessment	DPU framework strongly favors electrification. "Not convinced" hybrid heating viable. Cold climate heat pump technology acknowledged as sufficient for most applications. TEN pilots (Eversource Framingham, National Grid Lowell/Boston) as utility-led electrification pathway.	Gas Planning Order requires NPA evaluation including electrification. Con Edison Gas DR pilot (2025–2028) uses thermostat-based load control. NFG issuing NPA RFPs for specific neighborhoods. Electrification central to CLCPA compliance.	Most advanced operational experience. PG&E completed 100+ electrification projects cheaper than gas pipe replacement. SB 1221 authorizes 30 neighborhood decarb zones with free electric appliances. After LEA elimination, 80% new construction all-electric.	Electrification is centerpiece of approved CHP. PUC found BE and efficiency "most cost-effective and promising measures." Goal: ~100,000 heat pump installations by end of 2026. 20% of incentives reserved for LMI.	Electrification discussed in FOG workshops. Phase 2B Pilot Working Group selected "Residential Combination" and "Neighborhood/Targeted Combination" pilot types. No formal mandate yet. ICC stated "the gas distribution system must change" despite CEJA not explicitly granting ICC gas sector authority.	No formal electrification assessment by DTE or MPSC. DTE not required to evaluate NPAs.
RNG Assessment	DPU does not support regulatory changes enabling LDC procurement of RNG. Supply limited, costly, better used in hard-to-electrify sectors.	RNG evaluated in LTP scenarios. Supply constraints documented: meeting NY building demand with RNG would require ~2x all NY cropland (GWD). Not considered viable at scale for buildings.	E3: RNG 7–9x more costly than fossil gas through 2050. Purpose-grown crops excluded due to sustainability concerns. Limited to recovered methane from waste sources. Best for industrial, not buildings.	PUC approved only recovered methane ($10M budget). Rejected certified gas and carbon offsets as non-additional. RNG cost: $244–$286/ton emission reduction. Not considered cost-effective.	ICC expressed skepticism of voluntary RNG tariffs. No formal RNG assessment within FOG proceeding. ICC terminated Nicor's TotalGreen voluntary RNG/carbon offset program after only 238 of 2.3M customers enrolled in three years (<0.01% participation). ICC also rejected Ameren's biomethane proposal as failing to demonstrate cost-effective emissions reduction.	DTE references RNG as decarbonization tool without analytical foundation comparable to other states.
Hydrogen Assessment	DPU expressed skepticism. Safety concerns, low blending limits, does not justify pipeline investments. Not supported as building heating solution.	Evaluated in LTP scenarios. Gas Planning Order requires analysis. Not currently favored for building applications. Better suited to industrial uses.	E3 analysis: hydrogen not cost-effective for building heating. Technical challenges with pipeline compatibility. Not a significant component of current proceedings.	PUC approved no hydrogen budget in Xcel CHP. Cost: $174–$260/ton emission reduction. Found not cost-effective for buildings. Hydrogen resources rejected entirely from approved plan.	Hydrogen discussed in FOG workshops. No formal regulatory position yet. Limited activity.	DTE references hydrogen as potential pathway without cost-effectiveness analysis or technical feasibility study. No comparison to electrification costs.
Thermal Energy Networks (TENs)	Most advanced. Eversource networked geothermal pilot in Framingham (operational). National Grid launched pilot in Boston (Franklin Field). SB 2249 (2025) proposed shifting gas utility spending from pipeline replacement to TENs and requiring joint gas-electric thermal transition plans. DPU encourages additional TEN pilots.	Under development as NPA option within gas planning proceeding. Utility Thermal Energy Network and Jobs Act (2022) mandated pilots from 7 largest utilities. 9 pilot projects advanced to Stage 2 (engineering design) including Con Edison (Chelsea, Mount Vernon, Rockefeller Center), National Grid (Syracuse, Brooklyn, Troy), O&R (Haverstraw), NYSEG (Ithaca), RG&E (Rochester). Six complete Stage 2 engineering filings submitted (July 2025). No operational pilots yet but construction decisions pending.	Not a major focus of current proceedings. Individual utility filings may include geothermal components.	Xcel committed to studying/piloting TENs. Local governments pushing for geothermal. Not yet a significant regulatory component.	Discussed in FOG workshops. Phase 2B Pilot Working Group selected "Thermal Energy Network Combination" as one of 10 pilot types.	Ann Arbor ARCA includes geothermal development commitments from DTE. No statewide TEN framework. No operational pilots.
Non-Pipeline Alternatives (NPAs) Framework	Strongest framework. Order 20-80-B requires utilities to demonstrate NPAs were "adequately considered and found non-viable or cost-prohibitive" before gas infrastructure cost recovery. Burden of proof on utility.	Gas Planning Order requires NPA analysis in all Long-Term Plans. Con Edison Gas DR pilot. NFG Highland Drive NPA RFP (Jan 2025). CRA independently assesses NPA evaluations.	Cost-based approach: PG&E implements NPAs where electrification costs less than pipeline replacement (100+ projects). SB 1221 scales this to neighborhood level with 30 authorized pilots.	Gas Infrastructure Plans must include NPA consideration aligned with CHP. PUC found first GIP "inadequate" for NPA analysis (Decision C24-0092, Feb 2024). Directed Xcel to run competitive solicitation for future NPAs. PUC responded favorably to two proposed NPAs, noting significant benefits and cost savings.	NPAs identified as priority topic in FOG workshops. Phase 2B Pilot Working Group evaluated 100+ pilot proposals. Long-Term Gas Infrastructure Plans (starting mid-2026) will require "comparative evaluations of resource procurements and major capital investments." NYSEG/RG&E developing NPA electrification strategy for leak-prone pipe replacement provides model.	DTE not required to evaluate NPAs. No NPA framework exists in MI.
4. STRANDED ASSET AND DEPRECIATION ANALYSIS						
Depreciation Study Ordered / Required	Yes. Order 20-80-B directed all LDCs to forecast potential magnitude of stranded investments and identify impacts of accelerated depreciation + alternatives. First-of-kind regulatory direction at scale.	Avoided Cost of Gas Working Group established to evaluate depreciation and stranded asset approaches. LTPs must include asset life assumptions. No standalone depreciation order yet.	CPUC evaluating proportional depreciation tied to CEC gas demand forecasts in R.24-09-012. Gas utilities plan $43B in fossil infrastructure through 2045 (per NRDC). Approach links depreciation to official demand forecasts.	SB 23-291 required depreciation study as part of broader gas transition reform. Study examines accelerated depreciation options for gas assets.	No depreciation study ordered. FOG proceeding may address in future phases. Long-Term Gas Infrastructure Plans (starting mid-2026) may include asset life analysis.	No depreciation study ordered. DTE's undepreciated gas plant balance growing.

Stranded Asset Risk Assessment	DPU explicitly recognized stranded asset risk. Framework creates presumption against gas expansion. Climate Compliance Plans must address asset recovery timeline. AG framework recommended comprehensive stranded cost analysis. Gas companies supplied "Transition Cost Studies" as part of their climate compliance plan filings that explored several cost recovery mechansims under varying scenarios of decline.	Groundwork Data documented: undepreciated balance doubled ($13B→$29B in 10 yrs). $5B added since CLCPA. $28B pipeline replacement liability. Stranded asset risk is central concern of gas planning proceeding.	E3 found gas decommissioning + electrification could avoid $20B in pipeline costs through 2045. SB 1221 enables targeted decommissioning to reduce stranded cost exposure. R.24-09-012 addresses systematically.	Gas Infrastructure Plan tension: Xcel's 2025 GIP proposes $2.85B in gas infrastructure spending (2025–2029, ~$570M/year) vs. $440M in approved clean heat spending (2024–2027, ~$126M/year) — roughly 6.5x more on gas infrastructure than clean heat over comparable periods. 60% projected rate increase for gas customers 2025–2040 under current trajectory. SB 23-291 requires proactive assessment.	Peoples Gas SMP is a stranded asset cautionary tale: $1.4B initial estimate → $3.3B spent with only 38% complete ($12.8B current projection for total costs).ICC ALJs largely sided with Peoples Gas in their proposed order, but commissioners overruled them (Feb 2025), imposing a more restrictive order that refocused the program exclusively on highest-risk CI/DI pipe retirement by 2035. No systematic statewide stranded asset assessment.	No formal assessment. DTE undepreciated plant balance growing (mirrors NY trend). Groundwork Data revenue model quantifies risk.
Proposed / Adopted Mechanisms	Accelerated depreciation study underway. DPU framework allows cost recovery reform. AG recommended: securitization, regulatory asset treatment, and limiting shareholder recovery for investments made after climate risks became foreseeable.	Avoided Cost of Gas Working Group evaluating: accelerated depreciation, securitization, targeted decommissioning, net salvage adjustments. No final mechanisms adopted yet.	Proportional depreciation (tied to CEC demand forecasts) under evaluation. Securitization under consideration. SB 1221 enables targeted decommissioning of specific system segments. PG&E already decommissioning 22+ miles.	SB 23-291 required depreciation study. Voluntary disconnection penalties eliminated. Clean Heat Plan investments intended to reduce future stranded asset exposure by managing demand decline proactively.	ICC restricted Peoples Gas to highest-risk pipe replacement only (CI/DI by 2035). Ended automatic rider mechanism; annual rate hearings required. No broader stranded asset framework.	No mechanisms adopted or proposed. MPSC has not addressed gas stranded assets.
Equity / Affordability Protections	EJ Strategy forthcoming from DPU. DPU acknowledged affordability may worsen but unwilling to slow transition. Special attention to EJ community transition opportunities. TEN pilots target disadvantaged areas.	Con Edison Energy Affordability Guarantee pilot: full electrification + bill cap at 6% of household income. DAC incentive premiums in Gas DR program. Gas Planning Order requires equity analysis.	SB 1221 prioritizes disadvantaged communities. Free electric appliances for all residents in designated pilot zones. CPUC equity requirements in R.24-09-012.	20% of Xcel CHP customer incentive funds reserved for LMI and historically disadvantaged communities. Cost cap of 2.5% of annual gas bills (exceeded in approved plan — PUC found public interest justified).	IL adopted tiered income-based rate structure for gas rates (only second state nationally after CA). Peoples Gas customer affordability crisis: 150,000 households (1 in 5) more than 30 days delinquent; $74.5M total debt (Feb 2025). Long-Term Gas Infrastructure Plans must demonstrate "minimizing rate impacts, particularly on low-income and equity investment eligible communities."	No gas transition equity framework. Low-income customers on DTE gas system face growing cost burden as fixed costs spread across fewer customers. No targeted electrification for LMI.
5. OUTCOMES: RECOMMENDED POLICIES AND REGULATORY CHANGES						
Planning Requirements	Climate Compliance Plans required every 5 years from each LDC (CCP dockets D.P.U. 25-40 through 25-45 now open). Integrated Energy Planning required (ESMP Order D.P.U. 24-10, 24-11, and 24-12, Aug 2024). OTS reform under active discussion (S. 2967). DPU directed utilities to file revised LEA tariffs by Oct 20, 2025.	Long-Term Plans required every 3 years with 20-year horizon. Three scenarios mandatory (BAU, low-carbon, no-new-infrastructure). Independent third-party assessment (CRA) unique among states (per NARUC). Depreciation studies required under three scenarios. Avoided Cost of Gas Working Group active.	GO 177 requires CPCN for gas projects ≥$75M. Annual reports on planned investments >$50M over 10 years. SB 1221 requires annual utility maps of pipeline replacement projects + priority decarb zones. R.24-09-012 three-phase structure covering interim actions, long-term planning, and SB 1221 implementation. Staff decommissioning framework proposed five-tranche priority methodology.	Clean Heat Plans required every 4 years. Gas Infrastructure Plans required biennially (per NARUC). PUC found first GIP "inadequate" and directed significant improvements in transparency and NPA consideration. 2.5% annual cost cap for clean heat resources (exceeded in approved CHP — PUC found public interest justified it).	Long-Term Gas Infrastructure Plans required biennially starting mid-2026. Most detailed requirements of any state (per NARUC): 12 elements including distribution mapping, scenario analysis, EJ community locations, lowest societal cost demonstration, workpaper transparency, and stakeholder input summary. ICC final report anticipated late 2026.	Gas Delivery Plan update required by MPSC order, but GDP update does not include demand decline analysis, NPA evaluation, distribution mapping, scenario analysis, independent review, EJ analysis, or rate impact analysis.
Investment Criteria / NPA Requirements	NPA evaluation required before gas infrastructure cost recovery. Burden of proof shifted to utility. Gas promotion cost recovery prohibited. Special contracts limited to "unique and novel" circumstances.	NPA analysis required in all LTPs. Gas expansion must be justified against demand-side alternatives. Avoided Cost of Gas methodology under development.	Cost-based NPA comparison: electrification proceeds where cheaper than pipeline replacement. SB 1221 authorizes 30 neighborhood decarb zone pilots on this basis. Gas utilities plan $43B in fossil infrastructure — subject to increasing scrutiny.	CHP investments condition infrastructure spending. PUC found electrification and efficiency most cost-effective. Hydrogen and certified gas rejected from approved portfolios. Infrastructure must support, not undermine, CHP goals.	ICC restricted Peoples Gas to highest-risk pipe only (Feb 2025). Ended automatic cost recovery rider. Annual rate hearings with justification required. No statewide NPA mandate yet; expected from FOG proceeding.	No NPA requirement. DTE not required to justify gas infrastructure against alternatives.
Line Extension Allowance Reform	DPU interlocutory order (Q3 2025) directing utilities to file revised tariffs removing LEAs by Oct 20, 2025. LEA policies to be adjudicated in detail within each utility's CCP docket (D.P.U. 25-40 through 25-45). DPU acknowledged relationship between LEAs encouraging gas load growth and CCP objective of ensuring LDCs meet GHG targets.	NY utilities spent ~$200M/yr on gas extensions 2017–2023. A8888/S8417 passed legislature June 2025 eliminating 100-foot rule (signed into law Dec 19, 2025); first state to repeal a legislatively mandated gas LEA.	Gas LEAs eliminated July 2023 (CPUC D.22-09-026). Mixed-fuel electric LEAs eliminated July 2024 (D.23-12-037). Savings: ~$130M/year in allowances, refunds, and discounts (2021 data); CPUC estimated $164M/year total. Impact: 80% of new construction all-electric (based on PG&E and SDG&E 2023 numbers). First state to act.	Gas construction allowances eliminated by PUC rulemaking pursuant to SB 23-291 (2023). Utilities filed tariff changes in late 2023 (Atmos, Black Hills, CNG, Xcel). First state where legislation directed LEA elimination. Voluntary gas disconnection penalties also ended.	All four IL gas utilities use ≤60 ft footage allowance — very limited subsidy. SB 2269 (2025) to reform LEAs failed to advance. Not a current focus.	No LEA reform. DTE Customer Attachment Program uses 20-year NPV with current rates and no demand decline.
Depreciation / Stranded Asset Policies	Depreciation study ordered for all LDCs. Framework allows cost recovery reform tools including accelerated depreciation, securitization, and regulatory asset treatment.	Avoided Cost of Gas Working Group evaluating accelerated depreciation and related tools. No final policies yet.	Proportional depreciation tied to CEC demand forecasts under evaluation. Securitization under consideration. SB 1221 enables targeted decommissioning.	SB 23-291 required depreciation study. Voluntary disconnection penalty elimination reduces one stranded asset risk factor.	No formal depreciation policy. ICC restricted Peoples Gas program but no statewide framework.	No depreciation study or stranded asset policy.
Obligation to Serve Reform	S. 2967 (2024) empowers DPU to broadly modify OTS to align with GHG targets and public interest. DPU actively exploring whether this enables removal of gas service for clean energy replacement, or whether single holdout can block neighborhood-scale projects. Comments due Oct 2025. Most advanced OTS reform discussion nationally alongside CA SB	Gas Planning Order evaluates OTS in context of LTP scenarios. No formal OTS reform yet.	SB 1221 allows CPUC to relieve gas utility of OTS in pilot areas if adequate substitute service available. 2/3 property owner consent required. First state to address holdout problem.	SB 23-291 ended penalties for voluntary disconnection. Community-scale OTS not yet addressed.	No OTS reform activity.	OTS framework not examined in gas transition context. DTE has franchise obligations.
RNG/Hydrogen Policy	DPU does not support enabling LDC RNG procurement. RNG/hydrogen not supported as building heating solutions.	Evaluated in LTP scenarios but not favored for buildings. Supply constraints documented.	RNG 7–9x costlier than fossil gas (E3). Purpose-grown crops excluded. Limited role for recovered methane.	No hydrogen budget approved. Certified gas and offsets rejected. Only recovered methane ($10M). Electrification is primary pathway.	ICC skeptical of voluntary RNG tariffs. No formal policy.	DTE references RNG/hydrogen without analytical foundation.

Equity Framework	EJ Strategy forthcoming. EJ community transition opportunities prioritized. TEN pilots target disadvantaged areas.	Con Edison affordability guarantee (6% income cap). DAC incentive premiums. Equity analysis required in LTPs.	SB 1221 prioritizes disadvantaged communities. Free electric appliances in pilot zones.	20% of CHP incentives for LMI/disadvantaged communities. Income-based considerations in program design.	Tiered income-based gas rate structure adopted (second state nationally). Customer debt crisis at Peoples Gas underscores urgency.	No gas transition equity framework.
Observed Effects on Utility Behavior	LDCs filing Climate Compliance Plans and TEN pilots in response to Order 20-80-B. LEA reform shifting utility approach to new customer connections. Gas promotion spending halted. Utilities adjusting capital planning around NPA requirements.	Mixed results. Con Edison launched innovative Gas DR pilot ($3M+). NFG issuing NPA RFPs for specific neighborhoods (Highland Drive). NYSEG/RG&E developing leak-prone pipe NPA electrification strategy. Central Hudson directed to propose DR pilots and develop NPAs. However, National Grid filed $1.4B NESE pipeline expansion in LTGP. PSC's Sep 2025 order pushed back with specific directives but did not reject LTGP outright.	Strongest behavioral shift. After LEA elimination, 80% of new construction all-electric (based on PG&E and SDG&E 2023 numbers). PG&E proactively completed 100+ targeted electrification projects and supported SB 1221 legislation. Utility internalization of NPA cost logic is most advanced.	Xcel ramping heat pump installations toward 100,000 by end of 2026 — unprecedented pace driven by CHP mandate. Clean Heat Plan spending transforming contractor and supply chain markets. Early implementation challenges with market transformation pace.	ICC had to intervene directly to halt Peoples Gas SMP (Feb 2025 order). Phase 2B producing concrete pilot proposals (100+ evaluated, 10 types selected). Nicor Gas 2025 rate increase slashed 47% ($314M requested→$168M approved, Nov 2025). Ameren: 43% cut ($129M→$73M). ICC also terminated Nicor's TotalGreen RNG/offset program (238 customers after 3 years). This follows Nov 2023 decisions that slashed all four gas utility rate requests by 25–50%. ICC approach of aggressive spending review is producing results even without formal FOG framework completed.	No observable change in DTE gas planning or investment approach. DTE Gas Delivery Plan does not reflect climate-aligned transition.
Promising Practices / Developments to Monitor	CCP filings in D.P.U. 25-40 through 25-45 will provide most detailed picture of utility transition planning under comprehensive framework. LEA tariff revisions (due Oct 2025) and subsequent adjudication. OTS comments and DPU interpretation of S. 2967. TEN pilot performance data from Eversource and National Grid.	CRA independent assessment methodology and findings. Avoided Cost of Gas Working Group final methodology. National Grid NESE pipeline outcome. Con Edison Gas DR pilot first-year results. NYSEG/RG&E NPA electrification strategy outcomes. Implementation of 100-foot rule repeal.	SB 1221 first pilot approvals expected 2026 — concrete data on costs, logistics, community response. R.24-09-012 proportional depreciation methodology. Resolution of map granularity concerns raised by advocates. PG&E continued NPA cost comparison data.	Xcel 2030 compliance CHP due 2026 with updated cost data from first implementation years. 2035 target (41%) will require significant acceleration. Black Hills and Atmos CHP implementation. PUC review of actual vs. projected heat pump adoption rates. Xcel 2025 GIP litigation (25A-0220G).	ICC FOG final report anticipated late 2026. Long-Term Gas Infrastructure Plan first filings (mid-2026). Peoples Gas CI/DI replacement acceleration progress. Phase 2C legislative/regulatory proposals. Pilot Working Group final selections and implementation. Potential IL Clean Heat Standard legislation.	TBD
Variables Beyond Cost and Technology	Order 20-80-B requires gas utilities to consider environmental justice impacts in Climate Compliance Plans. EJ mapping used to prioritize transition investments. Health co-benefits from electrification acknowledged but not yet formally quantified in cost-effectiveness framework.	CLCPA requires use of social cost of carbon (value of carbon guidance) in evaluating utility investments. Gas Planning Order requires equity analysis in all LTPs. Central Hudson LTGP order (Jul 2025) requires quantifying benefits to disadvantaged communities. PSC Sep 2025 National Grid order required customer termination reporting.	SB 1221 legislative findings explicitly reference health benefits: heat pump installation "particularly valuable in frontline communities to improve occupant comfort and increase resilience to heat waves." CPUC uses CalEnviroScreen for EJ mapping. Avoided methane emissions counted in cost-effectiveness.	PUC applies GHG cost adder in cost-effectiveness screening for CHP resources — explicitly priced carbon into compliance tool evaluation. PUC required RIM test and broader societal benefits examination in future filings (per NARUC). 20% LMI set-aside. PUC found public interest justified exceeding 2.5% cost cap.	CEJA establishes general emissions framework. Long-Term Gas Infrastructure Plans must include distribution mapping identifying EJ community locations and demonstrate "minimizing rate impacts, particularly on low-income and equity investment eligible communities." IL adopted tiered income-based gas rate structure (second state nationally).	MPSC proceedings do not incorporate social cost of carbon, health co-benefits, or environmental justice analysis.
KEY SOURCES AND CITATIONS						
See source links for each state →	• DPU 20-80 docket: mass.gov/info-details/investigation-assessing-the-future-of-natural-gas-in-massachusetts • Order 20-80-B: filed in DPU 20-80 docket • MA AG Framework: mass.gov/doc/ago-future-of-natural-gas-regulatory-framework-utility-and-technical-comments/download • GWD MA LEA Analysis (Oct 2024): groundworkdata.org • CCP dockets: D.P.U. 25-40 through 25-45 • S. 2967 OTS reform: 2024 MA legislative session • NARUC report (May 2025): pubs.naruc.org/pub/B3E9420C-9813-1958-98BB-C5387B4E2A9C • ESMP Order: D.P.U. 24-10/24-11/24-12 (Aug 29, 2024); mass.gov/info-details/electric-sector-modernization-plans-order-findings • SB 2249 bill page: https://malegislature.gov/Bills/194/S2249	• Case 20-G-0131 docket: documents.dps.ny.gov • Gas Planning Order (May 2022): S&P Global summary • GWD Future of Gas in NYS (Mar 2023): groundworkdata.org • A8888/S8417 LEA bill: nysenate.gov • Central Hudson LTGP order (Jul 2025): Case 23-G-0676 • National Grid LTGP order (Sep 2025): Case 24-G-0248 • NARUC report (May 2025): pubs.naruc.org/pub/B3E9420C-9813-1958-98BB-C5387B4E2A9C • Governor Hochul signing press release: https://www.governor.ny.gov/news/governor-hochul-signs-legislation-eliminate-unfair-utility-subsidy-passes-buck-new-residential • BDC New York Policy Updates page: https://buildingdecarb.org/new-york-policy-updates • Utility Thermal Energy Network and Jobs Act (UTENJA) docket, Case 22-M-0429	• R.24-09-012 and D.25-12-042 via CPUC Long-Term Gas Planning Rulemaking page: https://www.cpuc.ca.gov/industries-and-topics/natural-gas/long-term-gas-planning-rulemaking • D.22-09-026 (Sep 2022): CPUC LEA elimination • GO 177 (Dec 2022): docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K396/499396103.PDF • SB 1221: leginfo.legislature.ca.gov • CPUC SB 1221 implementation: cpuc.ca.gov/industries-and-topics/natural-gas/sb-1221-implementation • E3 CA gas study: energy.ca.gov • Joint Agency White Paper (Feb 2024): docs.cpuc.ca.gov • BDC Flipside Report: buildingdecarb.org • NARUC report (May 2025): pubs.naruc.org/pub/B3E9420C-9813-1958-98BB-C5387B4E2A9C	• SB 21-264 (2021): CO Clean Heat Standard leg.colorado.gov/bills/sb21-264 • SB 23-291 (2023): LEA elimination, depreciation study leg.colorado.gov/bills/sb23-291 • PUC Clean Heat Plans: puc.colorado.gov/cleanheatplans • PUC 2035 Target: puc.colorado.gov/press-release/fact-sheet-2035-clean-heat-plan-target • PUC Gas Infrastructure Plans: puc.colorado.gov/gas-infrastructure-plans • PUC Decision C24-0092 (GIP guidance): via CO PUC e-filings • PUC Decision C24-0397 (CHP approval): via CO PUC e-filings • NARUC report (May 2025): pubs.naruc.org/pub/B3E9420C-9813-1958-98BB-C5387B4E2A9C • CO Communities for Climate Action op-ed (Dec 2025): dailycamera.com/2025/12/27/xcel-gas-clean-heat-local-governments-climate-change-colorado-boulder-opinion/ • SB 21-264 bill page: leg.colorado.gov/bills/sb21-264 • Sierra Club CHP approval press release (Jun 2024): sierraclub.org/press-releases/2024/07/xcel-s-clean-heat-plan-approved-major-climate-wins	• ICC Docket 24-0158: icc.illinois.gov/docket/P2024-0158 • ICC FOG workshop page: icc.illinois.gov/programs/Future-of-Gas-Workshop • Phase 2 Outline (Sep 2024): icc.illinois.gov • CUB Peoples Gas page: citizensutilityboard.org/peoplesgasboondoggle • GWD/CUB Peoples Gas SMP report (Oct 2024): CUB website • Chicago Tribune (Jan 6, 2026): Peoples Gas rate increase filing • CEJA: ilga.gov • NARUC report (May 2025): pubs.naruc.org/pub/B3E9420C-9813-1958-98BB-C5387B4E2A9C • ICC FOG Phase 2 Plan (Feb 2026): icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/Phase%202%20Plan%20through%20May%202026_Final_2-5-26.pdf • ICC SMP Investigation Order press release (Feb 2025): illinois.gov/news/press-release.30954.html • ICC Pilots Working Group Staff Report (Dec 2025): icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/Future%20of%20Gas%20Pilots_12-31-25.pdf • Capitol News Illinois — Nicor/Ameren rate case (Nov 2025): capitolnewsillinois.com/news/icc-slashes-nicor-ameren-proposed-gas-rate-hikes-by-over-40/ • CUB SMP press release (Feb 2025): citizensutilityboard.org/blog/2025/02/20/cub-applauds-icc-for-pumping-brakes-on-controversial-peoples-gas-pipe-replacement-program/ • BDC Future of Gas in Illinois report (May 2024): buildingdecarb.org/wp-content/uploads/BDC-The-Future-of-Gas-in-Illinois.pdf	• MPSC U-21973 docket and discovery responses: mi-psc.my.site.com/s/case/500PH000009fHt0IAE/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 • MPSC Nov 2024 GDP Order (U-21291): michigan.gov/mpsc/commission/news-releases/2024/11/07/mpsc-approves-increase-in-bills-for-customers-of-dte • Advanced Energy United analysis of MPSC GDP order (Nov 2024): blog.advancedenergyunited.org/mpsc-order-paves-way-for-affordable-heating-for-dte-gas-ratepayers • DTE Gas Delivery Plan (2026–2035): filed in U-21973 docket • Groundwork revenue requirement model used in this testimony • CUB/DH Infrastructure CAPEX report (Mar 2025): filed in U-21973 docket

DTE Revenue Model — Insights Analysis

Even modest declines in customer counts will have an impact on DTE operations

Table 1.1: Real Monthly Bills (2025$) — Scenarios 0A, 0B, 1

Year	Scen 0A: Baseline	Scen 0B: Baseline	Scen 1: Mild
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

Table 1.2: % Difference in Real Monthly Bills vs Scenario 0A

Year	Scen 0B vs 0A	Scen 1 vs 0A
2025	0.0%	0.0%
2030	3.1%	3.6%
2035	5.8%	7.1%
2040	8.8%	10.8%
2045	11.9%	14.8%
2050	15.2%	19.0%

Table 1.3: Real Revenue Requirement per Customer ($/yr, 2025$) — Scenarios 0A, 0B, 1

Year	Scen 0A	Scen 0B	Scen 1
2025	$732.12	$732.12	$732.12
2030	$839.09	$877.11	$884.18
2035	$913.96	$989.40	$1,005.49
2040	$962.49	$1,078.92	$1,105.45
2045	$987.63	$1,146.40	$1,184.30
2050	$995.05	$1,196.01	$1,245.84

Table 1.4: % Difference in Real Rev Req/Customer vs Scenario 0A

Year	Scen 0B vs 0A	Scen 1 vs 0A
2025	0.0%	0.0%
2030	4.5%	5.4%
2035	8.3%	10.0%
2040	12.1%	14.9%
2045	16.1%	19.9%
2050	20.2%	25.2%

Table 1.5: Total Cost per Therm ($/therm, nominal) — Scenarios 0A, 0B, 1

Year	Scen 0A	Scen 0B	Scen 1
2025	$1.2635	$1.2635	$1.2635
2030	$1.5999	$1.6489	$1.6580
2035	$1.9688	$2.0834	$2.1079
2040	$2.3729	$2.5814	$2.6289
2045	$2.8112	$3.1461	$3.2260
2050	$3.2884	$3.7878	$3.9116

Table 1.6: % Difference in Total $/Therm vs Scenario 0A

Year	Scen 0B vs 0A	Scen 1 vs 0A
2025	0.0%	0.0%
2030	3.1%	3.6%
2035	5.8%	7.1%
2040	8.8%	10.8%
2045	11.9%	14.8%
2050	15.2%	19.0%

Ongoing gas customers face increasing risk if other customers migrate as part of climate action or technology preferences

Table 2.1: Real Monthly Bills (2025$) — Scenarios 3, 4, 5, 6

Year	Scen 3: Customer	Scen 4: 50% Elec	Scen 5: Full	Scen 6: 100%
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

Table 2.2: % Difference in Real Monthly Bills vs Scenario 0A

Year	Scen 3 vs 0A	Scen 4 vs 0A	Scen 5 vs 0A	Scen 6 vs 0A
2025	0.0%	0.0%	0.0%	0.0%
2030	9.5%	20.4%	17.2%	64.1%
2035	29.9%	80.5%	44.0%	116.9%
2040	55.9%	119.4%	87.8%	163.7%
2045	135.9%	160.2%	253.8%	207.2%
2050	149.4%	206.4%	N/A	249.0%

Table 2.3: Real Revenue Requirement per Customer ($/yr, 2025$) — Scenarios 3, 4, 5, 6

Year	Scen 3	Scen 4	Scen 5	Scen 6
2025	$732.12	$732.12	$732.12	$732.12
2030	$884.18	$974.56	$1,052.53	$877.11
2035	$1,005.49	$1,236.75	$1,484.11	$989.40
2040	$1,105.45	$1,518.68	$2,126.16	$1,078.92
2045	$1,184.30	$1,820.96	$4,370.31	$1,146.40
2050	$1,245.84	$2,178.92	N/A	$1,196.01

Table 2.4: % Difference in Real Rev Req/Customer vs Scenario 0A

Year	Scen 3 vs 0A	Scen 4 vs 0A	Scen 5 vs 0A	Scen 6 vs 0A
2025	0.0%	0.0%	0.0%	0.0%
2030	5.4%	16.1%	25.4%	4.5%
2035	10.0%	35.3%	62.4%	8.3%
2040	14.9%	57.8%	120.9%	12.1%
2045	19.9%	84.4%	342.5%	16.1%
2050	25.2%	119.0%	N/A	20.2%

Table 2.5: Total Cost per Therm ($/therm, nominal) — Scenarios 3, 4, 5, 6

Year	Scen 3	Scen 4	Scen 5	Scen 6
2025	$1.2635	$1.2635	$1.2635	$1.2635
2030	$1.9409	$1.9268	$1.8752	$2.6250
2035	$3.1357	$3.5529	$2.8352	$4.2706
2040	$5.0258	$5.2065	$4.4562	$6.2571
2045	$9.9763	$7.3144	$9.9461	$8.6372
2050	$13.6629	$10.0755	N/A	$11.4782

Table 2.6: % Difference in Total $/Therm vs Scenario 0A

Year	Scen 3 vs 0A	Scen 4 vs 0A	Scen 5 vs 0A	Scen 6 vs 0A
2025	0.0%	0.0%	0.0%	0.0%
2030	21.3%	20.4%	17.2%	64.1%
2035	59.3%	80.5%	44.0%	116.9%
2040	111.8%	119.4%	87.8%	163.7%
2045	254.9%	160.2%	253.8%	207.2%
2050	315.5%	206.4%	N/A	249.0%

RNG is too expensive to be a meaningful solution

Table 3.1: RNG Commodity Cost ($/MMBtu) by Scenario

Year	Conventional	Scen 4: 50% RNG	Scen 6: 100%	Scen 3: Hybrid
2030	$5.18	$6.70	$14.94	$6.78
2035	$5.80	$16.74	$27.67	$12.62
2040	$6.50	$24.88	$43.26	$23.38
2045	$7.28	$34.74	$62.19	$62.19
2050	$8.16	$46.61	$85.06	$85.06

Note: Any RNG blending requirement would further increase costs, potentially driving additional electrification and customer attrition.

Table 3.2: % Difference in Real Monthly Bills — Electrification vs RNG Scenarios

Year	Scen 5 vs Scen 6	Scen 4 vs Scen 6	Scen 5 vs Scen 4
2025	0.0%	0.0%	0.0%
2030	-28.6%	-26.6%	-2.7%
2035	-33.6%	-16.8%	-20.2%
2040	-28.8%	-16.8%	-14.4%
2045	15.2%	-15.3%	36.0%
2050	N/A	-12.2%	N/A

Note: Even in an unmanaged electrification scenario, remaining gas customers face lower bill impacts than under RNG or hybrid+RNG approaches.

Table 3.3: Commodity Cost Propane Breakeven Year by Scenario

Scenario	Propane Breakeven
Scen 4: 50% RNG + 50% Elec	2048
Scen 6: 100% RNG	2037
Scen 3: Hybrid Heating + RNG	2042

Hybrid heating that keeps gas in place won't provide a consumer benefit

	Scen 2 Value	Scen 0A Value	Difference
Statement 4.1: Per-therm cost increase (real, 2025-2050). Scen 2 vs Scen 0A. See cols F-H for computed values.	158.5%	47.4%	111.1%

Statement 4.2: Rev Req/Customer increase (real, 2025-2050). Scen 2 vs Scen 0A. See cols F-H for computed values. 63.4% 35.9% 27.4%

Statement 4.3: Real monthly bill % change (2025-2050), Scen 2. See col F for computed value. 20.7%

Managing costs in a climate-aligned transition can save consumers

This section examines the impact of proactive infrastructure planning on consumer costs under climate-aligned scenarios 4 and 5. "Proactive" assumes capital additions follow DTE's GDP plan through 2035, then decline 5%/yr. "Aggressive" assumes capital additions are held flat at 2025 levels through 2035, then decline 5%/yr. All other assumptions (customer trajectories, demand decline, commodity costs) remain identical to the base scenarios.

Table M.1: Capital Additions Trajectory ($M, nominal)

Year	Scen 4	Scen 4_Pro	Scen 4_Agg	Scen 5	Scen 5_Pro	Scen 5_Agg
2025	694.0	694.0	694.0	694.0	694.0	694.0
2030	927.0	927.0	694.0	927.0	927.0	694.0
2035	1,071.0	1,071.0	694.0	1,071.0	1,071.0	694.0
2040	1,071.0	829.0	537.0	1,071.0	829.0	537.0
2045	1,071.0	641.0	416.0	1,071.0	641.0	416.0
2050	1,071.0	496.0	322.0	1,071.0	496.0	322.0
Total	26,363.0	21,219.0	14,711.0	26,363.0	21,219.0	14,711.0

Table M.2: Real Monthly Bills (2025$) — Managed CAPEX Scenarios

Year	Scen 4	4_Pro	4_Agg	Scen 5	5_Pro	5_Agg
2025	$96.18	$96.18	$96.18	$96.18	$96.18	$96.18
2030	$124.49	$124.49	$119.21	$121.15	$121.15	$115.46
2035	$194.84	$194.84	$182.09	$155.48	$155.48	$140.18
2040	$242.35	$238.62	$218.51	$207.43	$202.20	$174.05
2045	$288.98	$275.90	$250.50	$392.96	$361.54	$300.58
2050	$337.88	$310.36	$280.76	*N/A*	*N/A*	*N/A*

Table M.3: Real Revenue Requirement per Customer ($/yr, 2025$) — Managed CAPEX

Year	Scen 4	4_Pro	4_Agg	Scen 5	5_Pro	5_Agg
2025	$732.12	$732.12	$732.12	$732.12	$732.12	$732.12
2030	$974.56	$974.56	$911.25	$1,052.53	$1,052.53	$984.15
2035	$1,236.75	$1,236.75	$1,083.79	$1,484.11	$1,484.11	$1,300.55
2040	$1,518.68	$1,473.91	$1,232.57	$2,126.16	$2,063.48	$1,725.60
2045	$1,820.96	$1,663.90	$1,359.10	$4,370.31	$3,993.36	$3,261.85
2050	$2,178.92	$1,848.68	$1,493.54	*N/A*	*N/A*	*N/A*

Table M.4: Real Total Cost per Therm ($/therm, 2025$) — Managed CAPEX

Year	Scen 4	4_Pro	4_Agg	Scen 5	5_Pro	5_Agg
2025	$1.2600	$1.2600	$1.2600	$1.2600	$1.2600	$1.2600
2030	$1.7200	$1.7200	$1.6500	$1.6700	$1.6700	$1.5900
2035	$2.8300	$2.8300	$2.6500	$2.2600	$2.2600	$2.0400
2040	$3.7000	$3.6400	$3.3400	$3.1700	$3.0900	$2.6600
2045	$4.6400	$4.4300	$4.0200	$6.3100	$5.8100	$4.8300
2050	$5.7100	$5.2400	$4.7400	*N/A*	*N/A*	*N/A*

Table M.5: 2050 Savings from Managed CAPEX vs Base Scenarios (Real 2025$)

Metric	4_Pro vs 4	4_Agg vs 4	5_Pro vs 5	5_Agg vs 5

2050 Rev Req ($M, real)	-328.3	-681.2	*N/A*	*N/A*
2050 Monthly Bill ($, real)	-$27.52	-$57.11	*N/A*	*N/A*
2050 Rev Req/Cust ($/yr, real)	-$330.24	-$685.38	*N/A*	*N/A*
2050 Cost/Therm ($/therm, real)	-$0.4648	-$0.9646	*N/A*	*N/A*
Total CAPEX 2025-2050 ($M)	-5,143.5	-11,652.0	-5,143.5	-11,652.0
2050 Monthly Bill % Savings	8.0%	17.0%	*N/A*	*N/A*

MPSC Case No: U-21973	
Requester: MECCUB	
Question No.: MECCUBDG-5.2b	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: Refer to page 41 of the GDP.

b. Please provide projected mileage of main installations for each year through 2037, broken out by the same categories described in part (a) of this question. Please provide this information in Excel-file format with formulas intact and units and assumptions clearly identified.

Answer: The Gas Renewal Program expects to install 127 miles in 2026 and average 196 miles from 2027 to 2037. The other programs previously broken out do not have mileage forecasts planned out to 2037 as they are more emergent or project dependent, as opposed to being a planned main renewal program such as the GRP.

Attachment: None

Co-Respondent(s): K. M. Fedele

MPSC Case No: U-21973
Requester: Staff
Question No.: STDG-2.13_Supplemental
Respondent: S. Kehoe
Page: 1 of 1

Question: Referring to Page 22, Table 5, of Company witness Scotty N. Kehoe's direct testimony; are the 2025 values provided in Table 5. Historical and Forecasted Pipeline Integrity Expenses, including In-Line Inspections and Direct Assessments full-year 2025 actuals? If not, please provide an update to Table 5 to include full-year 2025 actual values. Additionally, please update Table 5 to include full-year actual values for the calendar years 2023, 2022, 2021, 2020, and 2019.

Answer: DTE Gas objects to this request to the extent that it seeks confidential and/or material non-public information. Without waiving said objection and subject thereto: 2025 actuals are preliminary and unaudited prior to the filing of the Company's SEC Form 10-K.

Year	Number of In Line Inspections and Direct Assessments	O&M Expenses
2019	12	$17.5 M
2020	11	$10.6 M
2021	12	$18.6 M
2022	9	$16.3 M
2023	4	$8.6 M
2024	10	$15.7 M
2025	10	[redacted]
2026	6	$30.0 M
2027	16	$42.0 M

Attachment: None.

Co-Respondent(s): Legal

MPSC Case No: U-21973	
Requester: AG	
Question No.: AGDG-6.221	
Respondent: S. Kehoe	
Page: 1 of 1	

Question: Refer to Table 6 on page 24 of Mr. Kehoe's direct testimony on Pipeline Integrity Expenses. Please show in Excel how the $23.3 million was determined relative to the 2026 and 2027 amounts in Table 5 on page 22.

Answer: The projected test period (12 months ending September 2027) O&M expense for Pipeline Integrity is $39 million. This is a $23.3 million known and measurable change from the Historical Test Period. Please refer to the attachment.

As stated in response CLC-6.1b, a correction is required for the 2027 projected annual spend. The projected spend for 2027 is $42.0M as reflected in the attachment. This does not change the projected test year spend or the known and measurable change amount.

Attachment: U-21973 AGDG-6.221 Pipeline Integrity Known and Measurable

MPSC Case No: U-21973	
Requester: MECCUB	
Question No.: MECCUBDG-5.12a	
Respondent: E. D. Janness	
Page: 1 of 1	

Question: Refer to the following statement on page EDJ-68 of the Direct Testimony of E. D. Janness: "The Company has been replacing legacy regulators addressing overpressure risk annually through its system reliability work, but the current pace of replacement is insufficient to address the large number of aging and outdated regulator asset stations within the distribution system"

a. How many "aging and outdated" regulator asset stations currently exist on DTE's distribution system?

Answer: Currently there are approximately 2,100 legacy regulator stations to be replaced within the Company's distribution system.

Attachment: None

MPSC Case No: U-21973
Requester: MECCUB
Question No.: MECCUBDG-5.12b
Respondent: E. D. Janness
Page: 1 of 1

Question: Refer to the following statement on page EDJ-68 of the Direct Testimony of E. D. Janness: “The Company has been replacing legacy regulators addressing overpressure risk annually through its system reliability work, but the current pace of replacement is insufficient to address the large number of aging and outdated regulator asset stations within the distribution system”

b. What has DTE’s “current pace of replacement” been over the last 10 years?

Answer: The Company has been replacing obsolete district regulators at an average pace of approximately 15 stations per year over the past 7 years. At that pace it would take approximately 140 years to address the current inventory of legacy regulator stations. Legacy regulators may have also been replaced during other work not targeted at obsolete regulators. The average number of total district regulators replaced through System Reliability and GRP is approximately 75 stations per year over the past 7 years.

Attachment: None

Electrification incentives for delivered fuel customers

One of the greatest near-term opportunities available to reduce GHG emissions while also reducing energy bills in residential buildings is through electrification of homes currently heated by delivered fuels, such as propane and fuel oil. Upgrading a home that is heated by an average delivered fuel system to an ASHP and HPWH uses about one-fourth of the energy and reduces GHG emissions by 60% in the first year.[156]

While the majority of homes in Michigan are heated by natural gas, a significant portion of Michigan's residential buildings are heated by delivered fuels. According to the U.S. EIA, Michigan ranks first across the entire country in residential consumption of propane, with 9.1% of homes heated by propane and 0.8% of homes heated by fuel oil in 2023.[157] This amounts to over 400,000 homes in Michigan that are heated by delivered fuels, which on average are disproportionately single family, rural, and older.[158] Additionally, low-income households across the U.S. that are heated by delivered fuels, including fuel oil, kerosene, and propane, overall experience significantly higher energy burden compared to low-income households heated by electricity or natural gas.[159]

Homes across Michigan that are heated by delivered fuels can greatly benefit through efficient electrification. According to an analysis by RMI using the Green Upgrade Calculator, upgrading to heat pumps in homes heated by delivered fuels saves about $660 per year per household in Michigan.[160] Additionally, heat pumps produce no indoor air pollution, while homes heated by poorly maintained delivered fuel systems "can release harmful pollutants into the home, including carbon monoxide, nitrogen dioxide, and volatile organic compounds," which can pose health risks to occupants.[161]

> Upgrading to heat pumps in homes heated by delivered fuels saves about $660 per year per household in Michigan.

To reduce energy bills, GHG emissions, and indoor air pollution, it is critical that the state support policies and funding to encourage adoption of heat pumps in homes heated by delivered fuels. Many of the policies that support residential building electrification for homes heated by natural gas also support homes heated by delivered fuels, including many policies suggested throughout this roadmap, but more can be done to address the needs of delivered fuel customers. Specifically, the creation of a state-funded rebate program to provide incentives for the installation of ASHPs, GSHPs, and HPWH to LMI households using delivered fuels would reduce up-front retrofit costs while resulting in a greater reduction in energy bills compared to households currently heated by natural gas.

Similar programs across the U.S. have been successful in encouraging the replacement of delivered fuels with heat pumps. For example, Seattle's Clean Heat Program offers instant rebates for homes that switch from heating oil to heat pumps, and starting in September 2024, Seattle combined program funding with Washington's HEAR program to offer up to $8,000 per project, depending on household income status.[162] The program has electrified over 1,600 homes, which is on track to meet the City's goal of electrifying all oil-heated homes by 2030.[163] To get the most impact from a state-level delivered fuel electrification incentive program, Michigan EGLE should lead on administering the program, and in a similar fashion to Seattle's program, consider administering the program in a way that also takes advantage of Michigan's HEAR program and other federal and state funded programs that decarbonize homes.

SECTION 5: REGULATING ENERGY EFFICIENCY AND HOME ELECTRIFICATION

Background

In addition to supportive incentives that enable decarbonization measures, a number of legislative and regulatory changes are needed in Michigan to support energy efficiency and electrification. The following sections focus on regulations that should be adopted to reduce barriers to electrification, such as ensuring fairness in rate design and requiring new homes and buildings to be energy efficient and electrified from the start through updated energy codes. While some policies discussed in this section may also have attributes of incentive programs (see Section 4: Incentivizing Energy Efficiency and Home Electrification), policies were organized between sections based on core functionality.

Section 5.1: Improved Rate Design for Electrification

Effective rate design is critical to achieving residential building decarbonization in Michigan because it directly influences consumer decisions about energy use and technology adoption. As homes transition from fossil fuel-based heating systems to electric alternatives like high-efficiency heat pumps and water heaters, such as ccASHPs, GSHPs and HPWHs, rate structures must accurately reflect the costs and benefits of electrification to ensure affordability and encourage adoption. As noted in a fall 2025 report from the Northeast States for Coordinated Air Use Management (NESCAUM), “As electricity gets cleaner, the societal cost of using electricity declines relative to the societal cost of using methane gas. In many states and utility service territories, however, current rate structures create a ‘spark gap’ that sends the opposite price signal to customers.”[180] Without thoughtful rate design, households could face financial disincentives that slow the transition away from gas and other carbon-intensive fuels. For example, high volumetric rates may discourage building electrification by increasing bills for customers who switch to electric technologies.[181] Additionally, equitable and forward-looking rates help utilities plan for system impacts, align infrastructure investments with decarbonization goals, and ensure that the benefits of clean energy technologies are accessible to all customers, including LMI households.

Under Michigan law, the MPSC is required to set electric rates based on the cost-of-service for each customer class, using specified cost allocation methods.[182] If cost-based rates would significantly impact customers, the Commission may phase them in. The MPSC may also establish reduced rates for eligible low-income and senior customers, with utilities required to propose cost-recovery methods in rate filings.[183] Within these statutory constraints, there are rate design options available to the Commission to reduce barriers and seize opportunities around residential building decarbonization, including technology-neutral time-differentiated rates and heat pump-specific rate plans.

> Effective rate design not only ensures revenue adequacy and fairness but also provides price signals that influence customer behavior, supporting policy goals like energy efficiency, load management, and electrification.

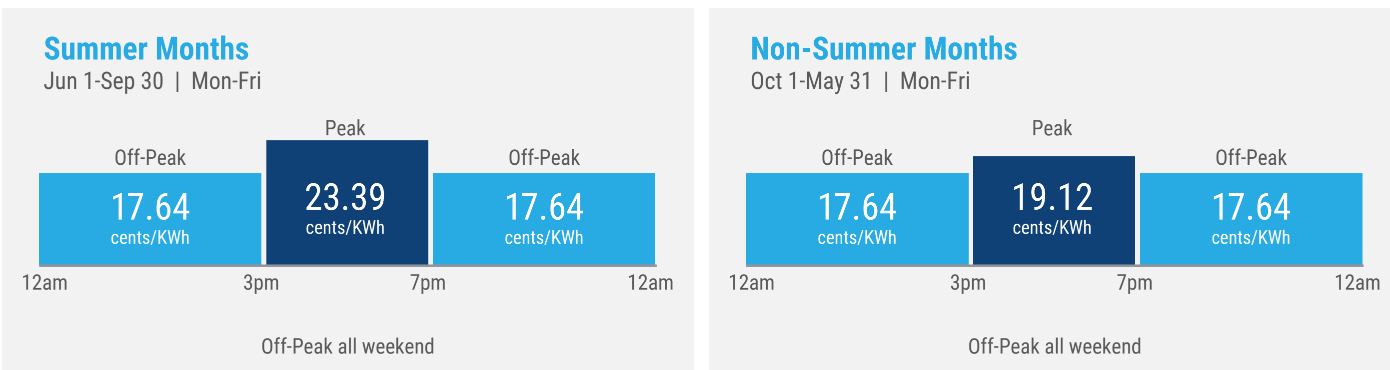
The MPSC could require each utility to conduct a comprehensive analysis of its residential customer base to determine whether it remains appropriate to treat single family and multifamily households as a single rate class, as well as to evaluate customers using electric heating as a distinct class for cost-of-service analysis and rate design. Single family and multifamily households have different energy consumption patterns and cost characteristics and combining them can lead to cross-subsidization and inequitable rate impacts. Similarly, electric heating customers exhibit seasonal usage and winter peak demands that differ significantly from customers using fossil fuel heating. Segmenting these classes would improve cost allocation fairness, support the adoption of energy-efficient and electrification technologies, provide more accurate price signals, and enable the creation of tailored rate structures and demand response programs that enhance affordability, equity, and grid reliability.[184]

Additionally, time-differentiated rates, such as TOU or critical peak pricing, provide more accurate price signals that reflect the true cost of electricity at different times. Even if time-differentiated rates are technology-neutral, they can be effective at promoting more efficient energy use, reducing peak demand, enabling load management, and supporting greater integration of clean energy resources. The MPSC should encourage utilities to develop and offer robust time-differentiated rate structures that more accurately reflect the cost of service for customers using electrified heating, such as heat pumps and electric water heaters. One option, consistent with the alternative electricity tariff design in Section 7.4: Utility Bill Impact Analysis, is to revise the standard residential tariff to include seasonal delivery pricing that benefits customers regardless of whether they change heating fuels.

Evidence from recent MPSC proceedings illustrates that effective rate design hinges on understanding when the grid truly faces its highest costs. For example, in MPSC Case No. U-21684 regarding the 2026 - 2027 EWR Plan of the Upper Peninsula Power Company (UPPCO), in which the utility also voluntarily included an EFEL Measures Plan, 5 Lakes Energy's modeling of transformer loading and system aging showed that the grid experiences its greatest stress in summer, not in winter. As a result, rates should send price signals during summer to reflect these costs, while keeping heating season rates lower to reflect the lower cost causation in the winter. This change in rate design would both align rates with cost causation and make electric heat pumps more attractive for space heating.[185]

By contrast, traditional flat or seasonal rates fail to account for these patterns, potentially leading to cost recovery issues and disincentives for customers considering a transition away from fossil fuel heating. Time-differentiated rates, such as TOU or critical peak pricing, better align customer behavior with grid needs by encouraging energy use during off-peak periods and reducing strain on the system during peak demand hours. According to The Brattle Group, "TOU rates continue to be piloted in North America and internationally; the pilots consistently find that on average customers shift consumption from peak periods to off-peak periods."[186] For example, Consumers Energy piloted its residential Summer Peak Rate in 2019, adopting it statewide in 2021. Under its Summer Peak Rate, on-peak pricing is in effect weekdays from 2 pm to 7 pm from June through September.[187] DTE Energy began rolling out its residential Time of Day rate options on March 1, 2023, establishing a new Time of Day 3pm - 7pm rate.[188] The figure below shows how DTE Energy's Time of Day 3pm - 7pm rate works in the summer months compared to the non-summer months.[189]

Figure 5.1. DTE Time of Day Rate – Summer Months vs. Non-summer Months.[190]



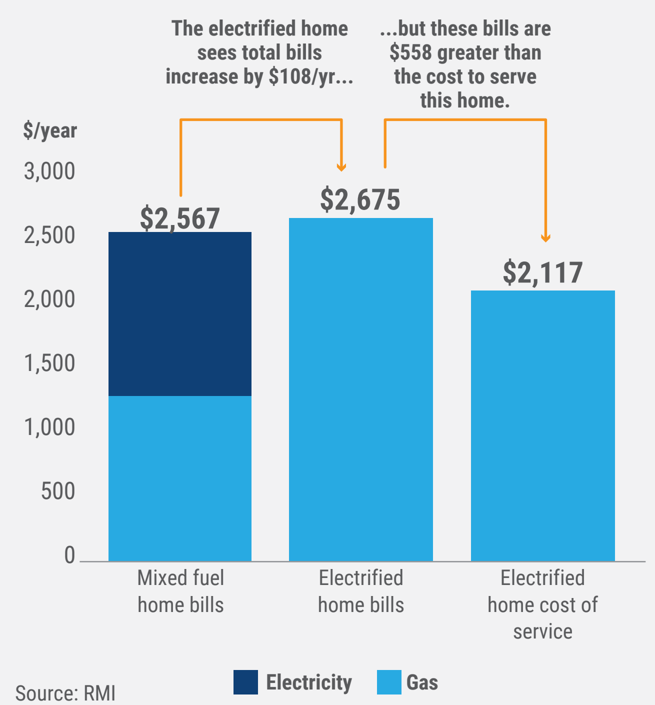
Within TOU rates, the price differential between on-peak and off-peak use is also an important consideration. In its research surveying residential TOU rates across the U.S., The Brattle Group found that, "As the price ratio increases, customers shift usage in greater amounts, but at a declining rate."[191] Further, "[w]hen offered with enabling technology, the effect is stronger."[192] Research from The Regulatory Assistance Project demonstrates this effect: "The price ratio of peak to off-peak tells customers how much they can save. A 2:1 price ratio can be read as a 50% discount in peak pricing to use energy off-peak. A 3:1 ratio can be read as a 66.66% discount from peak pricing."[193] As Michigan utilities seek to refine and tailor their residential TOU rate offerings for customers pursuing electrification, shortening the peak periods and increasing the price ratio based on actual system peak costs are two potential tools for achieving better alignment with cost of service.[194]

While the current Consumers Energy and DTE Energy residential TOU rate options are steps in the right direction, these are generic time-differentiated rate designs developed for average residential use based on summer peak demand, not tailored to the unique load profiles exhibited by users of heat pumps and electrified water heating. As a result, these rate designs likely overcharge customers pursuing electrification measures. A key way to improve on these offerings for customers with heat pumps would be to take into account these customers' higher use during colder months, and during morning and evening hours when heating demand is highest. As emphasized in UPPCO's 2026 - 2027 EWR Plan, by lowering rates in the heating season (October–May) and raising them in summer, customers who switch from propane, fuel oil, or resistance heat to efficient cold-climate heat pumps will see lower operating costs, more accurately reflecting cost causation and strengthening the economics of electrification.[195]

On the whole, homes with heat pumps consume more electricity, especially during off-peak times. Because much of their usage occurs when the grid is under less strain, the cost to serve them differs. A winter discount for heat pump users is "generally based on the cost of service for heat pump customers, without subsidizing other customer classes."[196] The alternative electricity tariff modeled for this roadmap (see Section 7.4: Utility Bill Impact Analysis) confirms that seasonal volumetric delivery charges, (i.e., lower in winter and higher in summer), are consistent with cost causation and can reduce annual bills for most customers who electrify. At the same time, customers who do not fuel switch see no bill increase. This demonstrates that improved electrification-focused rate design can be adopted without shifting costs to non-adopters.

In parallel with the development of new and improved TOU and seasonally time-differentiated rate structures, the MPSC may direct the utilities to correct existing rate structures that currently apply cost-of-service metrics based primarily on summer peak demand, regardless of customers' actual seasonal usage patterns. This one-size-fits-all approach disproportionately penalizes customers who use electricity more heavily in the winter than in the summer, particularly those who have adopted electric heating technologies like ccASHPs. These customers may contribute less to summer peak loads but face higher electricity consumption during colder months, which under current rate designs can lead to unfairly high charges that do not accurately reflect their true impact on system costs.[197] Figure 5.2 below shows how an ineffective rate design based primarily on summer peak demand can overcharge customers who implement home electrification. As shown here, for a Northern Indiana Public Service Company (NIPSCO) customer at the time of the analysis by RMI, the cost to serve the electrified home was only $2,117, but the ineffective rate design over-recovered from the electrified home by charging $2,675, which was $558 more than the cost of service.[198] While this example is based on a single utility, the results are illustrative of the importance of reflecting cost causation in rate design.

Figure 5.2 NIPSCO Electrified Home Bill Comparison.[199]



Source: RMI

Another option is to offer a technology-specific tariff exclusively for electric heating customers, tailored to their unique cost of service and winter-peaking load profiles, which are often characterized by increased electricity consumption during colder months and higher usage during morning and evening hours when heating demand is greatest. Flat-rate plans, on the other hand, should be avoided, as they do not accurately reflect cost of service and tend to increase costs for those using heat pumps.[200]

There are already examples of technology-specific time-differentiated rates in Michigan. For example, DTE Energy currently offers a geothermal TOU rate, tariff sheet D1.7, which is designed to lower electricity costs for customers who install geothermal systems, such as a GSHP. The D1.7 rate provides discounted pricing during off-peak periods, which include 16 weekday hours and all weekend hours, with seasonal adjustments between summer and winter.[201]

Note that in order to participate in DTE Energy's geothermal TOU rate, customers must obtain a second, dedicated geothermal meter. The process begins by submitting a request to DTE Energy's geothermal team and completing a load sheet so the utility can confirm equipment suitability. Customers then hire a licensed electrician to install the necessary wiring for the meter, which is referred to as a D1.7 geothermal advanced meter.[202] Because the additional hassle and cost of installing this second meter may create a disincentive for customers to enroll in the D1.7 rate, and in light of the systemwide benefits of customer adoption of these decarbonization technologies, the MPSC should require utilities to streamline the enrollment and meter installation process and reduce associated costs, ensuring that customers can access the benefits of a geothermal TOU rate (or similar rates) without undue barriers.

As they consider new and improved rate offerings, Michigan utilities can look to examples of heat pump and electric heating rates offered in other states. For instance, the following example heat pump rate is offered by Unitil in Massachusetts, which states: "This new rate class gives customers using heat pumps a reduced distribution rate during the winter months (November to April). You can benefit from this rate if your monthly usage in the winter is higher than the average Standard Residential Rate (R1) customer because you are heating your home with a heat pump. Even if you are only using a heat pump to partially heat your home, you may benefit from being on the Residential Heat Pump Rate."[203] This example aligns with the alternative electricity tariff modeled in Section 7.4 of this roadmap, illustrating how targeted rate design can make electrified heating more cost-effective and appealing for customers while aligning rates with cost causation. The figure below shows Unitil's Heat Pump Rate's reduced per-kWh distribution rate during the winter months compared to the utility's Standard Residential Rate (R1).[204]

Figure 5.3 Heat Pump Rate vs. Standard Residential Rate.[205]

	Residential Heat Pump Rate	(R1) Standard Residential Rate
Customer Charge	$8.50	$8.50
Per kWh Base Distribution Charge	$0.096214 for May 1 to October 31 $0.034354 for November 1 to April 30	$0.09621 all months
Per kWh Supply Charge	$x.xx (same as R1 Rate)	$x.xx

Beyond heat pumps, effective rate design to support electric water heater users is also a key consideration for residential building decarbonization. Water heater rates should support grid-beneficial, cost-effective electrification of water heating through accurate pricing signals.[206] Time-varying rates are a key tool to align customer behavior with grid needs by encouraging water heating during off-peak hours. These rates encourage load shifting and enable water heaters to serve as controllable thermal storage that can help avoid system peaks, integrate variable renewable generation, and reduce system costs.[207] Ideally, electric water heater rate design should be paired with enabling technologies like automated controls and smart appliances, which make it easier for customers to respond to price signals.[208] Thoughtful rate design, paired with enabling technologies, can unlock the full potential of electric water heaters as a flexible, grid-supporting resource in the clean energy transition.

Whether for electric heat pumps or water heaters, getting rate design right not only benefits the customers adopting new technologies, but it also helps manage system reliability and reduce the need for costly infrastructure upgrades by offering lower rates during times when energy demand is low. Recent research shows that "electricity rates, and other price-based policies can provide strong incentives for households to engage in energy-saving behaviors" and "price-based policies may drive long-term impacts in demand-side investments and behaviors much more than previously thought."[209] In other words, there is evidence that price-based policies, such as changes to rate design, can yield significant results, but it takes time to see the full magnitude of the impacts. Over a 30 to 40-year period, consumers are roughly 16 times more responsive to changes to the price signals in their electricity rates than they are from month to month.[210] As a result, as Michigan utilities roll out and refine time-differentiated pricing or special rates for heat pumps and electric water heaters, the full benefits will be increasingly evident in the long run.

To maximize effectiveness, these rates should be easy to understand, supported by clear customer education, and designed to promote long-term savings, particularly for LMI households adopting electric heating solutions.[211] Ensuring transparency and accessibility in rate design helps customers make informed decisions, while targeted outreach and tailored incentives can further enhance affordability and encourage equitable adoption among vulnerable households. In addition, utilities should be required or strongly incentivized to proactively enroll customers in the rate plan that best aligns with their usage patterns, since many households are currently on suboptimal plans and paying more than necessary. This type of active enrollment support will help ensure that customers actually realize the savings and protections envisioned in the rate design.

As electric rate design evolves to better reflect cost causation and support electrification, an equally important challenge lies in aligning gas utility regulation with the realities of a decarbonizing building sector. As explored in the section that follows, rate reforms that send accurate price signals for electric heating and other end uses will only achieve their full potential if gas infrastructure planning also adapts to declining throughput and long-term transition goals.

Section 5.2: Future of Gas Distribution

As states across the country work toward affordability and decarbonization goals, rethinking the role of natural gas in the energy system has become a pressing priority. Reducing reliance on gas pipelines supports decarbonization and is essential for protecting consumers from both volatile fuel prices and increasing infrastructure costs.[212] Although natural gas prices in states like Michigan remain relatively low today, they are historically volatile and are projected to rise in coming years, exposing customers to potential price spikes.[213] At the same time, the costs of maintaining and expanding gas infrastructure continue to climb, also creating upward pressure on utility rates.

Despite a declining trend in new gas customers, and electric heat pumps outselling gas furnaces the last three years in a row,[214] utility spending on new gas infrastructure continues to grow at an unsustainable pace. From 1997 to 2022, nationwide gas distribution investments increased five-fold, even as the customer base grew by just 17 percent.[215] These trends point to a system in a mature lifecycle phase, where continued overinvestment risks burdening ratepayers with long-term costs. Compounding the issue, outdated regulatory frameworks often incentivize gas infrastructure expansion, even as the gas customer base shrinks and cleaner alternatives emerge.[216] Unlike the electric sector, only a handful of states including Colorado, Illinois, New York, Massachusetts, Minnesota, and Washington, require gas utilities to submit long-term plans.[217] As a result, most states, such as Michigan, have limited tools to evaluate the implications of ongoing development and protect consumers from the risks of overinvestment.

Section 8.3: Utility Bill Impact Analysis Results

As described in Section 7.4: Utility Bill Impact Analysis, annual utility bill impacts from converting natural gas or propane space and water heating[372] to all-electric heat pump equipment were computed for the four representative customer types listed in Table 7.4. Moreover, this analysis examined the combined effects of fuel switching under two separate electricity tariffs (Consumers Energy's existing RSP tariff and an alternative tariff designed with a seasonal delivery charge) and two different fuel switching scenarios (conducted with and without a building envelope upgrade). The purpose of this analysis was to demonstrate conditions under which fuel switching can lead to annual bill savings for typical customer types.

Results of this analysis are summarized in Tables 8.8 through 8.11, one for each of the four representative customer types examined. In each table, household annual total electricity and fuel heating costs are reported before and after fuel switching, both under the RSP tariff with and without an envelope upgrade, and under the alternative tariff with and without an envelope upgrade. Note that on-site fuel cost is always zero after fuel switching because fuel use is fully displaced by additional heat pump electricity load. A positive figure in the final column of each table ("Annual Bill Savings") indicates that fuel switching lowers annual energy expenses in that specific case, providing a net benefit to the customer. A negative figure in the final column indicates an increase in annual energy expenses in that specific case, resulting in a net cost to the customer.

For the baseline single family building type using natural gas, Table 8.8 shows that the RSP tariff never delivers annual bill savings after fuel switching, while the alternative tariff yields annual bill savings when an envelope upgrade is also installed.

Table 8.8. Single Family Building Type, Natural Gas Heating Fuel Baseline

Tariff description	Natural gas heating customer			Heat pump customer				Annual bill savings ($)
	Annual electric ($)	Annual natural gas ($)	Total annual ($)	Envelope upgrade	Annual electric ($)	Annual natural gas ($)	Total annual ($)	
Consumer energy RSP	1,306	1,128	2,434	No	3,254	0	3,254	**(820)**
				Yes	2,608	0	2,608	**(174)**
Alternative tariff	1,307	1,128	2,435	No	2,782	0	2,782	**(347)**
				Yes	2,271	0	2,271	**164**

For the baseline single family building type using propane, Table 8.9 shows that both the RSP and alternative tariffs deliver significant annual bill savings after fuel switching even without an envelope upgrade.

Table 8.9. Single Family Building Type, Propane Heating Fuel Baseline

Tariff description	Propane heating customer			Heat pump customer				Annual bill savings ($)
	Annual electric ($)	Annual propane ($)	Total annual ($)	Envelope upgrade	Annual electric ($)	Annual propane ($)	Total annual ($)	
Consumer energy RSP	1,246	2,587	3,833	No	2,637	0	2,637	**1,196**
				Yes	2,349	0	2,349	**1,484**
Alternative tariff	1,238	2,587	3,824	No	2,293	0	2,293	**1,532**
				Yes	2,065	0	2,065	**1,759**

For the baseline multifamily building type using natural gas, Table 8.10 shows that the RSP tariff never delivers annual bill savings after fuel switching, while the alternative tariff yields annual bill savings when an envelope upgrade is also installed.

Table 8.10. Multifamily Building Type, Natural Gas Heating Fuel Baseline

Tariff description	Natural gas heating customer			Heat pump customer				Annual bill savings ($)
	Annual electric ($)	Annual natural gas ($)	Total annual ($)	Envelope upgrade	Annual electric ($)	Annual natural gas ($)	Total annual ($)	
Consumer energy RSP	725	486	1,211	No	1,504	0	1,504	**(293)**
				Yes	1,316	0	1,316	**(105)**
Alternative tariff	721	486	1,207	No	1,320	0	1,320	**(113)**
				Yes	1,176	0	1,176	**31**

For the baseline mobile home building type using propane, Table 8.11 shows that both the RSP and alternative tariffs deliver annual bill savings after fuel switching even without an envelope upgrade.

Table 8.11. Mobile Home Building Type, Propane Heating Fuel Baseline.

Tariff description	Propane heating customer			Heat pump customer				Annual bill savings ($)
	Annual electric ($)	Annual propane ($)	Total annual ($)	Envelope upgrade	Annual electric ($)	Annual propane ($)	Total annual ($)	
Consumer energy RSP	889	1,742	2,631	No	1,774	0	1,774	**857**
				Yes	1,716	0	1,716	**915**
Alternative tariff	873	1,742	2,616	No	1,547	0	1,547	**1,069**
				Yes	1,504	0	1,504	**1,112**

Two common observations can be made across Tables 8.8 through 8.11. First, under either tariff, fuel switching with an envelope upgrade always delivers a lower net annual expense than fuel switching without an envelope upgrade. Second, when comparing both tariff options after fuel switching with the same envelope condition, the alternative tariff always outperforms the RSP tariff. Another observation is that all propane customers examined see a net benefit from fuel switching whereas natural gas customers see a net benefit from fuel switching only with the alternative tariff when an envelope upgrade is installed.

Conceptually, this analysis demonstrates that a seasonal volumetric delivery charge (a main feature of the alternative tariff) yields annual bill savings after fuel switching for all combined effects examined except when natural gas heating customers fuel switch without an envelope upgrade. Based on this promising result, regulators should require electric utility companies to experiment with incorporating seasonal delivery charges into standard tariffs. In addition, regulators could investigate the merits of offering special tariffs to electric heating customers based on their unique year-round cost of service characteristics.

Finally, the positive net benefits reported for propane customer types in this analysis, even with the existing RSP standard electricity tariff, point to delivered fuels customers as an attractive early target market for fuel switching in Michigan.

Section 8.4: Summary of Model Findings and Conclusions

The dual modeling approach using EPS and the Building Inventory Model demonstrates several key findings. To fully decarbonize Michigan's residential sector by 2050, all onsite fuel consumption must be displaced by around 2035 to accommodate the roughly 15-year design life of fuel-burning devices such as furnaces and gas water heaters. This would ensure that any remaining devices reach normal retirement by the state's goal for decarbonization. EPS further shows that the level of investment needed to achieve MI Healthy Climate Plan goals would yield significant GDP, jobs, and public health benefits relative to a business-as-usual pathway.

The Building Inventory Model reveals that Michigan must install about 2.8 million HVAC heat pumps and 2.3 million HPWHs by 2040 to eliminate household on-site fuel consumption by 2050. In addition, building envelope upgrades can minimize the need for new distribution system capacity to handle widespread fuel switching, as total electricity consumed in 2050 in a decarbonization scenario is 6.6% lower with envelope upgrades than without.

Finally, an analysis of annual utility bill savings demonstrates the importance of rate design to accurately reflect the costs to serve customers who electrify their homes while also enabling those customers to reduce their electricity bills. The modeling also found that delivered fuels customers appear to be an attractive early market due to currently higher heating costs for propane and fuel oil relative to natural gas.

Direct utilities to segment residential rate classes.

- *Background:* Single family, multifamily, and electric heating customers have distinct energy use patterns and cost characteristics that are obscured when combined, leading to inequitable cross-subsidization.
- *Recommendations:* Direct utilities to conduct an analysis of whether single family and multifamily residential customers should continue to be grouped within the same rate class, given the differences in usage patterns, load profiles, and cost drivers between these customer segments. In addition, require utilities to evaluate electric heating customers as a distinct subclass for both cost-of-service analysis and rate design purposes. This assessment should consider how seasonal consumption, heating technologies, and peak demand contributions differ from those of non-heating customers, ensuring that rates more accurately reflect cost causation and support equitable, grid-beneficial electrification.

Reform cost allocation practices to prevent overcharging of winter-peaking customers.

- *Background:* Current cost allocation methods, which emphasize summer peak demand, unfairly overcharge winter-peaking customers who adopt electric heating technologies by misaligning rates with their actual system costs. Updating these practices to reflect seasonal and load-profile differences ensures fair cost recovery, removes financial disincentives for electrification, and better supports Michigan's decarbonization goals.
- *Recommendations:* Through individual rate cases or a dedicated regulatory proceeding, revise existing rate designs that place disproportionate emphasis on summer peak demand, resulting in higher costs for customers whose usage peaks in the winter due to electric heating. Such rate structures can inadvertently discourage beneficial electrification and fail to reflect the true drivers of system costs. The revised approach should ensure that rates more accurately represent customers' actual seasonal usage patterns, supporting fair cost recovery while encouraging efficient, year-round system utilization.

Require utilities to implement electric heating rate plans.

- *Background:* Customers with heat pumps have unique seasonal and daily load profiles that are not well-served by generic residential rates, often resulting in higher bills despite the grid benefits that these customers provide. Tailored rates, such as winter discounts and time-of-use structures, align prices with actual costs to serve these customers, improve affordability, and encourage broader adoption of efficient electrification technologies.
- *Recommendations:* Require utilities to develop rate designs specifically tailored to customers using heat pumps, ensuring that these rates reflect the principles of cost causation as well as cost-of-service alignment. Because heat pump users have distinct seasonal usage patterns, with higher electricity consumption during winter months, rates should be structured to capture the actual costs these customers impose on the system while also recognizing the benefits they provide through efficient, year-round operation. Properly designed rates will promote equitable electrification, send accurate price signals, and support fair recovery of system costs across all customer classes.

Require utilities to adopt time-differentiated pricing.

- *Background:* Time-differentiated pricing provides customers with accurate price signals that reflect the true cost of electricity at different times, encouraging more efficient energy use and load shifting to off-peak periods. This approach reduces peak demand, enhances grid reliability, supports integration of clean energy resources, and lowers system costs while enabling customers to save money.
- *Recommendations:* Require utilities to develop and offer TOU or critical peak pricing structures specifically designed for electric heating customers that meaningfully distinguish between summer and winter heating seasons. These rate designs should be grounded in cost-of-service principles and reflect real-time system costs, ensuring that customers pay rates aligned with the actual cost of providing energy at different times of day and year. By promoting off-peak energy use and providing lower rates during periods of low system demand, TOU or critical peak rates can encourage more efficient energy consumption and help balance seasonal load variations. The design should also account for the distinct usage patterns of electric heating customers, including higher overall energy use in colder months and increased demand during morning and evening hours when heating needs are greatest.

Prioritize customer education and transparency in rate structures.

- *Background:* Well-designed rates only achieve their intended impact if customers understand how to respond to price signals and take advantage of cost-saving opportunities. Clear communication and education empower customers, especially low- and moderate-income households, to make informed decisions, maximize long-term savings, and fully participate in the transition to clean, efficient electric technologies.
- *Recommendations:* Ensure that all new rate structures are designed to be easy for customers to understand and supported by clear, accessible education and outreach materials. Utilities should provide resources such as fact sheets, online bill calculators, and personalized rate analysis reports that help customers assess how different rate options affect their bills and energy use. Customer education efforts should highlight opportunities for long-term savings and emphasize accessibility for low- and moderate-income households, ensuring that all customers can make informed choices and benefit from rate designs that promote affordability, transparency, and equitable participation in the clean energy transition. Utilities should be required or strongly incentivized to proactively enroll customers in the rate plan that best aligns with their usage patterns, since many households are currently on suboptimal plans and paying more than necessary.

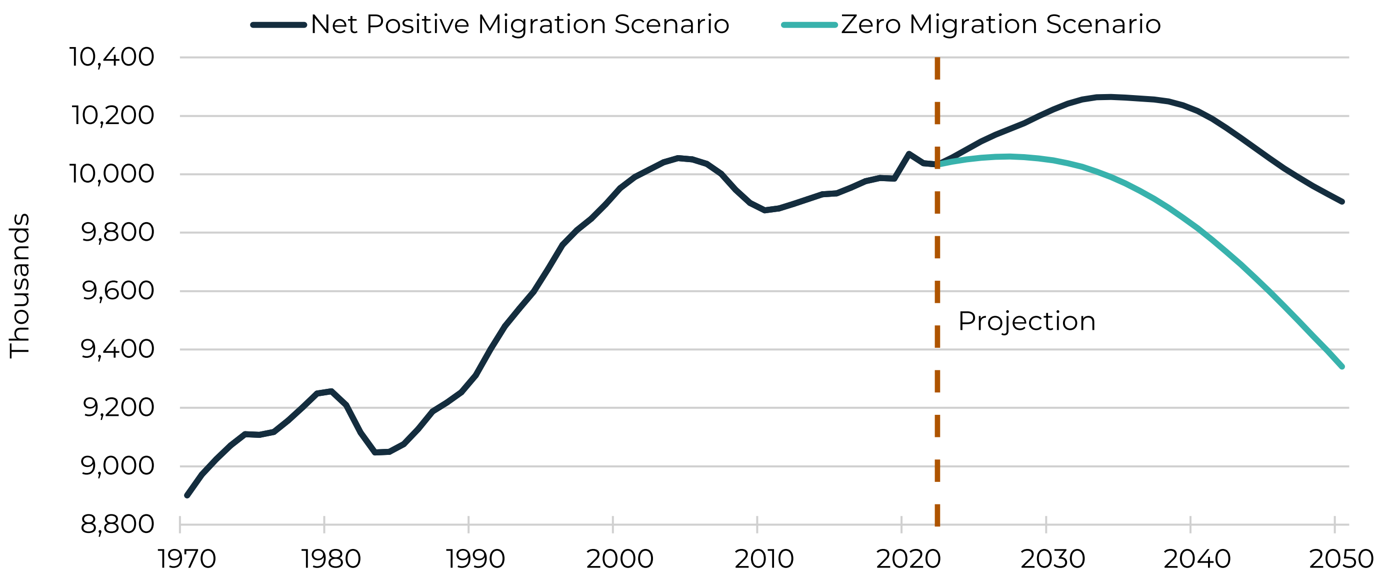
Require utilities to streamline and reduce customer costs related to dedicated meter installation for innovative rates.

- *Background:* The additional hassle and cost of installing a second, dedicated meter may create a disincentive for customers to enroll in DTE's geothermal time-of-day rate (D1.7) or similar innovative rates.
- *Recommendations:* In light of the systemwide benefits of customer adoption of decarbonization technologies, the MPSC should require utilities to streamline the enrollment and meter installation process and reduce associated costs, ensuring that customers can access the benefits of the geothermal time-of-day rate (or similar rates) without undue barriers.

Population Projections

Even with positive migration, Michigan is projected to continue experiencing slow growth and then population decline beginning in the 2030s.

Figure 1: Michigan Total Population, Historical and Projected



Source: WONDER Database, Centers for Disease Control; 2024 Vintage Population Projections, Michigan Center for Data and Analytics; Population Estimates Program, U.S. Census Bureau

Figure 1 displays two potential population trajectories for the state: net positive migration and zero migration. The net positive migration scenario is the main population projection series presented in this report. However, the zero migration scenario provides an illustrative example of what the state's population trajectory would look like with no migration flow. Without net positive migration, the zero migration scenario demonstrates that population decline could occur earlier in Michigan and be more severe through 2050. Specifically, the state population would decline by 692,000 people (-6.9 percent) from 2022 to 2050 with zero migration, compared to a decline of 128,000 (-1.3 percent) with net positive migration.

Michigan has challenging demographic conditions for sustained population growth, even with net positive migration. The state had a pronounced baby boom in the 1950s, followed by a fertility bust and sustained out-migration since the 1970s. These dynamics have contributed to substantial population aging that will continue through 2050. In the past century, Michigan shifted from a young, higher fertility population to an older, low fertility population. Understanding these historical trends is critical to understanding Michigan's current and prospective population trends.

Note: Projected values are based on recent historical trends in the state. Since 2022 is the most recent year of age-specific historical population data available, it serves as the base for the Michigan Center for Data and Analytics 2024 projection vintage. Projected values start at 2023 and continue through 2050.

DTMB Michigan Center for Data and Analytics

Michigan Shows Population Growth and Slight Domestic Gains in 2025

January 27, 2026

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Today the U.S. Census Bureau's Population Estimates Program released new population estimates for the nation and states. This release includes estimates of the population as of July 1, 2025, and is referred to as "Vintage 2025." This release also includes revised annual estimates of the total population each year from 2020 to 2024, as well as revised components of change (births, deaths, and migration).

More information on revisions is available in the Census Bureau's methodology updates for the Vintage 2025 estimates.

Michigan Population Analysis | Labor Market News

Michigan had four consecutive years of growth in the Census Bureau's newest release.

Figure 1. Michigan Total Population, 2010-2025

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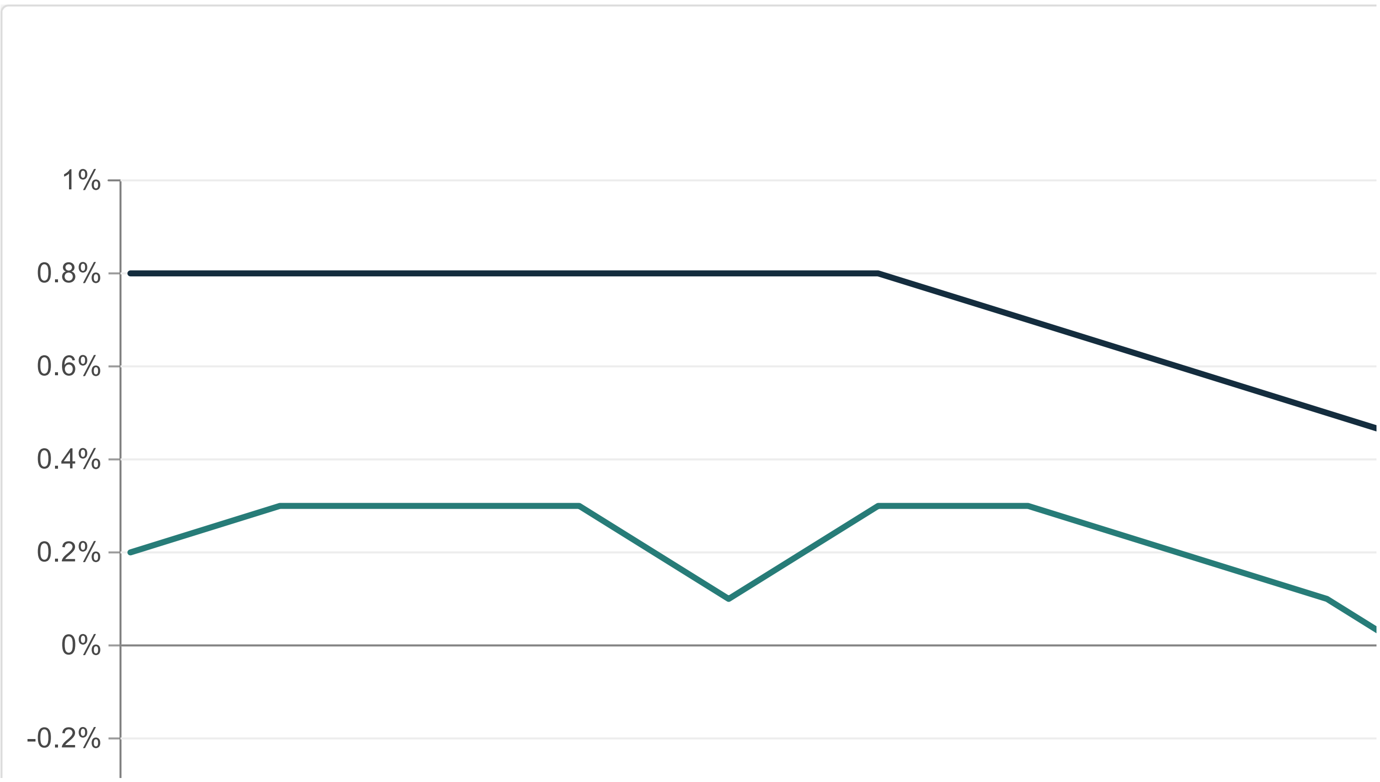
Source: 2010-2020 Intercensal Estimates and Vintage 2025, Population Estimates Program, U.S. Census Bureau

The Census Bureau estimates that Michigan's population was 10,127,884 as of July, 1 2025. This represents an increase of 27,922 people (0.3 percent) from July 2024 to 2025.

The state's population is estimated to have increased by 85,522 people (0.9 percent) over the four-year period from 2021 to 2025.

The U.S. has maintained a higher rate of population growth than Michigan from 2010 to 2025.

Figure 2. Percent Change in Michigan and U.S. Population, 2010-2025



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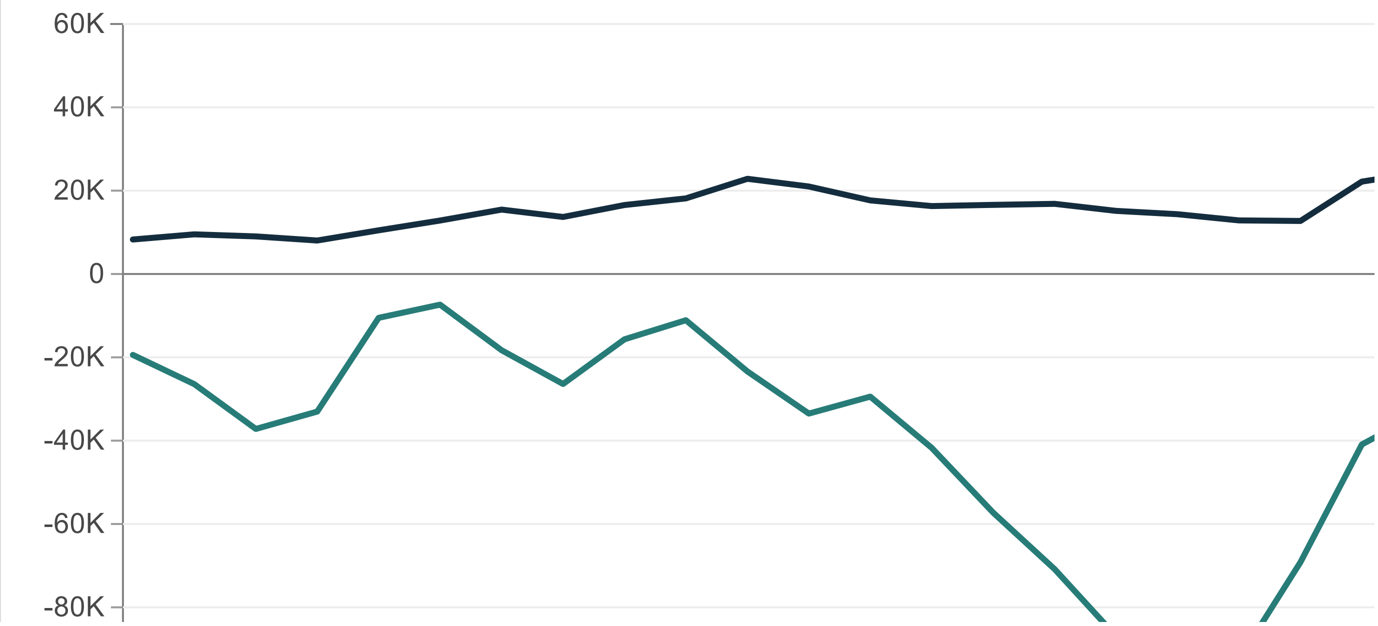
Source: 2010-2020 Intercensal Estimates and Vintage 2025, Population Estimates Program, U.S. Census Bureau

The national population increased by 1,781,060 people (0.5 percent) from 2024 to 2025. Michigan has consistently lagged the nation in population growth from 2010 to 2025.

Michigan ranked 18th among states in numerical growth from 2024 to 2025 and 35th in percent growth.

International migration and small domestic gains from other states contributed to Michigan's estimated increase from 2024 to 2025.

Figure 3. Annual International and Domestic Migration for Michigan, 1991-2025



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Source: Vintage 2000, Vintage 2010, Vintage 2020 and Vintage 2025, Population Estimates Program, U.S. Census Bureau

Michigan's estimated international migration from July 2024 to June 2025 remains high relative to previous decades.

The Census Bureau estimates that Michigan had a net international migration of 30,706 from July 1, 2024 to June 30, 2025. This international estimate is lower than it was the previous year. Overall, however, Michigan's international migration from 2022 through June 2025 remains higher than the 1990s, 2000s, and 2010s.

When compared to the nation, Michigan continues to experience net international migration rates below the U.S. average. Michigan ranks 23rd among states in terms of its net international migration rate from July 2024 to June 2025.

It is important to note that the Congressional Budget Office estimates that **net immigration to the U.S. declined in 2025**. The July 1, 2024-June 30, 2025 estimate period in this release does not reflect changes to international migration patterns that occurred after June 30, 2025.

Michigan shows slight domestic gains from other states in 2025 for the first time in decades.

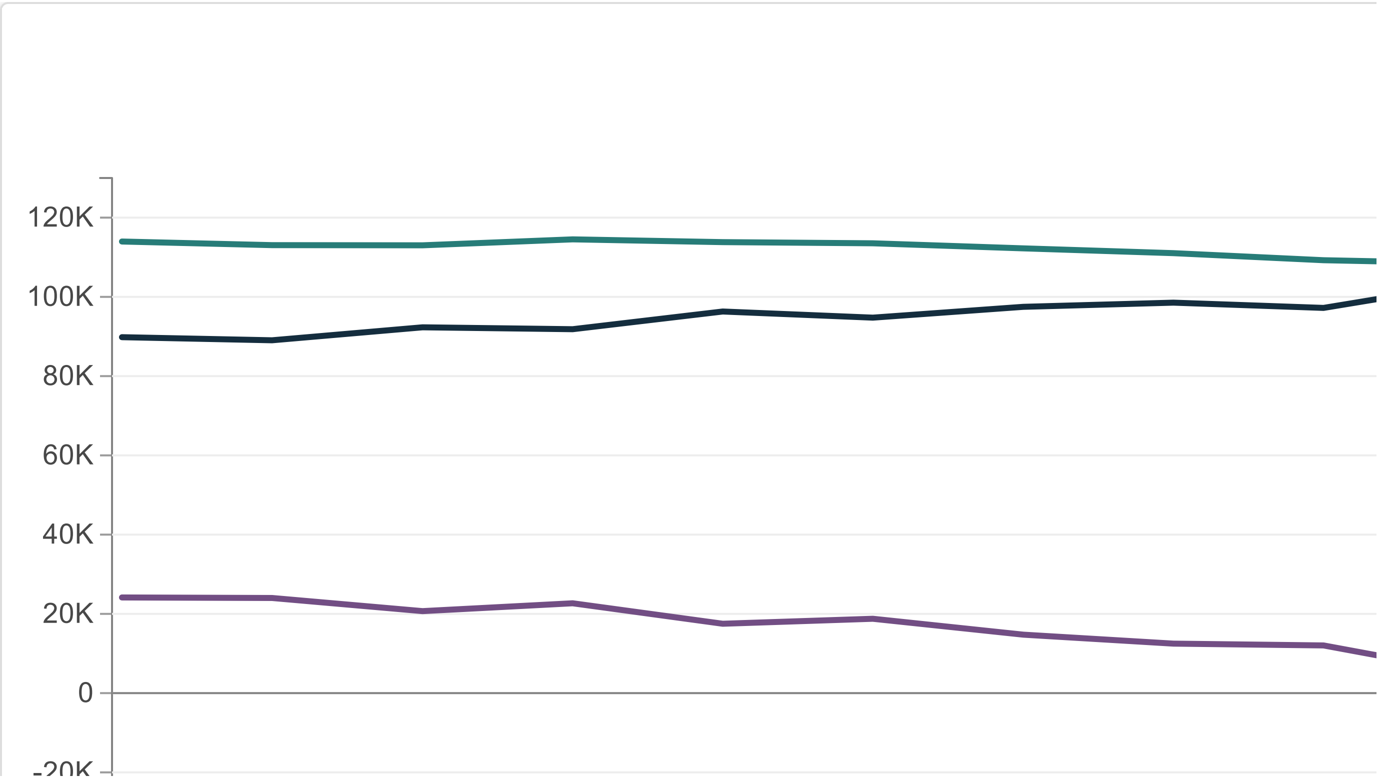
Migration between states is referred to as "domestic migration." The Census Bureau estimates that Michigan had a net domestic migration of 1,796 from July 1, 2024 to June 30, 2025.

Though small, Michigan's net domestic gains in 2025 are notable. This is the first time since at least 1990 that the Census Bureau's Population Estimates Program showed net domestic gains for Michigan. Michigan's annual average net domestic migration for the 2020s so far has improved relative to the 1990s, 2000s, and 2010s.

It is important to note that the net gain of 1,796 in 2025 is very small relative to the overall size of the state's population. Michigan continues to have a relatively low domestic migration rate when accounting for population size. Michigan's domestic migration rate ranked 31st in the nation in 2025.

Michigan experienced its fifth consecutive year of natural decrease (more deaths than births) from July 2024 to June 2025.

Figure 4. Births, Deaths, and Natural Change (Births minus Deaths) in Michigan, 2010-2025



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Source: Vintage 2020 and Vintage 2025, Population Estimates Program, U.S. Census Bureau

Like the migration component, births and deaths are represented in "estimates years," which cover July 1 in the preceding year to June 30 in the following year.

The Census Bureau estimated there were 99,680 births in Michigan from July 2024 to June 2025. This represents a very small increase of 77 births (0.1 percent) from the previous year. Even with this small increase, births remain lower in 2025 than any year in the 2010s.

Michigan had 104,678 deaths from July 2024 to June 2025. This represents an increase of 1,242 (1.2 percent) deaths from the previous year. Deaths remain below the COVID peak in 2022 but higher than any year in the 2010s.

When subtracting deaths from births, Michigan had a natural decrease of 4,998 from July 2024 to June 2025. Michigan is among 17 states that experienced natural decrease for five consecutive years from July 2020 to 2025.

Michigan's natural decrease in 2025 was not as severe as the state's levels of natural decrease in 2021, 2022, and 2023. However, declining births are part of a long-term trend in Michigan. Deaths will continue to increase as a large birth cohort, the baby boomers, age into high mortality years.

Natural decrease will continue placing downward pressure on potential population growth in the state. Potential population growth in the upcoming years is sensitive to consistent and higher levels of migration.

The Census Bureau implemented revisions to the migration components in Vintage 2025.

The Census Bureau adjusts the methodology and data inputs that it uses for its population estimates every year. This can result in revisions to estimates in prior years. The Census Bureau presented **methods changes to the Vintage 2025 release** on January 20, 2026. This presentation provides a full summary of changes to the population components of change (births, deaths, and migration) in Vintage 2025.

The Census Bureau's changes to the international migration estimate resulted in substantial revisions to the state's international migration estimate for 2022, 2023, and 2024. Michigan's international estimate for 2024 was revised from 67,608 in last year's vintage release to 50,486 in this newest vintage release. This represents a downward revision of 17,122 (25.3 percent) for the 2024 international migration estimate.

The Census Bureau's estimate of domestic migration for 2024 also received a downward revision in this newest vintage release. Michigan's domestic migration estimate for 2024 was revised from -7,656 in last year's vintage release to -8,065 in this newest release. This represents a downward revision of 409 (5.3 percent) for the 2024 domestic migration estimate.

Migration is the most challenging population component to estimate. Comparing trends across datasets can help determine if those trends are consistent. Since

MPSC Case No: U-21973	
Requester: MECCUB	
Question No.: MECCUBDG-3.16g	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: Refer to Decker direct, Q&A15, Exhibit A-12 Schedule B5.6 and Case No. U-21291, Order, November 7, 2024, pp. 216-217:

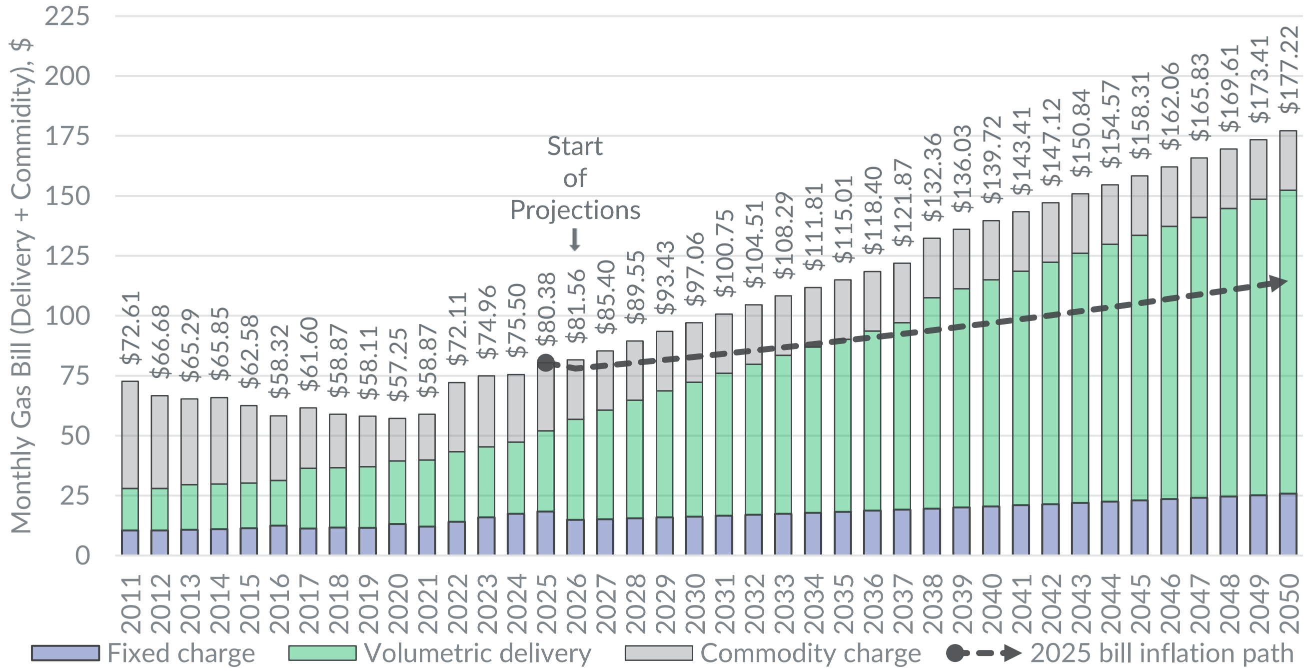
g. Produce the presentation from the April 10, 2025 stakeholder meeting and any notes on that meeting taken by DTE.

Answer: See attached presentation from the April 10, 2025, meeting. DTE Gas does not have any notes taken at the meeting.

Attachment: U-21973 MECCUBDG-3.16g GDP Summary Presentation

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

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



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

4.3 SEMCO

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

Table 4.4: SEMCO Rate Calculation Example (2026)

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

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

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

RNG Production Costs

ICF developed assumptions for the capital expenditures and operational costs for renewable natural gas production from the various feedstock and technology pairings discussed previously. ICF characterizes costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput), gas upgrading and conditioning and upgrading costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnect for pipeline injection. We also include operational costs for each technology type.

ICF presents the costs used in our analysis as well as the levelized cost of energy or LCOE for renewable natural gas in different end uses. The LCOE is a measure of the average net present cost of renewable natural gas production for a facility over its anticipated lifetime. ICF estimates that renewable natural gas can be produced from various feedstocks in a cost range of less than $10/MMBtu to upwards of $50/MMBtu. Anaerobic digestion feedstocks, notably from landfill gas and water resources recovery facilities, tend to be more cost-effective in the short-term future, whereas renewable natural gas from thermal gasification feedstocks is more expensive, largely reflecting the immature state of thermal gasification as a technology, and the associated uncertainties around cost and feedstock availability.

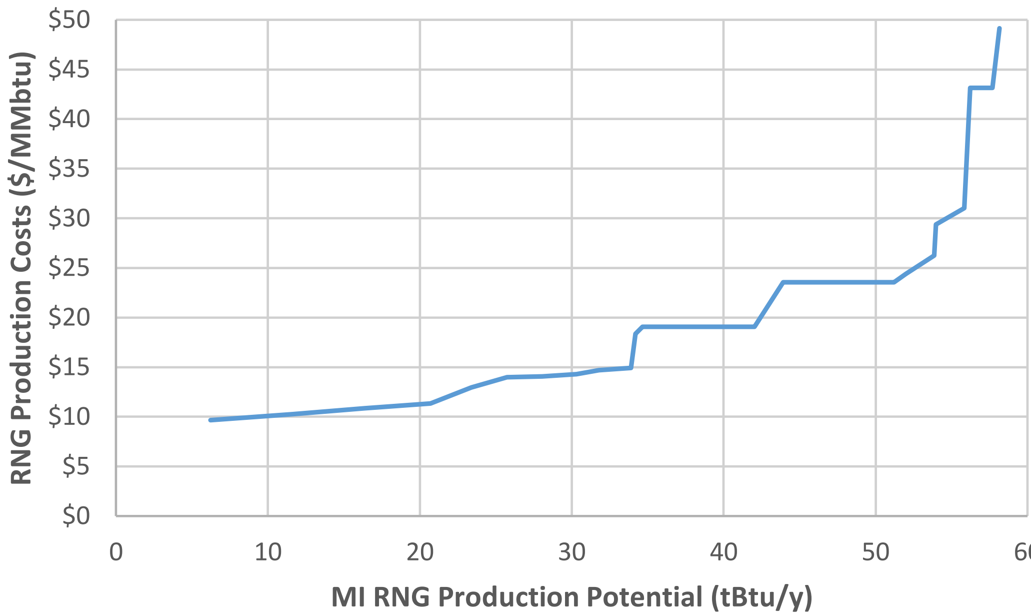
The table below summarizes the range of renewable natural gas production costs, broken down by feedstock. The range for each feedstock reflects variations in considerations associated with scale of individual renewable natural gas production facilities.

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Animal Manure	$14.53 – $49.17
	Food Waste	$18.35 – $29.39
	Landfill Gas	$9.92 – $26.85
	Water Resource Recovery Facilities	$10.90 – $70.86
Thermal Gasification	Agricultural Residues	$19.07 – $43.13
	Energy Crops	$19.07 – $43.13
	Forestry and Forest Residues	$19.07 – $43.13
	Municipal Solid Waste	$19.07 – $43.13

ICF notes that our cost estimates are not intended to replicate a developer's estimate when deploying a renewable natural gas project. Furthermore, these cost estimates do not reflect the potential value of the environmental attributes associated with renewable natural gas, nor the current markets and policies that value these environmental attributes.

The figure below shows the estimated supply-cost curve for renewable natural gas in Michigan in 2050 for the Achievable Scenario (along the x-axis) and the estimated cost to deliver that renewable natural gas (along the y-axis).

Combined Supply-Cost Curve for Michigan in 2050, Achievable ($/MMBtu)



The front end of the supply curve is comprised of landfill gas and water resource recovery facilities. ICF expects the larger thermal gasification systems are expected to be cost competitive in the 2040 to 2050 timeline. The more immediately available opportunities from the anerobic digestion of animal manure and food waste are likely available in the range of middle of the cost range shown in the figure above, whereas the back-end of the supply curve is driven by higher costs of anaerobic digestion at smaller facilities (e.g., farms) and smaller thermal gasification facilities.

Greenhouse Gas Emission Reductions From RNG

When applying a combustion accounting framework for greenhouse gas emissions, ICF estimates that 3 to 8 million metric tons of greenhouse gas emissions could be reduced per year in 2050 in Michigan through the deployment of renewable natural gas based on the Achievable and Feasible scenarios. For the sake of comparison, Michigan's energy-related greenhouse gas emissions were 159 million metric tons of carbon dioxide equivalents in 2019, with about 55 million metric tons attributable to the use of natural gas (or 35% of the total).

It is unlikely that renewable natural gas will be used to displace conventional natural gas in the electric power generation sector because of its higher costs. As such, we focus on the other three main end uses for natural gas: residential, commercial, and industrial. Excluding natural gas used for power generation, the average annual greenhouse gas emissions from natural gas consumption in these three sectors is about 36 million metric tons of greenhouse gas emissions. If RNG was used to displace conventional natural gas in these three sectors, it could decrease emissions from current levels in these sectors from 8% to 22%.

Biogas and RNG: A Market in Transition

Figure 1-1 above illustrates more than just the expansion of the LFGE market; the slowdown in the rate of LFGE project developments in the 2013 timeframe coincided with a significant market shift as it relates to biogas and RNG. LFGE and other biogas-to-electricity projects (e.g., at WRRFs) tend to sell into competitive wholesale electricity markets to generate revenue (also via the sale of renewable energy certificates [RECs] into RPS markets) or for on-site purposes to offset retail power purchases.

The market for biogas started to change in 2014 when the United States (US) Environmental Protection Agency (EPA) determined that RNG qualifies as an eligible renewable fuel for the Renewable Fuel Standard (RFS) program. In 2015, the EPA subsequently determined that RNG sourced from landfills qualifies as a cellulosic biofuel, meeting a GHG emission reduction threshold and cellulosic content requirement, and therefore qualified as a D3 RIN,[16] which ultimately meant that the product delivered more value to eligible RNG consumed in the transportation sector. In other words, the market responded to incentives that favored the upgrading of biogas to make RNG (discussed in more detail below) for pipeline injection, rather than using it to make electricity.

The EPA's determination and associated environmental crediting value led to the rapid expansion of RNG projects for pipeline injection and subsequent RNG use as a transportation fuel in natural gas vehicles (NGVs). As NGVs can be fueled with RNG with no changes to equipment, fueling infrastructure, or vehicle performance, RNG production for use as a transportation fuel has increased nearly six-fold in the last five years. California's Low Carbon Fuel Standard (LCFS) also helped to contribute to expanding the RNG market, with a focus on lifecycle GHG emission reductions, the program provides a premium on the lowest-emitting fuel via a carbon intensity determination, which is a measure of GHG emissions per unit of energy (reported in units of grams of carbon dioxide equivalents per megajoule, gCO_2e/MJ).[17]

This market transition of biogas-to-electricity projects to RNG for transportation is exemplified by the aforementioned Riverview landfill, Michigan's oldest LFGE project. In February 2022, the City of Riverview's City Council voted to approve a modification to the contract with Riverview Energy Systems (RES) that operates the LFGE facility, and it will now produce RNG for pipeline injection and use as a transportation fuel instead of electricity.[18] There are five other operational RNG projects at landfills in Michigan, with a sixth slated to be operational in early 2023.[19] The other market trend is an increased deployment of anaerobic digesters at dairy farms to capture methane from animal manure. For instance, there are four operational dairy digesters in Michigan that produce RNG, and at least another three that have broken ground and will be fully operational towards the end of 2022.

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[16] Renewable Identification Numbers (RINs) are the currency of the RFS program, and are discussed in more detail in the body of the report.
[17] Based on the accounting framework in place for the LCFS program, RNG derived from the anaerobic digestion of animal manure yields more value than RNG from landfill gas.
[18] Based on information reported online at https://www.thenewsherald.com/2022/02/05/project-that-converts-landfill-gas-into-natural-gas-will-benefit-riverview/ on February 5, 2022.
[19] Based on data from the Landfill Methane Outreach Program at the U.S. EPA (updated March 2022).

As of 2021, about 60-65% of the natural gas used in transportation is now RNG because of these markets. ICF anticipates that the market for RNG in the transportation sector will be saturated in the next 2-4 years. And over that same timeframe, the next transition for RNG will continue: The increased demand for RNG in non-transportation markets. The mix of regulatory and voluntary decarbonization commitments by corporate stakeholders, gas utilities, and other key actors have helped to grow the demand for RNG over the last several years, and this increase in demand to date is modest compared to the ultimate potential; however, there are barriers to expanded deployment that may constrain the RNG market.

Study Objective and Study Overview

The objective of this study is to provide data and the accompanying analysis regarding RNG production potential in Michigan that can help to inform policymakers and decisionmakers. The core components of the study include the following:

- Section 2 RNG Production. ICF provides an overview of RNG production and the production technologies that were included in ICF's analysis.
- Section 3 RNG Feedstock Inventory. ICF developed a bottom-up inventory of the various feedstocks in Michigan that can be used to make RNG, including landfills, water resource recovery facilities (WRRFs), food waste, municipal solid waste (MSW), animal manure, energy crops, agricultural residue, and forestry and forest residue products.
- Section 4 RNG Supply Scenarios. ICF used the feedstock inventory to develop RNG production potential estimates consistent with the characteristics of three scenarios: theoretical, feasible, and achievable. These scenarios reflect a variety of constraints regarding accessibility to feedstocks, the time that it would take to deploy projects, the development of technology that would be required to achieve higher levels of RNG production, and the consideration of likely project economics—with the assumption that the most economic projects will come online first.
- Section 5 RNG Production Cost Assessment. ICF developed an RNG supply-cost curve, based on assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology combinations.
- Section 6 GHG Emission Reductions and Cost-Effectiveness. For each RNG production potential scenario quantified, ICF quantified the corresponding GHG emission reductions. ICF used these GHG emission reduction potentials and the production costs to determine the GHG cost-effectiveness of RNG production, in a dollar per ton of CO_2 equivalent metric. ICF also provided a first order comparison to alternatives including blending renewable hydrogen, building electrification, transportation electrification, and renewable electricity generation (inclusive of nuclear electricity generation).
- Section 7 GHG Abatement Cost Comparison. ICF compares the GHG cost-effectiveness of RNG deployment in Michigan to other GHG abatement strategies, including renewable hydrogen blending, building electrification, renewable electricity production, and transportation electrification.
- Section 8 Opportunities and Barriers to RNG Production in Michigan. In this section, ICF reviews the technical, market, and regulatory drivers for RNG, how they are linked, and the key opportunities and challenges across these three broad areas.

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-1.6	
Respondent: S. Kehoe	
Page: 1 of 1	

Question: Please indicate the percentage of system leaks that have been remediated since 2011 that would not have been remediated if not for the Company's greenhouse gas emissions reduction targets.

Answer: None. DTE Gas does not separate leak repairs by public safety and environmental impact. All natural gas leaks are graded to evaluate their severity and the requirements for remediation or monitoring. Leak repairs are prioritized based on their grade. Please see pages 41-44 and page 82 of U-21973 Exhibit B5.6 Schedule A-12 for a discussion of distribution leaks and climate goals.

Attachment: None

Name of Respondent	This Report Is:	Date of Report	Year of Report
DTE Gas Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/04/2025	2024/Q4

625-A. SALES DATA FOR THE YEAR
(For the State of Michigan)

Line No.	Class of Service (a)	Average Number of Customers per Month (a)	Gas Sold Mcf* (c)	Revenue (Show to nearest dollar) (d)	AVERAGES Mcf* per Customer (e)	Revenue per Customer (f)	Revenue per Mcf* (g)
1	AB. Residential Service						
2	A. Residential Service	17,510	989,060	$ 11,819,300	56.49	$ 675.00	$ 11.95
3	B. Residential space heating service	1,145,935	93,368,632	$ 986,854,066	81.48	$ 861.18	$ 10.57
4	CD. Commercial Service						
5	C. Commercial service, except space heating	3,878	1,411,659	$ 14,429,475	364.02	$ 3,720.85	$ 10.22
6	D. Commercial space heating	75,651	26,172,088	$ 269,206,380	345.96	$ 3,558.53	$ 10.29
7	E. Industrial service	347	607,434	$ 5,379,852	1,750.53	$ 15,503.90	$ 8.86
8	F. Public street & highway lighting						
9	G. Other sales to public authorities						
10	H. Interdepartmental sales/Gas Cutomer Choice Revenue (1)		7,183	$ 51,319			$ 7.14
11	I. Other sales						
12	A-I. Total sales to ultimate customers	1,243,321	122,556,056	$ 1,287,740,392	98.57	$ 1,035.73	$ 10.51
13	J. Sales to other gas utilities for resale						
14	A-J. TOTAL SALES OF GAS	1,243,321	122,556,056	$ 1,287,740,392	98.57	$ 1,035.73	$ 10.51
15	K. Other gas revenues			$ 493,562,382			
16	A-K. TOTAL GAS OPERATING REVENUE			$ 1,781,302,774			

* Report Mcf on a pressure base of 14.65 psia dry and a temperature of 60°F. Give two decimals.

1. Gas Customer Choice revenue and volumes associated with reconciliation.

Name of Respondent	This Report Is:	Date of Report	Year of Report
DTE Gas Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/04/2025	2024/Q4

625-B. CUSTOMER CHOICE SALES DATA BY RATE SCHEDULES

1. Report below the distribution of customers, sales and revenue for the year by individual rate schedules. (See definition on first page of this section).
2. Column (a) - List all the rate schedules by identification number or symbol. Where the same rate schedule designation applies to different rates in different zones, cities or districts, list separately data for each such area in which the schedule is available.
3. Column (b) - Give the type of service to which the rate schedule is applicable, i.e. cooking, space heating, commercial heating, commercial cooking, etc.
4. Column (c) - Using the classification shown in Schedule 625-A, column (a), indicate the class or classes of customers served under each rate schedule, e.g., (A) for Residential Service, (B) Heating Service, etc.
5. Column (d) - Give the average number of customers billed under each rate schedule during the year. The total of this column will approximate the total number of ultimate customers, line 12, Schedule 625-A.
6. Columns (e) and (f) - For each rate schedule listed, enter the total number of Mcf sold to, and revenues received from customers billed under that rate schedule. The totals of these columns should equal the totals shown on line 12, Schedule 625-A. If the utility sells gas to ultimate customers under special contracts, the totals for such sales should be entered on a line on this page in order to make the totals of columns (e) and (f) check with those entered on line 12, Schedule 625-A.
7. When a rate schedule was not in effect during the entire year, indicate in a footnote the period in which it was effective.

Line No.	Rate Schedule Designation (a)	Type of Service to which Schedule is applicable (b)	Class of Service (c)	Average Number of Customers per Month (d)	Mcf sold (e)	Revenue (Show to nearest dollar (f)
1	Rate A & AS	Res & Res Heat	A & B	80,036	6,228,817	$35,764,392
2	Rate 2A	Res & Res Heat	A & B	1,216	768,376	$3,616,500
3	Rate GS-1	Comm, Comm Ht & Indust	C, D & E	10,664	6,660,649	$30,912,926
4	Rate GS-2	Comm, Comm Ht & Indust	C, D & E	12	169,657	$627,914
5	Rate S	Comm Ht - Schools	D	80	612,602	$1,908,557
6						
7	Program Year end reconciliation				(7,183)	
8						
9	Energy Waste Reduction					$5,748,498
10	RDM Surcharges					$(591,234)
11	BIO Green/VHWHF Surcharge					$18
12	IRM (Infrastructure Recovery Mechanism)					$5,661,208
13	Reservation Charge					$3,158,005
14						
15						
16						
17						
18						
19	TOTALS			92,008	14,432,918	$86,806,784

atmosphere

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Article

The Michigan–Ontario Ozone Source Experiment (MOOSE): An Overview

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Abstract: The Michigan–Ontario Ozone Source Experiment (MOOSE) is an international air quality field study that took place at the US–Canada Border region in the ozone seasons of 2021 and 2022. MOOSE addressed binational air quality issues stemming from lake breeze phenomena and transboundary transport, as well as local emissions in southeast Michigan and southern Ontario. State-of-the-art scientific techniques applied during MOOSE included the use of multiple advanced mobile laboratories equipped with real-time instrumentation; high-resolution meteorological and air quality models at regional, urban, and neighborhood scales; daily real-time meteorological and air quality forecasts; ground-based and airborne remote sensing; instrumented Unmanned Aerial Vehicles (UAVs); isotopic measurements of reactive nitrogen species; chemical fingerprinting; and fine-scale inverse modeling of emission sources. Major results include characterization of southeast Michigan as VOC-limited for local ozone formation; discovery of significant and unaccounted formaldehyde emissions from industrial sources; quantification of methane emissions from landfills and leaking natural gas pipelines; evaluation of solvent emission impacts on local and regional ozone; characterization of the sources of reactive nitrogen and $PM_{2.5}$; and improvements to modeling practices for meteorological, receptor, and chemical transport models.

Keywords: ozone; air quality; field studies; methane; formaldehyde; ozone; atmospheric chemistry; lake breezes; transboundary transport; emissions inventories; fine particulate matter ($PM_{2.5}$); volatile organic compounds (VOC); nitrogen oxides (NO_x); reactive nitrogen reservoirs

check for updates

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1. Introduction

In 2015, the United States (US) Environmental Protection Agency (USEPA, Washington, DC, USA) set the US National Ambient Air Quality Standard (NAAQS) for ozone (O_3) at 70 parts per billion by volume (ppb) averaged over 8 h [1]. Attainment of the standard is based on an O_3 design value, defined as the three-year average of the annual fourth highest daily 8 h O_3 maximum concentration measured at a monitoring station. Areas with design values that exceed the NAAQS may be designated by the USEPA as in nonattainment of the O_3 standard within several categories of increasing seriousness ranging from marginal to severe, with corresponding increases in mandatory offsets of new emissions of ozone precursors and progressive reductions of existing emissions, as well as other regulatory emissions of ozone precursors and progressive reductions of existing emissions, as well as other regulatory requirements. The federal government of Canada has an even more stringent Canadian Ambient Air Quality Standard (CAAQS) for O_3 of 62 ppb averaged over 8 h, which will be reduced to 60 ppb in 2025 [2]. The statistical form of the Canadian standard is equivalent to that of the US design value.

The Michigan–Ontario Ozone Source Experiment (MOOSE), which took place during 2021 and 2022, was the result of conversations initiated by the Michigan Department of Environment, Great Lakes, and Energy (EGLE) with Environment and Climate Change Canada (ECCC) and the Province of Ontario's Ministry of the Environment, Conservation, and Parks (MECP). In 2007, the Canadian agencies conducted the Border Air Quality and Meteorology Study (BAQS-Met) [3], which revealed the importance of lake breeze phenomena in modulating high O_3 episodes in the southern Great Lakes region (Figure 1). A key discovery of the BAQS-Met study was the enhancement of regional O_3 peaks over the Great Lakes by up to 30 ppb due to lake breeze effects that transported ozone precursors from urban areas and increased their ozone production over water. The pool of high ozone was then available to be transported back to land areas by the lake breeze cycle [3].

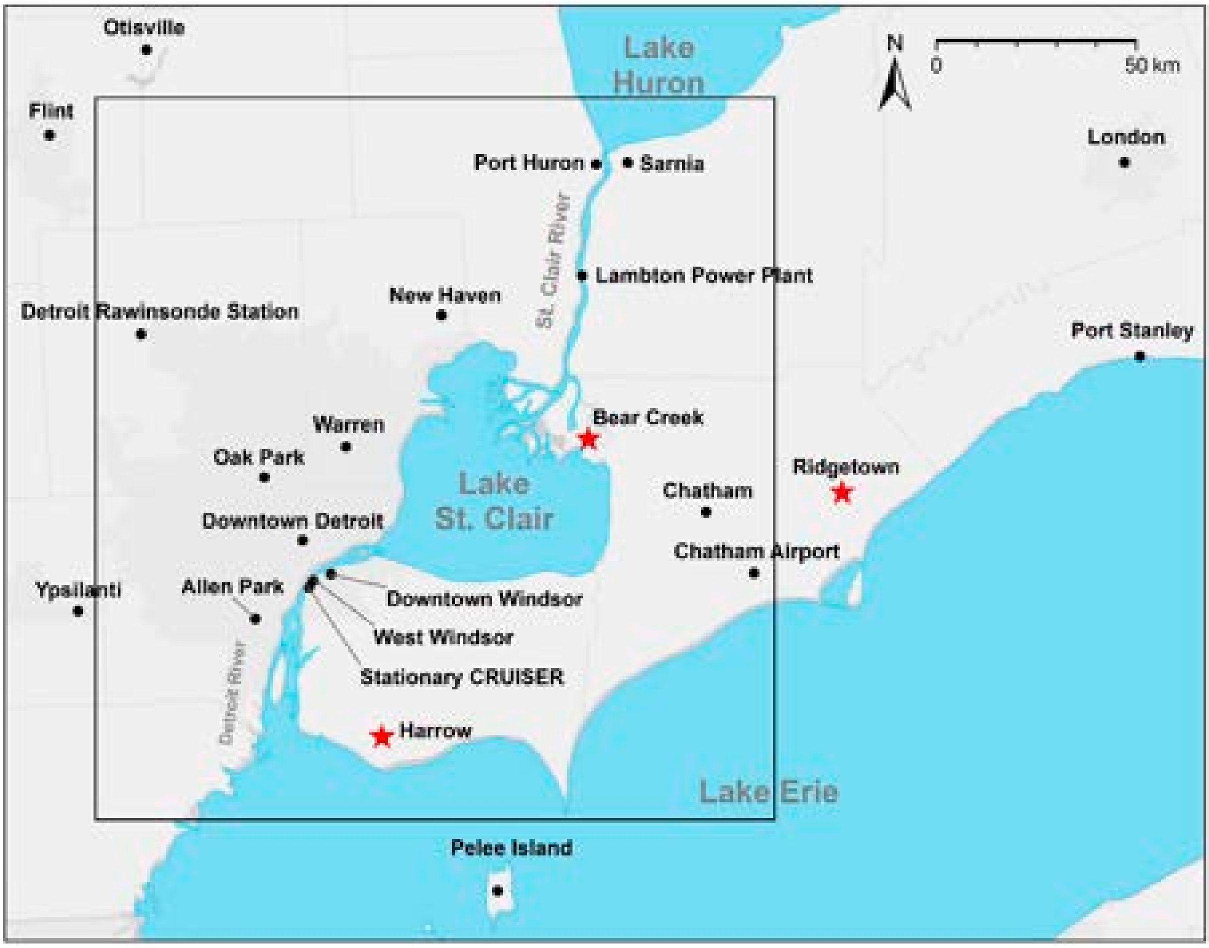

Figure 1. Map of the southern Great Lakes area showing the locations of the major cities in the region and all participating ozone monitoring sites (supersites indicated by red stars) during the BAQS-Met study [3] (modified reproduction licenced under Creative Commons CC BY 3.0). The approximate area that was the subject of the MOOSE field campaign is indicated by the black rectangle.

MOOSE was designed to further address US–Canada Border air quality issues, such as the possibility that southeast Michigan (SEMI), which includes the city of Detroit, would be "bumped up" from its original designation by the USEPA as a marginal O_3 nonattainment area to a moderate nonattainment area with more stringent emissions control requirements. This bump-up occurred very briefly in 2023, until an exceptional event demonstration by

EGLE attributing two days of high O_3 values in June 2022 to a Canadian wildfire was accepted and approved by the USEPA. This enabled SEMI to be re-designated back to attainment of the O_3 NAAQS based on a clean data determination for the three-year period of 2020–2022, as opposed to O_3 design values for 2018–2020 that were the basis for the prior bump-up. However, SEMI remains an ozone maintenance area subject to contingency provisions that would require EGLE to implement new control strategies once a certain ozone concentration threshold has been passed. By providing information on which ozone precursors contribute most to exceedances of the NAAQS, the results of the MOOSE study will help inform the design of new control strategies that may be needed to maintain the current attainment designation for SEMI, as well as to decrease population exposure to other criteria pollutants and to air toxics.

Ozone, fine particulate matter ($PM_{2.5}$), and their precursors are generated both locally and regionally. They can travel hundreds of kilometers, affecting areas far from the emission sources. Long-range transport and transboundary flow of air pollutants play a significant role in Ontario's air quality. During the summer, elevated levels of air pollutants are often associated with distinct weather patterns (i.e., slow-moving high-pressure systems originating from south of the lower Great Lakes) that result in the long-range transport of these pollutants into Ontario from neighboring US industrial and urbanized states during south to southwesterly flow conditions [4].

The Ontario MECP routinely monitors conventional air pollutants, including O_3 and $PM_{2.5}$, at 38 Air Quality Health Index air monitoring stations across the province, including Windsor and Sarnia at the US–Canada Border. Southern Ontario continues to experience persistent elevated ozone levels. In 2020, 13 of the 26 designated CAAQS air monitoring stations exceeded the federal O_3 standard. The provincial Ambient Air Quality Criteria (AAQC) for O_3 (80 ppb averaged over 1 h) was also exceeded several times across southern Ontario in 2020. In southwestern Ontario, when ozone levels are elevated, over 95% of the ozone is attributable to transboundary sources, with the US contributing as much as 40% and the remainder due to the global background [5]. Windsor is the southernmost major city in Ontario and often experiences poor air quality owing to industrial and traffic emissions and transboundary transport of air pollution from neighboring states in the US. The city reported one of the highest $PM_{2.5}$ values in 2020 (i.e., 19 $\mu g/m^3$ for the 24 h CAAQS metric and 7.8 $\mu g/m^3$ for the annual metric) among the 26 designated CAAQS stations in Ontario [5]. Furthermore, Ontario's 24 h AAQC for $PM_{2.5}$ (27 $\mu g/m^3$) was exceeded in Windsor in 2020, although both the ambient levels of $PM_{2.5}$ and its primary emissions to air have decreased over the past 10 years [5].

MOOSE became a reality once EGLE secured funding from the USEPA for the operation of two advanced mobile laboratories to investigate both air toxics and ozone issues in SEMI in a focused study known as the Chemical Source Signatures Experiment (CHESS), which eventually became a sub-experiment of the larger MOOSE campaign (see below). After initial funding was secured by EGLE, both ECCC and MECP committed to adding significant resources to MOOSE, as did federal agencies in the US in addition to the USEPA, including the National Aeronautics and Space Administration (NASA), the US Forest Service, and the National Science Foundation (NSF). MOOSE thus became an international air quality field experiment conducted by federal, state, and provincial governments on both sides of the US–Canada Border.

An Executive Committee was set up with ECCC serving as the official convenor. All official exchanges of the Committee were at the government-to-government level, although contractors hired by a government agency could contribute to deliberations. An early action of the Executive Committee was to develop a Science Plan [6] to guide the deployment of technical resources and define the scientific objectives of MOOSE.

According to the Science Plan, MOOSE would consist of three sub-experiments with the following objectives:

Great Lakes Meteorology and Ozone Recirculation (GLAMOR)

- To understand and successfully simulate complex 3D flows associated with lake breeze circulations;
- To understand and successfully simulate the urban heat island (UHI) and its interaction with the lake breeze;
- To understand and successfully simulate the impact of lake breezes and the UHI on ozone and ozone precursor transport;
- To determine the conceptual picture (mesoscale meteorological patterns and photochemical production locations) for ozone exceedances in the Border region;
- To select representative ozone episodes for each identified mesoscale pattern, which can then be used as model base case periods for future ozone attainment demonstrations;
- To conduct modeling and data analyses in support of an ozone attainment demonstration for SEMI or, if warranted, a US Clean Air Act 179B(b) petition or ozone exceptional event demonstration.

Chemical Source Signatures (CHESS)

- To characterize the ozone precursor signatures at key monitoring stations in the Border region where design values are highest during ozone exceedances in a normal year;
- To characterize emission plumes from point sources in the Border region and their impacts on ozone design values on both sides of the U.S.–Canada Border;
- To develop emission source fingerprints for the most important industrial facilities and source sectors in the Border region;
- To characterize the horizontal variations (including upwind, interior, and downwind concentrations) and vertical gradients of nitrogen oxides (NO_x) and volatile organic compounds (VOCs) in the Border region;
- To perform receptor modeling, source apportionment, and ozone culpability analyses to improve emission inventories and inform potential control strategies;
- To perform air quality model simulations of potential emission control strategies.

Methane Releases from Landfills and Gas Lines (MERLIN)

- To determine the natural gas leakage rate of pipeline or other infrastructure in SEMI;
- To quantify methane, formaldehyde, and other emissions from landfills in the Border region;
- To determine the contributions of large methane sources to ozone exceedances in the Border region, thereby informing potential control strategies.

2. Experimental Methods

With USEPA funding, EGLE hired Aerodyne Research, Inc. (Billerica, MA, USA) and the University of Michigan (Ann Arbor, MI, USA) to conduct mobile laboratory investigations in SEMI during MOOSE. Prior to the execution of the intensive portion of the field study in the late spring and summer of 2021, EGLE developed a Quality Assurance Project Plan (QAPP) for the CHESS experiment that was approved by the USEPA [7]. USEPA-approved QAPPs are acceptable benchmarks of quality for state regulatory agencies in the US.

The Aerodyne Mobile Laboratory (AML) [8–10] measured O_3 (2BTech), total NO_x (cavity-attenuated phase shift spectrometer coupled to an ozone reactor—Aerodyne CAPS-NO_x); nitric oxide (NO) and nitrogen dioxide (NO_2), methane, ethane, formaldehyde, and CO (4 separate tunable infrared laser direct absorption spectrometers—Aerodyne TILDAS [11–13]); CO_2 (non-dispersive infrared spectrometry); and VOCs (gas chromatography electron impact mass spectrometer—Aerodyne GC-EI-ToF [14] and Aerodyne Vocus proton transfer reaction—mass spectrometer [15,16]). The Michigan Pollution Assessment Laboratory (MPAL) [17,18] run by the University of Michigan deployed cavity ring-down spectrometers (Picarro G2401 and G2204) to measure methane, CO, and CO_2, as well as other instruments to measure O_3 (API 400A) and NO_x (EcoPhysics CLD 700 AL). Both the AML and MPAL were equipped with a global positioning system (GPS) and meteorological sensors to measure wind speed and direction, surface pressure, temperature, and relative humidity.

MECP also deployed a mobile monitoring platform equipped with GPS and real-time instrumentation for the measurements of O_3, SO_2, NO_x, particulate matter, and VOCs [19]. Specifically, a proton transfer reaction-mass spectrometer (IONICON PTR-ToF-MS 8000) measured aromatics including benzene, toluene, and xylenes, in addition to other VOCs with proton affinities greater than that of water. The platform was used in summer 2021 to measure air pollutant concentrations and chemical fingerprints immediately downwind of industrial sources in Sarnia and Windsor, Ontario.

Mobile measurements were complemented by measurements at monitoring stations in SEMI and Windsor, Ontario during the 2021 intensive portion of the MOOSE study. In SEMI, these included continuous column measurements of formaldehyde and NO_2 by two Pandora UV-visible spectrometers [13,20] operated jointly by USEPA and NASA, specialized isotopic measurements of reactive nitrogen compounds by a university team funded by NSF (as described in Section 3.1), and continuous measurements of boundary layer wind profiles (mini sodar) and mixing height (ceilometer) by the US Forest Service. These were in addition to routine meteorological and chemical measurements by EGLE at regulatory monitoring stations.

In collaboration with ECCC, MECP enhanced air monitoring activities at its Windsor West air monitoring station prior to the MOOSE field campaign in 2021. Additional research-grade instruments deployed at this station included: (1) Xact 625 particulate metal analyzer (Pall Corporation, Port Washington, NY, USA); (2) online gas chromatograph (AMA Instruments GmbH, Ulm, Germany); (3) Vaisala CL51 Ceilometer (Vaisala, Helsinki, Finland); (4) Pandora spectrometer [20]; (5) Vaisala Weather Transmitter WXT520 (Vaisala, Helsinki, Finland). All enhanced air monitoring activities are currently ongoing at Windsor West station except that the ceilometer was decommissioned in March 2023.

During the MOOSE intensive field campaign in 2021 (Figure 2), ECCC conducted high-resolution, real-time meteorological and air quality forecasts to guide the deployment of mobile platforms on both sides of the Border by using ECCC's operational Global Environmental Multiscale-Modeling Air-Quality and Chemistry (GEM-MACH) model [21] with a nested domain covering SEMI and southern Ontario at 2.5 km grid spacing. The GEM-MACH model was further used to simulate episodic ozone events in the Great Lakes region, with the aim of characterizing the dynamics of lake breezes, accounting for the influence of the local urban heat island.

The activities of the three mobile labs on a given day were determined by a conference of the field study teams based on daily real-time meteorology and air quality forecasts provided by ECCC. These forecasts also guided flights of a NASA Gulfstream aircraft equipped with a UV-visible spectrometer capable of measuring column densities of formaldehyde and NO_2 at sub-kilometer resolution. The three mobile labs sometimes collaborated with each other to map ozone and ozone precursor concentrations in relation to lake breeze fronts, especially during high ozone episodes, or to perform coordinated transects on either side of the US–Canada Border. For example, lake breeze effects were observed during regional transects via elevation of the background levels of CO and ethane. The mobile laboratories also worked individually to characterize point source emissions in the Border region.

Among the emission sources investigated by the mobile labs in Michigan were landfills in SEMI, two of which were also subject to monitoring by EGLE with sensors mounted on Unmanned Aerial Vehicles (UAVs), obtained with funding from the US Department of Energy. The AML and MPAL also investigated methane leaks from underground pipelines in SEMI as part of the MERLIN sub-experiment.

Datasets for the campaign were uploaded to a centralized repository hosted by NASA (see data accessibility statement). The data have undergone extensive analyses using advanced techniques such as very high-resolution 3D modeling at regional, urban, and neighborhood scales, fine-scale inverse modeling of emissions based on measured ambient air concentrations, chemical fingerprinting based on real-time measurements, and source apportionment with positive matrix factorization (PMF). Major policy-relevant results of completed analyses are presented in the following section.

Figure 2. Examples of ground mobile, airborne, and stationary measurement platforms deployed during the MOOSE field campaign.

Figure 2. Examples of ground mobile, airborne, and stationary measurement platforms deployed during the MOOSE field campaign.

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3. Major Field Study Findings and Implications

3.1. Findings Relevant to Ozone Maintenance or Attainment in Southeast Michigan

Conclusions drawn from recent analyses of MOOSE field study data that are relevant to maintenance or attainment of the US ozone NAAQS in SEMI are highlighted in bold.

Local ozone production in SEMI is likely most sensitive to VOC emission controls.

VOCs and NO_x are the two main types of O_3 precursors that are directly emitted into air by industrial, automotive, consumer and commercial, and natural sources. Knowing which type of precursor most controls the amount of O_3 formed in an airshed is vital to identifying the most effective control strategies for inclusion in a State Implementation Plan (SIP) to attain the US O_3 NAAQS.

Based on prior analyses of satellite column and ground-based monitoring data, ozone modeling and trend assessments, and weekday–weekend differences, the Lake Michigan Air Directors Consortium (LADCO) had previously identified SEMI as in a transitional regime evolving away from VOC sensitivity towards NO_x sensitivity ([22] and references therein). Xiong et al. [23], however, used the observed ratio of formaldehyde (HCHO) to nitrogen dioxide (NO_2) in near-surface ambient air measured by the AML during MOOSE and a zero-dimensional (0-D) photochemical box model, F0AM (the Framework for 0-D Atmospheric Modeling), utilizing an extensive set of contemporaneous speciated VOC, NO_x, and O_3 measurements to analyze the sensitivity of local ozone in SEMI to VOC and NO_x controls. F0AM model sensitivity simulations by Xiong et al. [23] suggest that the $HCHO/NO_2$ ratio for the transition between the VOC- and NO_x-limited O_3 production regimes is 3.0 ± 0.3 in SEMI. The midday (12:00–16:00) averaged $HCHO/NO_2$ ratio during the MOOSE intensive campaign was 1.6 ± 1.0, implying that local O_3 production in SEMI is limited by VOC emissions.

Emissions of formaldehyde may be severely underestimated in official inventories. Formaldehyde controls are five times more effective by weight than NO_x controls in reducing ozone at monitors exceeding the NAAQS in SEMI.

Formaldehyde (HCHO) is a VOC that is especially important in ozone chemistry, given its role as an initial radical precursor [24]. It is also a carcinogen with additional non-cancer impacts that poses significant risks to human health [25]. A joint study by EGLE, Georgia Institute of Technology (Georgia Tech), and LADCO demonstrated that air quality models based on current emissions inventories drastically underpredict ambient HCHO compared to measurements at EGLE monitoring stations in SEMI, and that plausible order-of-magnitude corrections to the inventory for SEMI may result in over 1000 US tons per year total additional HCHO emissions [26]. Moreover, the same study showed that such plausible corrections to the HCHO inventory in a high-resolution (1.3 km horizontal grid) air quality model (CAMx) resulted in unexpectedly high ambient HCHO concentrations in the vicinity of New Haven, Michigan, which were confirmed by measurements during MOOSE.

Olaguer [27] used an advanced microscale (400 m grid) forward and inverse model (MicroFACT) constrained by AML ambient air measurements to rigorously estimate emissions in the Dearborn/southwest Detroit area, and to conclude that several large industrial facilities may emit over 1 US ton of HCHO per year, typically two orders of magnitude above values reported to or inferred from activity data using USEPA emission factors [28] by the State of Michigan. The microscale model also helped to explain the observed horizontal gradient in routine stationary measurements of HCHO performed by EGLE using the dinitrophenylhydrazine (DNPH) cartridge technique. This gradient was attributed to local primary (directly emitted) HCHO rather than secondary (atmospherically formed) HCHO.

A related modeling study by Georgia Tech [29] simulated the ozone impacts of various SEMI control strategy options being considered by EGLE, including Reasonably Available Control Technology (RACT) required by the US Clean Air Act for moderate ozone nonattainment areas. HCHO emission reductions were found to be five times more effective on a pound-for-pound basis than NO_x reductions in mitigating ozone at monitors in SEMI that previously exceeded the NAAQS. This study indicates that HCHO may be the most important VOC to control for ozone mitigation in SEMI.

Industrial solvent VOC emissions are substantial and possibly under-reported. Controlling these emissions may have significant ozone mitigation benefits.

Solvents are part of a subset of VOCs referred to as Volatile Chemical Products (VCPs). Estimates of VOC emissions from solvent use have recently increased. The USEPA has updated solvent emissions in the 2020 US National Emissions Inventory (NEI) based on the Volatile Chemical Product framework (VCPy) [30]. However, fugitive emissions of solvents from industrial manufacturing operations are very difficult to quantify and may still be considerably underestimated due to the lack of reliable emission factors. During MOOSE, the AML found significant enhancements of VOCs such as acetone, aromatics, and chlorinated solvents downwind of industrial facilities, including auto makers, chemical waste sites, and coatings or cleaning product manufacturers, possibly indicating emissions from paint, coatings, and solvent use [31,32]. Trans-border emissions from certain large Canadian point sources were also observed on the US side of the Border [32].

Stroud et al. [33] used the Canadian GEM-MACH model to assess the importance of solvent emissions (see Section 3.2). GEM-MACH at 2.5 km grid spacing was evaluated for 8 h daily ozone with 2018 summer data at Windsor and showed good skill (model vs. measurements, slope = 1.04, correlation, R = 0.79). A GEM-MACH simulation of a 2021 ozone episode with U.S. VCPy emissions yielded similar maximum ozone reductions in Detroit (~0.6%) for 10% emission reductions in either solvents or mobile source NO_x. The contribution of solvent use to mono-aromatics in Detroit for the ozone episode was estimated at 60%.

Fugitive releases of methane from landfills and leaking natural gas pipelines may be large enough to significantly enhance ozone formation by VOC and NO_x sources.

Methane is not only a powerful greenhouse gas but can also enhance global concentrations of tropospheric ozone, another important greenhouse gas [34]. Although methane is an organic compound, it is not classified by the USEPA as a VOC due to its low reactivity compared to other organics, which limits the amount of local ozone it can form under normal conditions. However, large volumes of methane released from landfills and leaking natural gas pipelines may compensate for methane's low reactivity in enhancing O_3 formation by local sources of VOC and NO_x. Olaguer [35] applied the MicroFACT fine-scale air quality model to estimate O_3 impacts up to ~30 km downwind of a single hypothetical landfill in SEMI and concluded that a large methane leak of 3000 kg/h could enhance local ozone formation by landfill emission sources of O_3 precursors by at least a tenth of a ppb, and possibly several times more if sources of VOC and NO_x other than the landfill itself were accounted for.

During MOOSE, several advanced techniques were deployed by a team of Michigan scientists and engineers to measure methane emissions from two landfills in SEMI [36]. These techniques included mobile infrared cavity ringdown spectrometry, UAV-mounted meteorological sensors and tunable diode laser spectrometry, estimation of total landfill emissions of methane based on flux plane measurements, and Gaussian plume inverse modeling of distributed methane emissions in the presence of complex landfill terrain. The total methane emissions measured at the two landfills were of the order of 500 kg/h, with an uncertainty of around 50%. The results indicated that both landfill active faces and leaking gas collection systems are important sources of methane emissions.

Xia et al. [37] used the MPAL to measure ambient levels of methane at eight large operating landfills in SEMI. Elevated methane levels were typically found along the downwind side or corner of the landfills, reaching up to 38 parts per million by volume (ppm) in the morning and dropping to near-baseline levels during midday. Both mechanistically based dilution-type models and multivariate models identified wind speed, boundary layer height, barometric pressure changes, and landfill temperature as key determinants of methane levels, explaining most (r^2 = 0.89) of the variation in the maximum methane levels at the most-visited landfill.

The University of Michigan and Aerodyne mobile laboratories also measured ambient methane concentrations in the vicinity of natural gas pipelines and distribution networks. The MPAL collected 20 days' worth of 1 s methane measurements over 1100 km of surface streets in Detroit and detected 534 distinct methane peaks, equivalent to roughly one peak per 2 km traveled [38]. The AML, on the other hand, made repeated traverses of a heavily industrialized area in Dearborn and southwest Detroit where natural gas leaks were frequently encountered [32]. Methane emissions from a persistent leak observed at the intersection of Dearborn Street and Fort Street were quantified using an inverse model and found to be around 200 kg/h [39].

Temporary storage of NO_x in reactive nitrogen reservoir compounds such as HONO and HNO_3 may be inadequately simulated in current air quality models. This may affect estimates of ozone formed both locally and from precursors transported farther downwind of urban emission sources.

In the summers of 2021 (June 7–29) and 2022 (June 6–28), Chai et al. [40] performed speciated sample collections (3–12 h integration time) to quantify the isotopic composition ($^{15}N/^{14}N$, $^{17}O/^{16}O$, $^{18}O/^{16}O$) of the O_3 precursors, NO_x, NO_2, and nitrous acid (HONO), as well as their oxidation products, nitric acid (HNO_3) and particulate nitrate. These offline measurements were combined with real-time measurements of NO, NO_2, and O_3 to characterize the sources, chemical pathways, transport, and sinks of reactive nitrogen species under the influence of urban emissions and changing meteorological conditions, especially the land–lake breeze.

HONO and HNO_3 are important temporary reservoirs of NO_x. In addition to being a NO_x reservoir, HONO is also a radical precursor on par with HCHO [24]. The radicals generated by HCHO and HONO, both relatively short-lived compounds, determine how much local O_3 is formed in an airshed from emissions of VOC and NO_x. HNO_3, on the other hand, is much longer-lived and can re-release sequestered NO_x back to the atmosphere after traveling long distances downwind of the original NO_x sources.

Reactive nitrogen measurements were conducted at two sites during MOOSE: an urban Detroit site (Trinity) which is greatly influenced by emissions from motor vehicles, urban soils, and industrial sources, and a suburban site (New Haven) ~40 miles north of Detroit and typically downwind of major urban emission sources during ozone episodes. Measured HONO concentrations ranged from 0.6 to 4.0 ppb and 0.4 to 3.0 ppb at Trinity and New Haven, respectively, in 2021, whereas HONO concentrations significantly decreased in 2022 with corresponding ranges of 0.4–2.1 ppbv and 0.3–1.9 ppbv. Over both summers, the average ratio of offline HONO to real-time NO_x in New Haven was 2–3 times that at Trinity.

Preliminary stable isotopic composition measurement and analysis performed by Chai et al. [41] demonstrated interesting differences in source contributions and secondary chemistry influence between urban and suburban sites. The isotopic data provided direct evidence of secondary HONO production via O_3 in reactive nitrogen cycling during a lake breeze in addition to impacts on O_3 over land. It also appears from the offline measurements that local concentrations of HONO may be much larger than concentrations of nitric acid with [HONO]/[HNO_3] in the range of 1–21 (mean = 3), contrary to the predictions of standard air quality models. The cycling of reactive nitrogen reservoirs may thus require improvements in future models. This may affect both the simulated efficacy of local control strategies and the influence of an urban airshed on modeled ozone in areas far downwind.

Contributions of secondary sulfate and nitrate to $PM_{2.5}$ in Detroit are lower than in previous assessments, and mobile sources now represent the dominant $PM_{2.5}$ contributor.

Yang et al. [42] applied the PMF source apportionment technique with spatially and temporally diverse datasets to assess source contributions and temporal trends of $PM_{2.5}$ pollution in Detroit, Michigan, including pandemic-related effects. The approach consolidated measurements from 2016 to 2021 collected at three sites where long-term $PM_{2.5}$ levels averaged from 8.63 to 10.83 μg m^{-3}. Most $PM_{2.5}$ was due to mobile sources (characterized by elemental and organic carbon with some K^+) representing 33–44% of $PM_{2.5}$, depending on site and apportionment approach, followed by secondary sulfate at 24–29% of $PM_{2.5}$, and then secondary nitrate at 17–22% of $PM_{2.5}$. Smaller contributions arose from soil/dust, ferrous and non-ferrous metals, and road salt sources. Several sources varied significantly by season and site. Pandemic-related changes were generally modest. Compared to earlier apportionments, contributions of secondary sulfate and nitrate were lower, and mobile sources now represent the dominant $PM_{2.5}$ contributor.

3.2. Findings and Implications of Canadian Studies during MOOSE

Conclusions drawn from analyses of MOOSE field study data relevant to air quality improvement in southern Ontario are summarized below.

Entirely different target abatement actions may be required to reduce VOC emissions.

Healy et al. [19] collected VOC data over five days in a heavily industrialized region of southwestern Ontario containing several refineries, petrochemical production facilities, and a chemical waste disposal facility by using a mobile monitoring platform. PMF analysis was used to apportion industrial VOCs with high time-resolution measurements collected while stationary and while moving. Concentrations of VOCs (including toluene, benzene, methyl ethyl ketone, and butene) were generally elevated close to industrial facilities. Factors associated with petroleum, chemical waste, and rubber production were identified and ambient mixing ratios of selected aromatic, unsaturated, and oxygenated VOCs were apportioned to local and background sources. Fugitive emissions of benzene, highly localized and predominantly associated with storage facilities, were found to be the dominant local contributor to measured ambient benzene mixing ratios. Toluene and substituted aromatics were predominantly associated with refining and traffic, while methyl ethyl ketone was linked to chemical waste handling. The findings indicated that entirely different target abatement actions would be required to reduce local emissions of each of these VOCs. The approach to source apportionment of VOCs in this study, using fine spatial and temporal resolution, can be used to identify problematic source locations and to inform VOC emission abatement strategies.

A combined precursor reduction strategy is required to address both regional and local contributions to ozone production.

Stroud et al. [33] studied the impact of solvent emissions on reactive aromatics and ozone in the Great Lakes region by using both ECCC's operational air quality GEM-MACH model and a PMF model. VOC emissions from solvent use have increased as urban areas expand while transportation emissions have declined over the past decades. This study found that when the 2015 Canadian emissions and 2017 US emissions were used, model estimates of total mono-substituted aromatics from solvent emissions were smaller in Windsor than estimates from PMF analysis based on the 2018 measurements. The use of updated US solvent emissions for summer 2021 simulations increased the solvent use contributions and provided a more unform spatial distribution across the US–Canada Border. Long-chain alkanes were the dominant species in the model's air pollutant emission inventory and in the observation-derived solvent use factor.

The modeling further showed that summertime 8 h daytime O_3 levels decreased by 0.4% over Windsor when solvent use emissions were reduced by 10%. A 10% NO_x reduction from transportation emissions resulted in a 0.6% ozone decrease over Windsor and more widespread changes over the Great Lakes region. A combined regional-scale NO_x reduction from transportation sources and more localized industrial VOC source reductions in the Border region is likely the optimal strategy for reducing ozone episodes in southern Ontario. VOC reductions also have the co-benefit of decreasing public exposure to some toxic VOCs and secondary particulate matter.

A recent Canadian study by Zhang et al. [43] analyzed weekday/weekend data at Canadian and US urban sites in the Border region. The study showed that ozone in this region had a greater weekend positive increment due to lesser NO titration. Overall, the O_3

formation regime gradually shifted from VOC toward NO_x sensitivity during 1996–2007 then became more sensitive to VOCs during 2008–2015.

Local traffic and regional/transboundary industrial sources contribute about equally to particulate matter-bound elemental pollution in Windsor, Ontario.

Zhang et al. [44] assessed hourly measurements of $PM_{2.5}$-bound elements and black carbon collected from April–October 2021 at Windsor West station. A clear diurnal pattern was observed for most of the elements, likely related to the evolution of atmospheric mixing heights and local anthropogenic activities. Conversely, sulfur showed elevated levels in the afternoon, suggesting secondary formation of particulate sulfate from sulfur dioxide when ambient temperatures are high. Five source factors were identified by using the USEPA PMF model: three traffic-related sources (i.e., vehicular exhaust, crustal dust, and vehicle tire and brake wear factors), and two industrial sources (i.e., coal/heavy oil burning and metal processing factors). The three traffic-related sources were mostly local and contributed 47% to the total elemental concentrations, while the two industrial sources originated from regional/transboundary sources and contributed 53%.

Zhang et al. [45] conducted five additional scenarios of the PMF modeling to assess impacts of input data on source identification, source contribution, and model performance by using concentrations of $PM_{2.5}$-bound elements in Windsor, Ontario. The model outcomes and performance were found to be insensitive to data below method detection limits (MDLs) being replaced with $\frac{1}{2}$ MDLs, and to whether brown carbon data were excluded. Unique factors of fireworks and mineral dust were identified by analyzing two episodic events individually. Moreover, PMF model performance was improved greatly for event markers of the episodes and elements with less variability in concentration when compared with the base case scenario. Overall, the PMF model outcomes and performance were sensitive to the fraction of concentration measurements below MDLs and element concentrations with large variability due to high concentrations observed in episodes. The findings are useful for dealing with data below MDLs and episodic events in conducting future PMF source apportionment.

More accurate initialization of meteorological models may improve regional air quality model predictions of ozone, especially at levels exceeding the CAAQS.

Mashayekhi et al. [46] investigated the influence of meteorology initialization on prediction of surface O_3 in summer 2021 in the Great Lakes region by using ECCC's operational GEM-MACH model at a horizontal resolution of 2.5 km. In comparison to the conventional initialization (i.e., single-time full-field digital filter), the advanced meteorology initialization technique of the four-dimensional incremental analysis updating (IAU) method improved the model performance of surface O_3 for both exceedances and non-exceedances of the 2025 CAAQS of 60 ppb. The study highlights the importance of meteorological parameters in predicting surface O_3 levels. It was also found that the simulation initialized at 18Z demonstrated superior performance of the surface O_3 prediction, especially during days when O_3 levels exceeded the threshold of 60 ppb. In-depth analysis further indicated that better prediction of surface O_3 in the Great Lakes regions is linked to a more accurate representation of wind speed in the afternoon when O_3 levels are high.

4. Discussion and Conclusions

The results to date of the MOOSE field campaign have yielded important policy-relevant conclusions that can lead to improved air quality strategies in the US–Canada Border region. In SEMI, the results point to VOC controls as the necessary primary focus of local ozone mitigation efforts, especially the identification, quantification, and reduction of emissions of formaldehyde and, secondarily, industrial solvents. The control of NO_x emissions, however, may still be important in reducing regional ozone pollution. The State of Michigan's efforts at greenhouse gas reduction should also consider the local and regional ozone co-benefits of identifying, quantifying, and reducing emissions of methane from landfills and natural gas pipelines.

In southern Ontario, local air quality will benefit from O_3 and $PM_{2.5}$ precursor reductions in Michigan due to the importance of transboundary pollution from the US. The extensive presence of the Canadian petrochemical industry in southwestern Ontario may require authorities to re-examine the accuracy and completeness of local emissions inventories related to products of incomplete combustion, including formaldehyde, as well as inventories of solvents and other VOCs. This is because GEM-MACH simulations suggest that VOC reductions in the Border region may yield comparable ozone mitigation benefits to mobile source NO_x reductions during ozone episodes.

Among the control strategies that could be evaluated by regulators on both sides of the US–Canada Border are: (1) flare elimination, minimization, and/or efficiency improvement; and (2) oxidation catalysts, which can decrease HCHO emissions from stationary engines by 96% according to State of New Jersey data [47]. The first strategy has been successfully implemented by the US petrochemical industry and may be imitated by the steel and coking industries in Michigan. Oxidation catalysts, on the other hand, could be considered as possible controls for large stationary engines at natural gas pipeline stations, gas-fired units at power plants, and landfill gas-to-energy conversion facilities.

In the case of fugitive emissions of organic solvents and methane, a major priority should be the development and implementation of contemporary methods for leak detection and repair (LDAR). The use of fast chemical instrumentation and inverse modeling methods applied during the MOOSE campaign, unlike more commonly used LDAR techniques, is scalable to large facilities and could be considered for wider adoption.

Lastly, the results of MOOSE emphasize the importance of improving modeling practice to better assess the impacts of control strategies in the Border region, including the use of finer-resolution air quality models and updating of initialization techniques in meteorological models. The USEPA should work with the states to promote the continued update of national formaldehyde and industrial solvent emissions inventories, and to re-examine the treatment of reactive nitrogen reservoirs in regional air quality models. Both these efforts will enhance the ability of regulatory air quality models used in ozone attainment demonstrations to accurately evaluate ozone control strategies. The updating of reactive nitrogen cycling in models will also help improve assessments of long-range transport of ozone and its precursors.

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Majority of US urban natural gas emissions unaccounted for in inventories

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Across many cities, estimates of methane emissions from natural gas (NG) distribution and end use based on atmospheric measurements have generally been more than double bottom-up estimates. We present a top-down study of NG methane emissions from the Boston urban region spanning 8 y (2012 to 2020) to assess total emissions, their seasonality, and trends. We used methane and ethane observations from five sites in and around Boston, combined with a high-resolution transport model, to calculate methane emissions of 76 ± 18 Gg/yr, with 49 ± 9 Gg/yr attributed to NG losses. We found no significant trend in the NG loss rate over 8 y, despite efforts from the city and state to increase the rate of repairing NG pipeline leaks. We estimate that 2.5 ± 0.5% of the gas entering the urban region is lost, approximately three times higher than bottom-up estimates. We saw a strong correlation between top-down NG emissions and NG consumed on a seasonal basis. This suggests that consumption-driven losses, such as in transmission or end-use, may be a large component of emissions that is missing from inventories, and require future policy action. We also compared top-down NG emission estimates from six US cities, all of which indicate significant missing sources in bottom-up inventories. Across these cities, we estimate NG losses from distribution and end use amount to 20 to 36% of all losses from the US NG supply chain, with a total loss rate of 3.3 to 4.7% of NG from well pad to urban consumer, notably larger than the current Environmental Protection Agency estimate of 1.4% [R. A. Alvarez *et al.*, *Science* 361, 186–188 (2018)].

urban | methane | natural gas | greenhouse gas emissions

Atmospheric methane (CH_4) is the second-most important greenhouse gas (GHG) after carbon dioxide (CO_2); the Intergovernmental Panel on Climate Change (IPCC) estimates that it was responsible for ~20% of global anthropogenic direct radiative forcing from 2000 to 2010 (1). Oil and natural gas (NG) systems are estimated to account for 31% of US anthropogenic methane emissions (2). NG emissions have increased over the last decade, as it has become an increasingly important energy source in the United States due to advances in extraction technology, reduction in cost, and its promotion as having lower CO_2-equivalent emissions relative to other fossil fuels.

Densely populated urban areas are well positioned to effect change in GHG emissions, as they have concentrated population, infrastructure, and emissions along with, in many cases, political will to implement emission reductions policies (3). Pipelines, transmission infrastructure, household and commercial appliances, meters, stationary combustion, and service leaks are thought to be the most significant source types for urban NG emissions (2). Bottom-up inventories estimate that distribution and end use contribute 6% of US emissions from the NG supply chain (2), but that estimate is highly uncertain. Urban NG emissions have been reported for several cities including Boston, Indianapolis, Washington, DC, Los Angeles, New York City, and Philadelphia using top-down methods based on tower, aircraft, and remote sensing measurements (e.g., refs. 4–8). Top-down studies consistently estimate distribution and end use NG emissions to be significantly (two to 10 times) larger than the bottom-up estimates. The large gap between bottom-up and top-down analyses indicates that there are likely large missing sources in inventories, and it is unclear from which sector those emissions originate. In order to implement effective GHG mitigation policies, it is necessary to understand the dominant sources of CH_4 emissions from NG distribution and end use.

We present an 8-y top-down study of NG emissions from the Boston urban region to assess the NG loss rate over time and investigate the potential missing sources of NG emissions in inventories. We also assess the impact of the COVID-19 shutdown on CH_4 emissions during April 2020. This is one of only a few long-term, top-down studies of urban CH_4 emissions and is in an east-coast city with older, leak-prone infrastructure. Previous studies in other cities have not found any statistically significant trend in emissions over time (7, 9–11). Boston has set a target of becoming carbon neutral by 2050 (12), and Massachusetts has been working to reduce NG leaks, with several laws and regulations implemented between 2014 and 2019 requiring timelines for utilities to report and repair large leaks

Significance

Methane emissions from distribution and end use of natural gas (NG) are not well known. We analyzed atmospheric methane measurements to quantify NG emissions in the Boston area over ~8 y, finding NG emissions approximately three times larger than calculated by usage-based inventories. We observed no change in emissions over 8 y despite efforts from the state to address NG pipeline leaks. Seasonal emissions are directly related to consumption of NG, implying that sources other than pipelines, such as transmission and appliances, are important and may require future policy action. We estimate total supply chain losses of 3.3 to 4.7% for NG consumed in urban areas, which significantly increases the climate impacts of NG compared to Environmental Protection Agency estimates.

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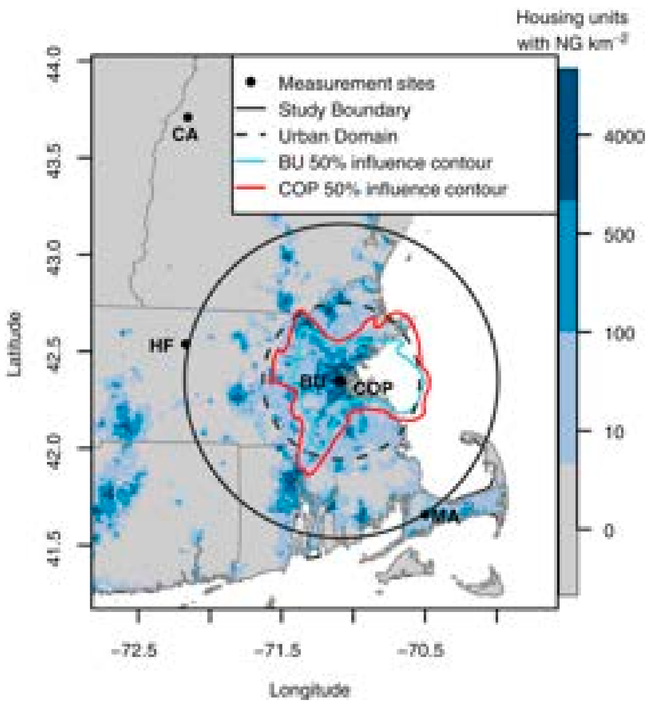

Fig. 1. Map of measurement stations in the Boston network. Study Boundary (black line) bounds the 90-km radius circle in which emissions were optimized. Urban Domain (dashed line) bounds the area for which optimized emissions were reported. The blue shading represents the number of housing units with NG per square kilometer (4). The red (blue) contour encloses 50% of the average footprint (sensitivity area) initiated at the COP (BU) site.

based on their size (13, 14); our study will assess whether these efforts have produced a measurable change in NG emissions.

To put this study in context with other cities and evaluate current knowledge of CH_4 emissions from NG distribution and end use, we then compare top-down NG emission estimates from four US cities with new studies estimating bottom-up emissions from pipeline leaks and in-house losses. By updating top-down versus bottom-up comparisons with the latest available data, we assess the current understanding of the total carbon footprint of NG, the state of the NG budget, and how well we can constrain urban end-use emissions.

Methods

Atmospheric CH_4 concentrations were measured continuously using Picarro cavity ring down spectrometers at two sites in Boston near the urban center, Boston University (BU) and Copley Square (COP), and three locations 90 to 175 km outside of Boston at Harvard Forest in Petersham, MA (HF), Canaan, NH (CA), and Mashpee, MA (MA) (Fig. 1 and *SI Appendix*, Table S1) from September 2012 to May 2020. BU, COP, and HF are operated by Harvard while CA and MA are operated by Earth Networks Inc. and the National Institute of Standards and Technology. The urban sites at BU and COP are 1.7 km apart and sample at 29 m and 215 m above ground level, respectively, providing a direct observation of the surface-layer vertical gradient.

The model-measurement approach used in our inverse analysis has been described by McKain et al. (4) who analyzed CH_4 observations from 2012 to 2013 and Sargent et al. (15) who analyzed CO_2 observations from 2013 to 2014. Briefly, we modeled changes in the CH_4 concentration as air traveled from the boundary of our study region, a 90-km radius circle centered on Boston, to our urban measurement sites at BU or COP. The modeled CH_4 enhancement (ΔCH_4) above the concentration at the region boundary was determined using the Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model (16) run in the recently upgraded "Stochastic Time-Inverted Lagrangian Transport (STILT) mode" coupled with a spatially resolved bottom-up inventory of CH_4 emissions (4).

The HYSPLIT model released an ensemble of 500 particles at each hour at the urban measurement sites (receptors) and followed their trajectories backward in time based on wind fields and turbulence. We used two meteorological drivers, the North American Mesoscale Forecast System (NAM) at 12-km resolution and the High-Resolution Rapid Refresh (HRRR) at 3-km resolution (available 2017 through 2020). HYSPLIT generates an influence function ("footprint" units: parts per million CH_4 per unit flux in μmole*meter^{-2}*second^{-1}), which quantitatively links upwind surface fluxes to changes in CH_4 concentration at the receptor. In the near-field, the mixing layer height in HYSPLIT was adjusted based on the particle heights as described in ref. 15 to better account for the particles' interaction with the surface before they are fully mixed through the planetary boundary layer.

The footprints were convolved with a 1-km resolution prior model of anthropogenic and biogenic CH_4 emissions previously described by McKain et al. (4), which was augmented with updated landfill and NG point source fluxes (17–19), residential (20–22) and commercial (23) building losses, and seasonally varying wetland emissions (24) (*SI Appendix*, section S2). The inventory also included newly reported pipeline losses from Weller et al. (25), who assessed pipeline leaks with methane analyzers driven through four cities, covering ~10,000 km of pipelines. The convolution of the HYSPLIT footprint within our study region and gridded prior emissions enabled us to compute ΔCH_4, the expected increase in CH_4 concentration between our study boundary and urban measurement site based on the bottom-up emissions estimate.

Ethane (C_2H_6) measurements from the two urban sites as well as aircraft measurements were used to quantify the fraction of the observed ΔCH_4 that was due to NG emissions. Ethane is a significant component of NG, whereas microbial CH_4 sources, such as landfills, sewage, and wetlands, produce little or no ethane (26). Because Boston has no geologic CH_4 seeps, no oil and gas production or refining, and low rates of biomass burning, there are no known significant sources of ethane in the region other than NG. Ethane concentrations were measured using a laser spectrometer (26) at BU for 3 mo in the fall and winter of 2012 to 13 and 1 mo in the late spring of 2014 (5); they were measured via aircraft in August/September 2017 and March 2018 (27); they were also measured at COP for 5 mo in the fall and winter of 2019 to 2020. Following the method of McKain et al. (4), the atmospheric C_2H_6:CH_4 ratio was determined from the slopes of colocated C_2H_6 versus CH_4 measurements and compared to the C_2H_6:CH_4 ratio of NG flowing into the region during the measurement period (*SI Appendix*, section S3 and Fig. S1). The percentages of observed CH_4 due to NG from these three studies are shown in Table 1, with average values of 91% NG in the dormant season and 76% in the growing season. The aircraft study shows a much smaller change in NG fraction with season than the tower study, likely because the aircraft sampled a smaller, more urban domain with less biogenic emissions. Due to large uncertainties in prior NG emissions estimates, the NG emissions layer in our prior inventory was scaled to be consistent with the attribution results from ethane data. Without adjusting the biogenic component of prior CH_4 emissions, the prior NG emissions were scaled such that they contributed on average 91%, 84%, and 76% of the footprint-weighted ΔCH_4 at the urban sites in the dormant, transitional, and growing seasons, respectively. Unscaled priors were also tested, along with NG fractions spanning the range of observed values and a range of wetland emissions from different inventories.

The CH_4 concentrations at the boundary of the study region were calculated as the lower 20th percentile, 48-h running average of CH_4 measurements from the HF, CA, or MA sites, with the upstream site chosen based on the average azimuth at which the HYSPLIT particles exited the 90-km radius circle around Boston. The model selected the MA site for exit angles from 120 to 180°, the HF site for 180 to 300°, and the CA site for 300 to 360°.

Observations corresponding to easterly wind directions (0 to 120° exit azimuth) were discarded due to lack of a suitable boundary site and uncertainty in modeling sea breezes that account for a significant fraction of the easterly inflow conditions. As westerly winds are the most common, this criterion excluded 25% of days in the spring and fall and 11% of days in the winter. During sea breeze conditions, air can recirculate over the city, picking up large amounts of pollution. This is very difficult for the HYSPLIT model to capture accurately using regional scale meteorology (28); we therefore excluded these angles.

The observed ΔCH_4 was calculated as the difference between the observed CH_4 at each urban site and the background concentration, with a time delay between the upwind and downwind sites equal to the average travel time from the receptor to the study region boundary. Hourly average ΔCH_4 values were aggregated into daily afternoon averages (11 to 16 h EST) to focus on periods when the atmosphere is well-mixed.

Optimized CH_4 emissions were calculated for groups of 2mo with similar NG consumption (January/February, December/March, November/April, May/October, June/September, and July/August) in each year from September 2012

Table 1. Fraction of atmospheric CH_4 attributed to NG sources based on three measurement campaigns

	Time period	Location	Dormant	Growing
Ref. 4	2012 through 2013	BU	98%	67%
Ref. 27	2017 through 2018	Aircraft	87%	85%
This work	2019 through 2020	COP	88%	

to May 2020 (or for single months for which a corresponding month was not available). For each 2-mo group, a single scaling factor (SF) was determined by dividing the mean observed CH_4 enhancement by the mean modeled CH_4 enhancement:

$$\mathrm{SF} = \mathrm{mean}(\Delta CH_4\mathrm{obs})/\mathrm{mean}(\Delta CH_4\mathrm{model}).$$

Optimized ΔCH_4 and ΔNG emissions were calculated as the product of the prior emissions and the SF for each period:

$$CH_4\mathrm{optimized} = CH_4\mathrm{boundary} + \mathrm{SF} * \Delta CH_4\mathrm{model}.$$

We compared optimized emissions from the portion of MA within our 90-km circle to state-level monthly NG consumption (29) multiplied by 0.88, the fraction of state NG use estimated to be within our study area based on the spatially resolved map of NG consumption from McKain et al. (4). We did not include the emissions or consumption from other states because the vast majority of the HYSPLIT footprint falls within MA. Fractional loss rates to the atmosphere were obtained by dividing optimized NG emissions by total NG consumption in MA and within the study region. Uncertainties in optimized emissions were calculated through a bootstrap analysis that accounted for variations of hourly and daily observed and model enhancements and boundary CH_4, as well as uncertainties in prior emissions and atmospheric transport.

Results

We quantified average methane emissions within a 45-km radius of Boston to be 37.5 ± 9 $g \cdot m^{-2} \cdot y^{-1}$ (95% CI) from 9/2012 to 5/2020, with 24.1 ± 4.6 $g \cdot m^{-2} \cdot y^{-1}$ of that total originating from NG, corresponding to total emission of 49 Gg/yr of NG methane from this region. Average NG emissions in the 90-km radius study domain were 14.0 ± 2.7 $g \cdot m^{-2} \cdot y^{-1}$, which is comparable to the value of 15.3 ± 3.5 $g \cdot m^{-2} \cdot y^{-1}$ calculated by McKain et al. for the same domain (4). The 45-km radius study area corresponds to ∼50% of the HYSPLIT footprint influence (Fig. 1) and approximates the Boston urban area defined by the US Census Bureau Topologically Integrated Geographic Encoding and Referencing (TIGER) database (30).

We found an average NG loss rate of 2.5 ± 0.5% from 2012 to 2020 by comparing NG emissions to consumption in our study area. There was no statistically significant trend in loss rate over our 8-y study period (Fig. 2), despite new regulations in Massachusetts requiring utilities to repair large leaks (14). We also saw no trend in ΔCH_4 between our Boston and background sites over that time period (*SI Appendix*, Fig. S3). Our calculated loss rate is three times higher than the 0.8% loss rate indicated by our prior inventory for Boston and six times higher than the Massachusetts Department of Environmental Protection (MassDEP) estimate and the Gridded Environmental Protection Agency (EPA) inventory (31), neither of which include end-use emissions. The variability among the three inventories shown in Fig. 2 is mainly due to using pipeline emission factors based on different studies.

From 2017 to 2020, we calculated a loss rate of 2.4 ± 0.5% using the HYSPLIT model; the loss rates calculated using the NAM 12-km resolution and HRRR 3-km resolution meteorologies were indistinguishable. These rates and the 2.5 ± 0.5% loss rate based on NAM for 2012 to 2020 are comparable to the 2.7 ± 0.6% loss rate calculated by McKain et al. (4) from 2012 to 2013 using the Weather Research and Forecasting (WRF) model meteorology and the STILT model. The excellent agreement among models using three different meteorology products and two transport models provides confidence that wind errors are not the cause of discrepancies between top-down and bottom-up studies. There was also excellent agreement in annual average emissions between analyses based on the COP and BU sites (Fig. 3), providing confidence in the total emissions and temporal trends.

As a check, we also calculated methane emissions for December 2013 through February 2014 using the observed atmospheric CO_2:CH_4 ratio and optimized CO_2 emissions calculated by Sargent et al. (15) and calculated a loss rate of 1.7%, slightly lower than our CI. The ratio method uses the Anthropogenic Carbon Emissions System (ACES) CO_2 inventory, which is entirely independent from the methane inventory. This method implicitly assumes that methane emissions are colocated with CO_2 emissions and focused on winter when biological emissions are low and emissions of both species are dominated by anthropogenic sources. This assumption is imperfect given that CO_2 emissions from traffic and CH_4 emissions from landfills and wastewater may not be colocated with the other species, but the method is useful as an independent order of magnitude check. This estimate also gives a loss rate more than double that of bottom-up methods.

Our model reproduced daily and weekly variability in atmospheric CH_4 well (Fig. 4). Both the observed methane concentrations and the enhancement between the urban and background sites were highest in the winter and lowest in the summer (*SI Appendix*, Figs. S3 and S4). Fig. 3 shows a strong seasonal cycle in optimized NG emissions, with a larger amplitude at the COP site than at the BU site. There is no strong seasonal variability in optimized total CH_4 emissions (*SI Appendix*, Fig. S7). The seasonal variability in NG emissions is larger than the variability in the observed ΔCH_4, because the C_2H_6:CH_4 ratio indicates a larger fraction of CH_4 from NG in the winter than in the summer, while wetland CH_4 emissions peak in the summer.

Summer NG emissions at COP and BU were 58% and 28% lower, respectively, than winter emissions. The difference in seasonal amplitude between the two sites is likely due to different emitters in the footprints of each site, with a larger fraction of NG emissions in the footprint of the BU site that are independent of season, such as restaurants and pipeline leaks. We expect the much taller COP site, which samples at 215 m, to be more representative of regional emissions, while the 29 m BU site is more sensitive to local emissions. Though the amplitude of the seasonal cycles differs at the two sites, the average

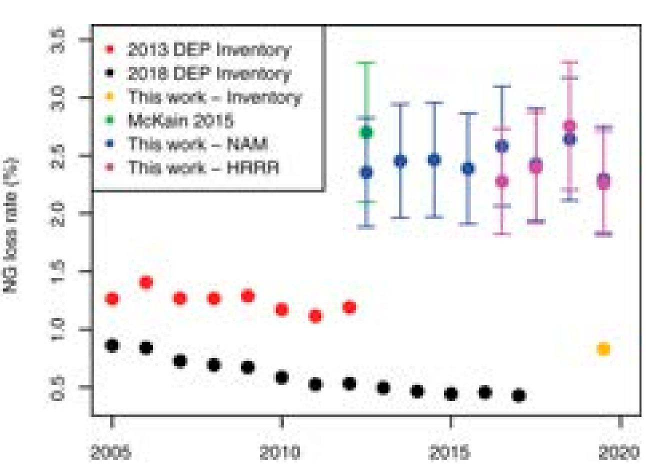

Fig. 2. Yearly NG loss rates based on inventories released by MassDEP in 2013 (red) and 2018 (black), calculated with a top-down method by McKain et al. (4) (green), by this work from the inventory (orange), and top-down analysis using NAM12 (blue) or HRRR (purple) meteorology. Error bars were calculated using a bootstrap method and represent 95% CI.

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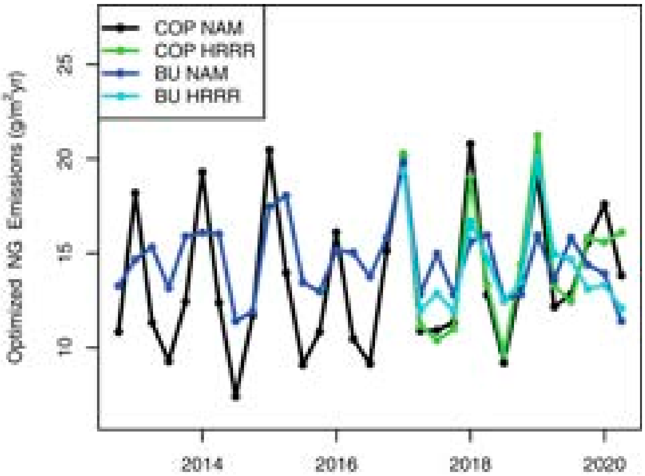

Fig. 3. Seasonal average optimized NG emissions (grams/meter^{2}year) based on observations at the COP and BU sites using NAM12 or HRRR meteorology.

annual emissions and temporal trends calculated from the two sites are in excellent agreement (Fig. 3).

We find that NG emissions and consumption are highly correlated. This is surprising, because distribution pipelines, thought to be a dominant source of NG losses, are at fairly constant pressure year-round, and thus, their emissions are not expected to vary with consumption. Posterior NG emissions from measurements at the COP site were compared with Massachusetts monthly NG consumption in the study area from the residential, commercial, and industrial sectors from the US Energy Information Administration (EIA) (29) (Fig. 5). As the COP site has a larger footprint than the BU site, we expect state-level consumption values to be more representative of consumption in its footprint than in the BU footprint (city-level NG consumption was not available) (*SI Appendix*, Fig. S5). Fig. 5 shows a weighted, linear least-squares fit between emissions and consumption. The intercept of this line implies a seasonally invariant loss of 6.4 g/m^2/yr which is ∼3 times higher than the pipeline emissions estimated by Weller et al. (25). The slope of this line (0.025) implies an additional loss of 2.5% of consumed NG, which is in good agreement with the 2.5% loss rate calculated by comparing total yearly emissions to consumption. The correlation also holds for total methane emissions during the dormant season (Fig. 5, *Right*, blue points). Note that NG

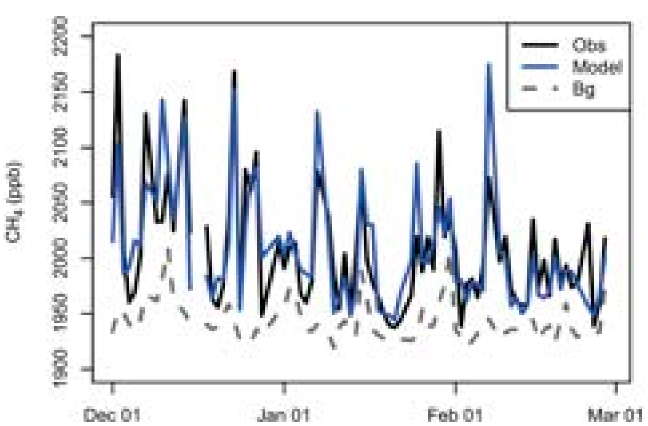

Fig. 4. Observed (Obs), scaled model (Model), and background (Bg) CH_4 at COP. Daily afternoon average (11 to 16 h EST) concentrations for December, January, and February 2014 to 2015.

emissions and consumption are fully independent datasets, as NG consumption was not used in the prior inventory.

In bottom-up studies of residential and commercial buildings, appliances and furnaces were reported to have loss rates of 0.1 to 0.3% of consumed gas (20, 21, 23); transmission (compressor stations, etc.) is estimated to have a loss rate of 0.2% (4). Though we expect the slope of 2.5% at COP (215-m sampling height) to be more representative of regional emissions than the slope of 1% at BU (which, sampling at 29 m, compares fairly local emissions to state-level consumption), even taking a loss of 1% of consumption as a lower bound is significantly higher than is expected from bottom-up inventories. Thus, while there is some uncertainty in the regional seasonality of NG losses based on the difference between our two urban sites, both sites indicate consumption-driven losses that are significantly higher than bottom-up estimates.

To test whether the correlation between emissions and consumption was an artifact of the seasonality of the prior inventory, we performed sensitivity studies with a range of NG fractions and wetland emissions as well as a seasonally invariant prior. These sensitivity studies produced NG emissions within ±20% of the main configuration and maintained the strong relationship between emissions and consumption (*SI Appendix*, section S5). We also ran a test which included angles of 0 to 120°, using MA as a background; it produced NG and CH_4 emissions which agreed with the main configuration to within 2%. Additionally, we compared results with and without MA exit angles, as they can sometimes be difficult to model due to sea breezes. We found no difference in results when MA angles were excluded. We found that the wetland methane source in our prior inventory is not significantly different for east versus west winds, so wind direction could not be used to separate out the wetland methane source.

Total methane emissions do not follow NG consumption in the summer when the ethane:methane ratios indicate that biological sources such as wetlands and landfills are a larger portion of the total methane enhancement in the city. Because they tend to be located farther from our urban sites than the NG emissions, wetland and landfill emissions lead to relatively small changes in concentrations at the receptor. Therefore, our network cannot strongly constrain emissions from biological sources, leading to larger uncertainty in total methane emissions, particularly in the summer, than in NG emissions (*SI Appendix*, Fig. S7). We have confidence in the NG component of methane emissions throughout the year, as these emissions are concentrated near the receptors and strongly influence observations. The optimized emissions of NG are not significantly influenced by adjusting wetland emissions in the prior by up to a factor of 6.

Seasonal changes in urban methane emissions have previously been found by Huang et al. (32) in Washington, DC (summer CH_4 emissions were 41% lower than winter emissions) and He et al. (10), Wong et al. (10), and Yadav et al. (33) in Los Angeles (summer emissions were 26%, 22%, and 40% lower than winter emissions, respectively). However, the fraction of NG was not determined in these studies, which assessed total methane emissions only. The associated consumption in the measurement footprint and relationship to consumption was calculated by He et al., who found a slope of 0.014 between CH_4 emissions and residential and commercial consumption, which is notably lower than the slope of 0.025 (versus NG) or 0.021 (versus CH_4 in dormant season) that we found in Boston. He et al. used a remote mapping spectrometer to measure the CO_2:CH_4 ratio, combined with a prior CO_2 inventory to calculate top-down CH_4 emissions. The difference in slopes could be influenced by the different ages of infrastructure, the types of emitters, and the NG heating demand due to different climates in the two cities.

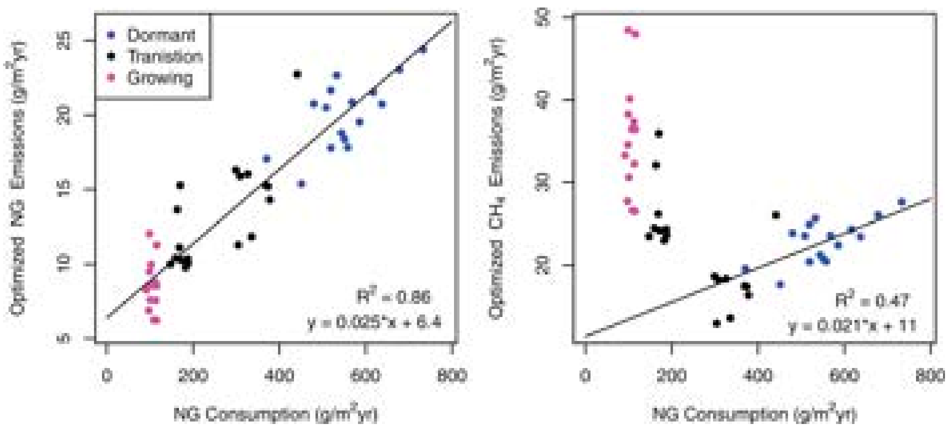

Fig. 5. Optimized NG emissions (*Left*) and total methane emissions (*Right*) compared to residential and commercial NG consumption in MA based on measurements at the COP site. The linear fit to all data (*Left*) and dormant season data (December through March) (*Right*) is shown. Each point represents a 2-mo average.

We were also able to investigate the impact of the 2020 Covid-19 shutdown on methane and NG emissions in Boston. April 2020 emissions of both methane and NG determined by inverse analysis at the BU site were 42% lower than the average of previous April emissions and 22% lower than the lowest April emissions from our study period in 2017. In contrast, April 2020 emissions based on inverse analysis at the COP site were approximately equal to the average of April emissions from 2013 to 2019. Fig. 6 shows that 2020 was the only year in which the average April methane concentration at the 215-m COP site was higher than that at the 29-m BU site (which is only 1.7 km away), demonstrating an inversion of the typical atmospheric concentration gradient.

Massachusetts' total NG consumption during April 2020 showed no change in the residential or industrial sectors compared to previous years, while the electrical sector showed a 35% decrease in consumption compared to 2018 and 2019, and there was a small decrease in commercial consumption (29) (*SI Appendix*, Fig. S8). However, state-level data are not necessarily representative of changes that could have happened locally near BU, as evidenced by the weaker correlation between emissions calculated from the BU site and state-level consumption compared to the correlation at the COP site. The marked decrease in methane emissions at BU could be due to reduced appliance use in office buildings, restaurants, and/or the BU campus surrounding the BU site. There is no evidence that BU buildings changed their heat consumption, though they did stop cooking and serving food. Like the strong correlation between NG emissions and consumption over the 8-y period, the significant change in methane emissions at BU during the Covid-19 shutdown indicates that changes in local consumption are driving methane enhancements and retrieved emissions at this station, reflecting the low sampling altitude (29 m agl). The significant decrease in CH_4 emissions locally around BU during April 2020, when residential NG consumption and pipeline losses were constant, points to the importance of other sources such as beyond-the-meter losses and the necessity of further studies to quantify these sources.

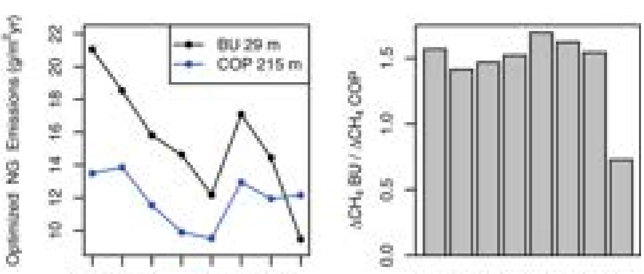

Fig. 6. (*Left*) Mean April optimized emissions from inverse model based on observations from BU or COP site. (*Right*) Ratio of mean April ΔCH_4 BU versus ΔCH_4 COP, in which ΔCH_4 is the enhancement between the urban and background CH_4.

Fig. 7 compares this study's top-down and bottom-up per capita NG emissions for Boston with other cities that have been studied across the United States. We compared seven top-down studies that explicitly calculate NG emissions. In order to compare NG emissions from as many studies as possible, we also calculated the NG component of methane emissions for top-down studies which estimated total methane emissions only by multiplying methane emissions by the fraction of methane from NG determined by other studies of the same city (*SI Appendix*, section S8).

Across the six cities, we find remarkably similar levels of NG emissions when adjusted for population. The emissions per capita are significantly higher than bottom-up estimates in every study, irrespective of the infrastructure age, notwithstanding many differences among study designs. Tower-based, top-down estimates for Boston, Indianapolis, Washington, DC, and Los Angeles were three, six, 10, and two times greater, respectively, than bottom-up estimates. We find that while the updating the Boston inventory with the latest pipeline, appliance, and building losses increased estimated emissions and reduced the gap between top-down and bottom-up studies, large, unexplained gaps remain (Fig. 7*B*). Among these studies, loss rates from NG infrastructure were calculated in different ways; for comparison, we recalculated loss rates for some studies according to our method (*SI Appendix*, Table S3). These studies produce loss rates of 1.1 to 2.1% for Washington, DC (8, 32) and 2 to 2.3% for Los Angeles (9, 35), comparable to the 2.5% shown here for Boston.

Conclusions

Top-down studies which estimate methane emissions from atmospheric concentration measurements are a powerful tool that can be used to quantify the scale of NG emissions and assess how the total carbon footprint of NG compares to that of other fuels. We analyzed nearly 8 y of methane observations from five sites in and around Boston in an inverse model framework and found that NG emissions are three times higher than our bottom-up inventory estimates and six times higher than

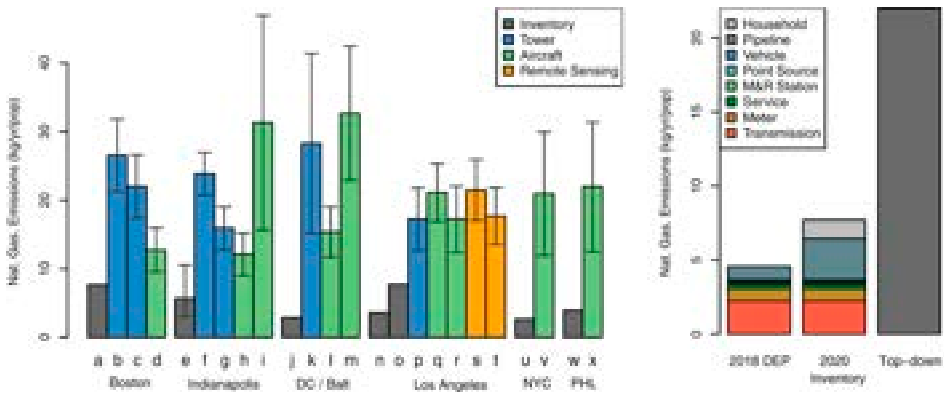

Fig. 7. (*Left*) Per capita NG emissions from top-down studies in six US cities. Boston: (a) This work, (b) McKain (4), (c) This work, (d) Plant (5), Indianapolis: (e) Lamb (6), (f) Lamb (6), (g) Balashov (11), (h) Lamb (6), (i) Cambaliza (34), DC/Baltimore: (j) EPA (8), (k) Huang (32), (l) Ren (8), (m) Plant (5), Los Angeles: (n) CARB (35), (o) EPA (33), (p) Yadav (33), (q) Cui (36), (r) Peischl (35), (s) Wunch (7), (t) Wong (10), New York City: (u) EPA (5), (v) Plant (5), Philadelphia: (w) EPA (5), and (x) Plant (5). (*Right*) Boston bottom-up inventory NG emissions by sector compared to top-down emissions. "2018 DEP": vehicle, point source emissions as described in *Methods*, no household emissions, and all other sources from 2018 DEP (37); "2020 inventory": same as "2018 DEP" except pipeline emissions from Weller et al. (25), household and building emissions from Fischer et al. (20), Lebel et al. (22), and California Energy Commission (23); "Top-down": emissions from this study.

the most recent MassDEP estimate, which does not include end use. Comparing NG emissions to consumption in the region, we find an average loss rate of 2.5 ± 0.5% from urban infrastructure or about 49 Gg/yr of NG methane for the metro area.

The city of Boston has set a goal of becoming carbon neutral by 2050 (12), and Massachusetts implemented new laws and regulations between 2014 and 2019 requiring utilities to report and repair large leaks based on their size (13, 14). A 2019 study by the Home Energy Efficiency Team (HEET) predicted that the 2018 law requiring the repair of leaks deemed "significant environmental impact" could reduce pipeline emissions by half, based on a finding that 7% of leaks emit half of all gas by volume (38). Our analysis finds that these efforts have not yet resulted in a measurable change in methane emissions, as we find no statistically significant trend over the last 8 y (Fig. 2; changes larger than 19% should be detectable given the model uncertainty).

Pipeline emissions account for 42% of total NG emissions in the bottom-up inventory; if they account for the same fraction of unknown emissions, a reduction of 50% due to policy action would be detectable by our model. All gas companies in Massachusetts have released the number of known leaks and repairs on their systems each year since 2014 (39). Notably, there has been no significant change in the number of grade 1 or 2 leaks on the pipeline system and only a slight reduction in the number of grade 3 leaks, with no sign of change after the 2018 law (*SI Appendix*, Fig. S9). Hence, from both a bottom-up leak count and our top-down analysis, it seems that new leaks are appearing in the aging Boston pipeline system as fast as old ones are being fixed. In contrast, the MassDEP bottom-up estimate indicated a 15% decrease in transmission and distribution emissions from 2012 to 2018, which was mainly due to changes in emission factors (estimated leaks per mile of pipeline, based on studies performed in other cities).

We found a strong, unexpected correlation between NG emissions and consumption in Boston (Fig. 5), a relationship which has also been demonstrated in Washington, DC (32) and Los Angeles (9, 10, 33). During the COVID-19 shutdown in April 2020, we calculated a 42% decrease in methane emissions retrieved at our lower sampling height compared to the average from April of previous years. As NG usage changed significantly in some sectors during this period, this is further evidence that NG emissions are significantly driven by consumption. This correlation between emissions and consumption is surprising because distribution pipelines, thought to be a dominant source of NG losses, are at fairly constant pressure year-round, and thus, their emissions are not expected to vary very much with consumption. Our results therefore indicate that either pipeline emissions do vary with throughput, and/or a large fraction of emissions are from other sources in which emissions are directly linked to consumption, such as space heating and other appliances in residential, industrial, and commercial buildings, transmission intersection points, flow meters, boosting compressors, or step-down and regulation. Current efforts to reduce NG emissions often target pipeline leaks; however, if a significant portion of NG emissions are not from pipelines but from consumption-driven processes, it could require changing the scope of future policy. The results also imply that policies aimed at reducing NG consumption such as shifting away from NG use in buildings could substantially reduce GHG emissions if NG is replaced with green alternatives.

To put this research in context with other cities across the United States, we compared top-down methane emissions from 12 studies across six cities with bottom-up emissions estimates based on the latest studies of pipeline, appliance, home, and commercial building losses (Fig. 7). The longest of these studies were 4 y (10) and 9 y (7); both used tracer-tracer ratios with a CO_2 or CO prior inventory. Of the studies using a CH_4 prior, the longest was 3 y (11). Across the cities, we found top-down emissions to be two to 10 times greater than bottom-up emissions estimates. The cities studied, Boston, Indianapolis, Washington, DC, Los Angeles, New York City, and Philadelphia, represent cities with both older and newer infrastructure, warmer and colder climates, and a wide range of populations. We therefore expect the range of emissions from those cities to be fairly representative of the variability across US cities. Somewhat surprisingly, though the cities with newer infrastructure, Indianapolis and Los Angeles, had slightly lower estimated emissions per capita than the cities with older infrastructure, the difference was small and within the uncertainty of the studies. This result might also point to an important role of consumption-associated emissions.

In these cities, NG emissions were estimated to account for 43 to 88% of total methane emissions. Indianapolis was an outlier at only 43% of methane from NG, because the city has a large landfill within the urban area that accounts for a large fraction of the city's emissions. These studies include tower and aircraft-based sampling as well as ground-based remote sensing methods and span cities with very different topography, wind patterns, and infrastructure. They employ model frameworks based on a variety of meteorological datasets and with methane emissions inventories, tracer–tracer methods based on CO_2 or CO emissions inventories combined with the observed CO_2:CH_4 or CO:CH_4 ratios, and aircraft mass balance. Each model may have bias due to wind speed errors, background calculations, or atmospheric mixing parameterizations, but given the diversity of approaches to the problem, it seems unlikely that such errors could account for the consistently larger emissions from top-down compared to bottom-up estimates across this heterogeneous group of urban studies. We conclude therefore that it is very likely that there are large missing sources of emissions in bottom-up methane inventories related to NG distribution and, in particular, end use.

The rate of urban NG emissions calculated by top-down studies also has important implications for the carbon footprint of NG as a fuel. An estimated 2.2% (40) of NG is lost to the atmosphere from production and transmission of the fuel before it arrives in the city. Adding to that loss rates of 1.1 to 2.5% from distribution and end use across the studies summarized here yields total loss rates of 3.3 to 4.7% associated with the full NG value chain supplying urban areas. Therefore, 30 to 50% of value chain losses for NG consumed in urban areas are from distribution and end use. For Boston, a city with older infrastructure, we calculate a total loss rate from the entire NG supply chain of 4.7%.

If the top-down emissions from these cities are representative of emissions across the country, we estimate that NG losses from distribution and end use amount to 20 to 36% of all losses from the US NG supply chain (including all end uses, not only urban; based on supply chain losses from ref. 2) and 6 to 11% of all anthropogenic methane emissions (including agriculture) (*SI Appendix*, section S8). These top-down studies thus indicate that the climate footprint of NG is larger than generally supposed, implying the need to identify and mitigate urban sources. Because methane has 86 to 125 times the global warming potential of CO_2 over 20 y and 25 to 36 times over 100 y, if 3 to 6% of consumed NG is lost directly to the atmosphere as CH_4, the greenhouse impact of NG is equivalent to that of coal (2). We note, however, that reductions in criteria pollutants emissions continues to be a benefit of NG use compared to coal or oil.

Determining the processes and source types responsible for NG emissions unaccounted for in bottom-up inventories remains a significant challenge. In Boston, the largest NG emitters from our bottom-up estimate are pipelines, transmission, and buildings, which account for 14%, 8%, and 6%, respectively, of our estimated top-down emissions; 67% of top-down emissions are unaccounted for in the bottom-up inventory. Appliance and building emissions including furnaces and boilers, which are expected to follow NG consumption consistent with this study, warrant further study to understand whether they could be a significant source of missing emissions; in particular, few studies have assessed commercial and industrial building emissions. However, as current bottom-up estimates for building losses are 0.1 to 0.3% of consumed gas (20, 21, 23), accounting for only 6% of top-down emissions in Boston (Fig. 7), these estimates would need to be increased by fivefold or more to account for a significant fraction of missing emissions.

Transmission emissions have been fairly extensively studied at a facility level, with thousands of stations assessed (e.g., refs. 41 and 42) and an estimated loss rate of 0.2% (4). The most important unaccounted-for transmission losses are likely due to "super-emitters" representing operating anomalies or failed systems; facility-level studies have shown them to be very important, and they are difficult to statistically sample using bottom-up methodology. "Super-emitters" could also play a role in missing emissions across other sectors such as losses from appliances and NG pipes within buildings. Combining building and transmission emissions, which should both correlate with consumption, bottom-up estimates are approximately sixfold lower than the 2.5% of consumed gas that is indicated by the relationship between our top-down emissions and consumption.

Weller et al. (25) assessed pipeline leaks with methane analyzers driven through four cities, covering ∼10,000 km of pipelines; their extensive coverage of roadways makes it unlikely that they missed a significant fraction of street-level emissions. One potential unaccounted-for source of emissions is pipeline gas that escapes away from streets, such as through sewage pipes or stacked vents in buildings. When we compare top-down emissions from this study to gas consumed, the intercept of the regression line implies a seasonally invariant loss of 6.4 $g/m^2/yr$, which is approximately three times higher than the pipeline emissions estimated by Weller et al. The seasonally invariant emissions in excess of those expected from Weller et al. could be due to a combination of additional pipeline emissions and appliances used year-round such as stoves and water heaters.

Our Boston top-down analysis as well as a review of studies in other cities indicate that a majority of NG emissions in urban areas are not accounted for in bottom-up inventories. Bottom-up studies have assessed each portion of the NG supply chain, and none of these studies can account for the NG emissions that we observe from top-down methods. Therefore, bottom-up studies must be missing significant emissions. Fixing fugitive NG pipeline emissions in the streets is a policy priority in many cities; however, if beyond-the-meter, transmission station, or pipeline losses away from streets make up a significant fraction of the unknown emissions, they could necessitate greater focus in policy action. Targeted, neighborhood level studies from both top-down and bottom-up perspectives will be essential to identify the emissions not accounted for in bottom-up inventories so that stakeholders can effectively focus on mitigating the largest methane emissions sources.

Data Availability. Data have been deposited in Oak Ridge National Laboratory Distributed Active Archive Center (https://doi.org/10.3334/ORNLDAAC/1982).

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Exhibit AA-4	DTE Gas Leak Detection website
Exhibit AA-5	Photograph taken 11/15/2023
Exhibit AA-6	Article: "Natural Gas Leaks and Tree Death: A First-Look Case-Control Study of Urban Trees in Chelsea, MA USA"

II. METHANE DETECTION SURVEY OF ANN ARBOR

Q. Please describe some of your recent work for the City of Ann Arbor.

A. I conducted a methane detection survey ("Methane Detection Survey") to determine the location of possible natural gas leaks and the condition of the natural gas infrastructure in the City. The results of that survey are in my Methane Detection Project Report, which is Exhibit AA-3.

Q. Please summarize how you conducted your Methane Detection Survey.

A. I drove each side of every accessible roadway in Ann Arbor with a Picarro G2301 3-gas mobile analyzer to perform a cavity ringdown spectrometer ("CRDS") methane survey of the 307 miles of public roadways in the City. I also conducted a visual vegetation survey to identify dead, dying, and/or missing municipal trees, which are signs of natural gas leakage.

Q. What is the purpose of a CRDS methane survey?

A. The mobile analyzer detects and maps methane in parts per billion, so one can look at the survey results and identify locations with elevated methane levels, which are typically natural gas leaks emanating from the natural gas distribution system.

Q. Did the CRDS methane survey performed in Ann Arbor identify any locations with elevated methane levels?

A. Yes. The survey detected 165 locations with elevated methane levels in the City.

Q. What steps did you take after identifying the 165 locations with elevated methane levels?

A. I selected 50 of the 165 locations to perform further testing. At each of these 50 locations, I used a Picarro G4301 Scouter portable CRDS analyzer to pinpoint the source of the methane that was detected in the mobile survey. I then documented each verified leak I discovered, graded the leaks for safety, determined the leak migration area of each verified leak using standard bar hole testing with an industry standard Bascom-Turner Combustible Gas Indicator calibrated on the first day of each month in operation, and noted any methane that had migrated to the root zones of trees.

Q. Why do you believe that gas leaks were the likely source of the elevated methane levels in these locations?

A. Each of these locations was in close proximity to gas distribution infrastructure with no other apparent source of methane (such as landfills, ruminant animals, failed septic systems, failed sewer systems, or other potential source of methane).

Q. In total, how many verified gas leaks did you identify at these 50 selected locations?

A. At these 50 selected locations, I identified 50 total gas leaks: two that are Grade 2 leaks and 48 that were Grade 3 leaks.

Q. Do you believe these 50 leaks are the only gas leaks in the City?

A. No. Due to time limitations, I was unable to perform further testing on 115 of the 165 locations where elevated methane levels were detected. It is likely that gas pipelines are the source of many of those leaks, but at this time I have not done enough research to draw a conclusion about what is causing the elevated methane levels at those 115 sites.

Note that the DOE Billion-Ton Report, USDA Census of Agriculture, EPA CWNS, and LMOP Database, among other data sources, have been updated since the 2019 AGF RNG study.

This RNG feedstock inventory does not estimate resource availability—in a competitive market, resource availability is a function of factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized given the necessary market considerations (without explicitly defining what those are), outlined in Section 2.3.4.

2.2.2 RNG from Methanated Hydrogen (P2G)

ICF limited the methanated hydrogen feedstocks considered in this study to dedicated renewable electricity and select sources of carbon oxides. ICF's scope considered dedicated electricity produced from wind, solar, and nuclear resources. Furthermore, ICF assumed that the carbon dioxide sources for methanation would either be biogenic (e.g., from an ethanol production facility), carbon capture from industrial processes, or via direct air capture. This is not an exhaustive list of feedstocks for RNG from P2G (for example, curtailed renewable electricity may not always be precluded as a feedstock for P2G in practice) but these feedstocks were deemed as reasonably feasible resources to consider in a prospective future methanated hydrogen RNG supply within the limitations of this study.

2.3 RNG Technical Potential

ICF estimated the technical resource potential for RNG production using the three production pathways outlined previously. Section 2.3.1, below, outlines changes from the 2019 AGF Study, whereas Section 2.3.2 and Section 2.3.3 cover the RNG technical potential via anaerobic digestion and thermal gasification pathways, respectively. Those two subsections are broken down by feedstocks. The RNG technical potential from these pathways are linked to the biomass inventory that ICF developed for each respective feedstock (see Section 2.2). In Section 2.3.4, ICF turns to its approach to estimating RNG technical potential from the P2G/methanation pathway. ICF developed an approach whereby renewable hydrogen was considered the limiting factor in the P2G/methanation pathway for RNG technical potential.

The technical potential estimates shown in the figure and table below, in units of tBtu/y, reflect the total maximum RNG that could be produced from the 100% utilization of all feedstocks, irrespective of practical, economic or market constraints on feedstock availability or production capacity. The technical potential is a theoretical maximum of RNG production potential and is a starting point to create specific supply scenarios, rather than a realistic supply scenario in and of itself. A variety of technical and economic constraints are applied to develop these scenarios, which are discussed in more detail in the following subsections below.

Figure 4 summarizes the maximum theoretical RNG potential for each conventional biomass-based feedstock and production technology across the United States. This total represents over 16,000 trillion British thermal units per year (tBtu/y)[7] of natural gas per year. Table 3 that follows below breaks down the maximum technical potential for the eight feedstocks by census region.

ICF notes that the maximum technical potential from P2G is not included in the following figure and table as it does not face similar or consistent production constraints compared to the eight biomass-based RNG feedstocks.

[7] 1 tBtu is equivalent to about 1 billion cubic feet (BCF) of natural gas.

Pipeline Gas and Liquid Fuels

Pipeline Gas

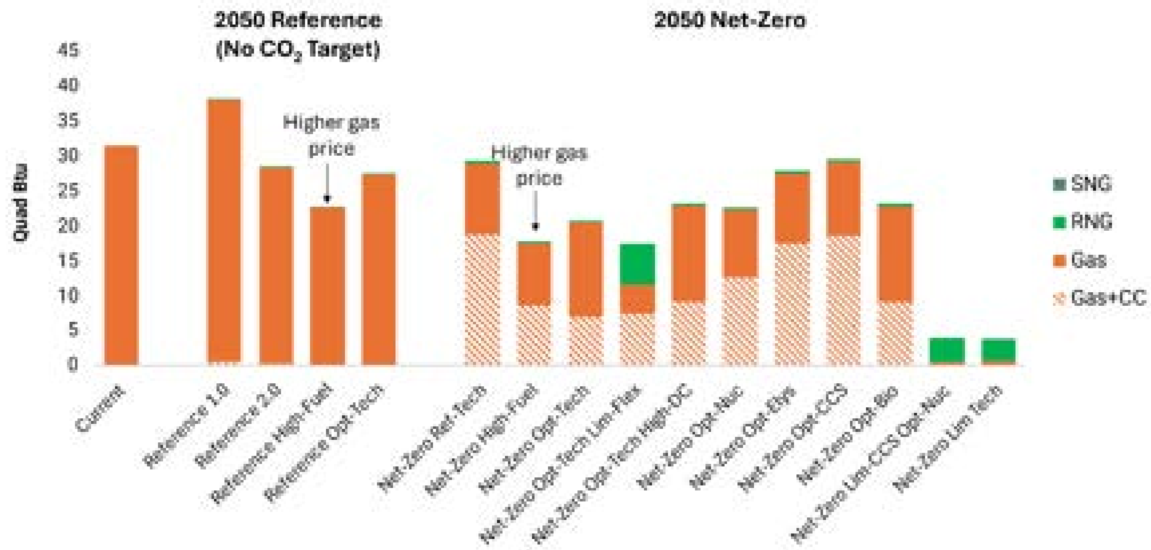

Figure 39. U.S. Total Pipeline Gas Demand in 2050. See Table 1 for scenario definitions. CC = carbon capture; RNG = renewable natural gas; SNG = synthetic natural gas.

The extent and type of pipeline gas demand varies significantly across scenarios (Figure 39). In the Reference 1.0 scenario, which excludes IRA incentives and other updates, total gas demand in 2050 is higher than current demand. In all other scenarios, gas demand declines over time but remains significant in all cases except the limited net-zero scenarios without CCS. As would be expected, the scale of demand is sensitive to the gas price, as higher fuel prices imply greater shares of renewables and electrification. Comparing the Reference 2.0 scenario to the Net-Zero Ref-Tech case, gas demand in 2050 actually increases slightly in the net-zero scenario, albeit with a much higher share used with carbon capture. In most cases, the pipeline gas mix remains primarily composed of fossil-based natural gas, expect in cases with limited CDR flexibility where renewable natural gas (RNG) is an important low-carbon substitute.

Importantly, gas capacity for electric generation increases significantly relative to today and is less sensitive to scenario variation (Figure 40). In most net-zero cases, the amount of gas capacity is similar to that in the reference scenarios, again with a higher share deployed with carbon capture. As discussed in the Electric Generation and Capacity section, the need for gas capacity scales with its peak requirements for gas delivery rather than its annual demand for generation.

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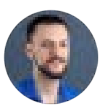
WASTEDIVE

How the EPA's Renewable Fuel Standard program changes could be a boon for landfill and AD operators

The program's biggest change to date would set long-term renewable natural gas targets, add credits for powering electric vehicles and much more. WM, Republic Services, Anaergia and others weigh in.

Published Feb. 16, 2023



Cole Rosengren
Managing Editor

Courtesy of Waste Management

Proposed changes to the federal Renewable Fuel Standard program could be a financial boost for operators generating energy from landfills and anaerobic digesters, depending on how the final details shake out.

The RFS was created in 2005 as part of an amendment to the Clean Air Act, with a goal to reduce transportation emissions by setting targets for the use of renewable fuels to "replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel." Refiners or importers of gasoline and diesel fuel must obtain credits called renewable identification numbers (RINs) in order to meet annual volume targets set by the U.S. EPA.

Waste facility operators have profited from those RIN credits, but political complications around setting the annual volume targets has led to fluctuating values. Now, for the first time, the EPA — along the Department of Energy and Department of Agriculture — is setting multiyear volume targets through 2025, as opposed to annual updates. EPA's recent proposal would also establish an eRIN program targeted at electric vehicles, along with other notable changes.

The agency, which aims to finalize plans in June, received numerous suggestions during a recently-closed public comment period.

Volume growth

Compliance in the RFS program is driven by fossil fuel companies either blending renewable fuels into their products or purchasing RINs to meet renewable volume obligation (RVO) targets. The annual RVOs directly affect RIN values.

EPA's latest calculation projected a 13.1% year-over-year increase in RNG volumes, based on recent market conditions, for RINs derived from cellulosic biofuel for compressed or liquid natural gas used in transportation. Industry groups are pleased to see the EPA expanding the program but feel its targets miss the mark.

"We're concerned with the fact that the rules only use a growth rate that looks back one year," said Sam Wade, director of public policy for the RNG Coalition, citing pandemic and supply chain effects. The group, which is generally supportive of the program's expansion, suggests a 30% growth rate that Wade said is "more realistic and reflects better what the RNG industry could do in this space."

The RNG Coalition, which reports 276 active RNG sites in North America, is advocating for a regulatory mechanism that could automatically adjust annual RVO targets, and its comments cited numerous examples of expansion. On top of existing state and federal incentives, including the 2022 Inflation Reduction Act, the sector is seeing significant ESG-driven investment. Another 114 projects are under construction, with 150 more planned.

The National Waste & Recycling Association and Solid Waste Association of North America called for a "minimum" 30.4% growth rate, citing $2 billion in planned RNG investments by the waste industry's top three companies alone.

WM recently increased its planned RNG spending by $390 million over the next three years — citing the RFS and other federal incentives. In prepared testimony for a January RFS hearing, Senior Counsel and Director of Regulatory Affairs Michael Jensen said these factors have "created a favorable environment for our sector to explore additional investment in RNG and biogas production infrastructure."

Given these trends, some companies hope to encourage a shift in the EPA's thinking.

"We're seeing increasing value of biogas assets now with multiple paths for monetization," said Noah Kaye, a senior research analyst at Oppenheimer. "We're hearing that some players are certifying their construction pipelines with EPA in an effort to boost the projections for RNG generation."

Sources say the agency must strike a complicated balance. Raising the RVO targets too much could risk litigation from energy companies, which has occurred before. Setting them too low could crash the RIN market.

"They need to err on the side of being aspirational and there are a lot of reasons, especially within the last 12 months, to support being more aspirational," said Patrick Serfass, executive director of the American Biogas Council. His group is advocating for a minimum 20% growth rate, saying the current proposal "seems out of touch with even slow pandemic years."

EPA Administrator Michael Regan gives remarks at a Washington, DC. event on new national clean air standards for heavy-duty trucks, next to an electric refuse vehicle, on Dec. 20, 2022.
Anna Moneymaker via Getty Images

Enter eRINs

The potential to generate RINs from renewable electricity systems in 2024 is a long-awaited update that may be especially relevant to the waste industry. Yet the agency's proposal to have light-duty EV manufacturers, rather than energy producers, manage the eRIN credits has elicited ample pushback.

EPA sees benefits from limiting the number of parties involved in this new program. Biogas trade groups and others don't think the move to limit control of eRIN credits is rational and are concerned about one major EV player — Tesla — having outsized influence. Comments have also been shared about how the regulations could affect landfills that generate electricity as well as RNG.

Still, observers say the program would be beneficial for landfill operators because they could share in the RIN value, like they would with a third-party RNG developer. Depending on how final eRIN volume targets are calculated, and how the market responds, some landfill operators could even end up receiving a larger share of the eRIN value.

According to ABC, around 2,000 of the estimated 2,300 operating biogas systems in the U.S. produce electricity. Within the landfill sector, it's also more common for gas systems to generate electricity than RNG.

WM has dozens of these operations in place, with its first project dating back to 1987. The company recently announced it will keep two sites in this category — rather than converting them to RNG sites as planned — due to the proposed RFS changes.

"This, we believe, will be a significant revenue stream for us long term. It's a great example of our ability where we have owned these facilities and invested in them and retained the value. Now we're in a position to optimize the value with this pathway," said Chief Sustainability Officer Tara Hemmer during a recent earnings call.

Republic Services also sees potential from eRINs — while noting similar industry concerns about logistics — but wants the EPA to go further. The company, which has ambitious fleet electrification targets, said excluding medium- and heavy-duty EVs from the program is "a significant oversight and missed opportunity."

During a Wednesday earnings call, CEO Jon Vander Ark said the "vast majority" of Republic's landfill gas projects currently generate electricity and could benefit from the eRIN program, especially if they are used to power the company's fleet. He said that BP, a joint venture partner on many upcoming landfill gas projects, was similarly "open-minded" about the potential.

"We've got option value with eRINs coming online," said Vander Ark. "We see it as, over time, a benefit for us because it'll have two pathways."

While large competitors, such as WM, are still more focused on CNG vehicles that are already part of the RFS system, industry adoption of EVs is expected to grow substantially in the future.

Yet another change could come if the EPA eventually decides to include biomass facilities in the eRIN program. Covanta is among those asking it to reconsider the exclusion of facilities such as its mass burn combustion sites from the upcoming expansion. In comments, it said that doing so would "be consistent with the feedstock neutral intent of the Clean Air Act" and help remedy "EPA's inconsistent treatment of landfill biogas and WTE."

Food waste expansion

While all of these proposed changes will be important to landfill operators, they also have implications for anaerobic digesters. Currently, digesters that handle streams such as wastewater and manure generate higher-value RINs (via a code based on feedstock types). But if food waste gets included then the entire project can only generate a less-valuable RIN type. Now, under a proposed update, the EPA would have more nuance in the credits for blended feedstocks.

This could be a notable shift for local governments or companies focused on codigestion, such as Anaergia. Chief Operating Officer Yaniv Scherson said he's glad to see the agency "setting a precedent and a pathway for blending of feedstocks," calling the current rules "a barrier for codigestion, which is a big synergy in the industry."

Groups such as ABC similarly believe the proposed RFS changes could boost the amount of food scrap recycling.

"The combination of eRINs, plus being able to add food waste without taking a discount in your credits, those are the two really new things that could potentially change the waste industry," said Serfass.

Looking ahead

As the EPA works to finalize its updates for this highly complex program, it will also be grappling with numerous other issues raised by industry groups around compliance timelines, modeling estimates, storage requirements and more. It must also contend with critiques from environmental groups, among others.

Beyond this possible regulatory boost, trade groups and companies envision an even bigger future for RNG in what's known as the voluntary market.

As ESG-driven companies look to reduce their emissions from energy consumption for heat or power, RNG demand has grown. Long-term offtake agreements are gaining prominence, as reflected in comments from BP after its acquisition of Archaea and in recent updates from landfill companies. As one example, Anaergia touted an agreement with Canada-based Irving Oil to purchase RNG from its digester in Rhode Island.

"What's really going to put jet fuel into the RNG industry is the voluntary market," said Scherson, predicting that within five years there will be much less focus on RIN values. "This program will become less relevant to the RNG industry, materially less relevant."

Other trade groups and companies agree that non-transportation demand for RNG is set to grow significantly. In the meantime, Kaye said RNG values in the regulatory compliance markets still tend to be higher, though he expects more convergence over time.

"What this all means for waste companies' investment plans, capital allocation strategies and economics is something investors are closely watching," said Kaye. "The picture is fluid, but it's positive."

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WASTEDIVE

DIVE BRIEF

Biogas groups, lawmakers jockey for changes as EPA nears final rule on eRIN market

Published May 11, 2023

Jacob Wallace
Reporter

Courtesy of Archaea Energy

Dive Brief:

- A coalition of biogas industry groups that include the RNG Coalition and American Biogas Council urged the U.S. EPA to finalize a program that is slated to include the fuel in a lucrative new credit market in a letter sent to the agency last week. The EPA must set biofuel quotas under the Renewable Fuel Standard, which governs the RIN market, by June 14, but is reportedly considering punting its eRIN decision as a result of pushback.
- The proposed eRINs program would generate credits from renewable electricity systems like biogas to power electric vehicles. But Republicans on the House Energy & Commerce Committee sent a letter to the EPA saying the program "inserts uncertainty into the transportation fuels market."
- Meanwhile, Democrats have sent their own letter urging the inclusion of waste-to-energy facilities if the eRIN program is adopted. The letter was signed by 10 lawmakers, all from states

like Florida, California and Connecticut that currently have waste-to-energy facilities.

Dive Insight:

If passed, the eRIN proposal has the power to give landfills, anaerobic digesters and other biogas producers a larger piece of the credit market as it hastens the transition away from petroleum-based fuels.

In their letter, industry groups said that implementing eRINs in the EPA's newest rulemaking is complementary to other agency activities designed to electrify the U.S. vehicle fleet and consistent with previous actions to create a biogas electricity pathway.

The rule EPA finalizes on June 14 is scheduled to go into effect at the start of 2024.

"This long-awaited opportunity is timelier than ever," the groups wrote.

Republicans expressed skepticism that the EPA had the authority to create a new branch of the Renewable Fuel Standard related to electricity markets rather than traditional fuels, and said they'd prefer such a program be implemented through legislation.

Their letter comes amid Republican opposition to expanded electric vehicle tax credits and other climate-related programs passed and signed into law by President Biden. Democrats, meanwhile, have looked to expand on the Biden administration's efforts to reduce waste going to landfills.

The letter sent by Democrats in support of adding waste-to-energy facilities to the eRIN market notes that such facilities divert material that would otherwise be landfilled and argue their inclusion would support efforts to reduce greenhouse gas emissions.

“We urge the EPA to align its final rule with the Biden Administration’s commitment to reducing greenhouse gas emissions and not incentivizing landfilling. The EPA should ensure equal treatment for WTE,” the lawmakers wrote.

The EPA could split off its decision on eRINs from its June 14 rulemaking, Reuters reported last week. That deadline was set as part of a settlement agreement with biofuel trade association Growth Energy requiring the EPA to set Renewable Volume Obligations on a regular timeline.

The RVOs apportion a certain amount of RIN credits to biofuels, something industry groups previously said they are not getting enough of in the proposed rule. They say the EPA is undervaluing the rapid growth of the biogas industry.

The eRINs would be a boost to biogas on top of those traditional RINs, and delaying or halting implementation of eRINs could have a negative effect on the growing industry, biogas groups said. Even if groups don’t get the expanded credit volumes they’re pushing for, they’d rather see the rule get finalized then get put on hold, Patrick Serfass, executive director of the American Biogas Council, said in a companion letter to the EPA.

“We do not believe this to be the time to allow the pursuit of a perfect regulatory policy structure to get in the way of a very good and necessary program,” Serfass wrote.

Key Findings ➜ Low-Carbon Alternative Fuels

Zero- and low-carbon alternative fuels, such as hydrogen, renewable natural gas (RNG), renewable diesel, sustainable aviation fuel (SAF), and synthetic fuels, are an important complement to electrification in the State's energy transition strategy. Zero- and low-carbon alternative fuels are particularly useful in helping to decarbonize hard-to-electrify end uses where continuing to use liquid or gaseous fuels may be necessary, for example in agriculture and industry, marine, aviation, and long-distance trucking. Low-carbon alternative fuels could also support electric system reliability by supplementing electricity supply during peak periods, such as to meet peak winter heating demand. This chapter provides an overview of the State's approach to low-carbon alternative fuels, outlines major initiatives underway, and recommends continued and additional actions.

- **Low-carbon alternative fuels are an important complement to electrification in the State's clean energy transition strategy.** In cases where electrification and zero-emissions solutions are impracticable due to technological, safety, cost, or reliability constraints, these fuels should be prioritized for end uses where they can deliver the greatest greenhouse gas (GHG) emissions reductions with the lowest cost and environmental impact. The deployment of low-carbon alternative fuels should also ensure net reductions in co-pollutant emissions and avoid disproportionate impacts on disadvantaged communities associated with such emissions. Since supply of these fuels will be limited, analysis indicates that low-carbon alternative fuels are best directed toward targeted and high-impact applications in transportation, supplemental heating, agriculture and industry, and the power sector—areas where full electrification may not yet be practical to maximize environmental benefits and GHG emissions reductions.

- **Alternative fuels should be carefully managed to realize GHG emissions reductions.** GHG emissions associated with the feedstock, production, transportation, storage, and combustion of low-carbon alternative fuels should be considered. To maximize global GHG emissions reductions, New York State prefers waste-based feedstocks for alternative fuel production. To further maximize in-state benefits and achievement of the State's climate goals, the State prefers fuels and feedstocks sourced within the state. Recognizing the supply limitations, the State remains open to regionally sourced and other low-impact feedstocks to advance global GHG reduction.

- **Both life cycle analysis and Climate Act accounting of GHG emissions from low-carbon alternative fuels should play a role in the design and development of programs and policies.** Life cycle analysis should be used in policy development to evaluate and compare GHG emissions reductions associated with different feedstocks, fuels, and end uses and to calculate emissions reductions relative to a business-as-usual scenario. The Climate Act accounting framework should be used when calculating emissions impacts that relate to measuring progress toward Climate Act goals.

- **Alternative fuels deployment should be strategic to realize co-pollutant emissions reductions, especially in and near disadvantaged communities.** While reducing global GHG emissions is important, any potential net increase in local co-pollutant emissions from the use of alternative fuels should be considered and avoided wherever possible. To maximize co-pollutant emission reductions, electrification and other zero-emission solutions should be prioritized unless there are specific technological, safety, or reliability challenges.

- **Policies and tracking systems should balance rigor with feasibility to accelerate alternative fuels deployment while ensuring credible emissions reductions.** The integrity of GHG emission reduction claims depends on transparent, robust, and credible tracking of alternative fuel attributes; however, systems should be designed to avoid excessive administrative burdens that could stifle deployment and prevent emissions reductions. The delivery of fuels to New York State for use within the state is of critical importance. New York State should carefully consider methods to appropriately and accurately measure emissions reductions and should consider designing an attribute tracking process that includes additional considerations, such as valuing unique aspects of certain fuels or technologies, avoiding land use change, or avoiding undesired feedstocks or origin locations.

- **To catalyze low-carbon alternative fuels markets to meet future demand, policy, regulatory, and market interventions—such as mandates, market-based mechanisms, and incentives—will likely be needed.** Demand is likely to outpace the current limited supply of these fuels, underscoring the need for supportive policies and regional market development to expand cost-effective production to increase availability. Additional market structures or mechanisms may also be needed to align price structures to realize the needed supply of low-carbon alternative fuels and should be evaluated against any potential consumer cost increases resulting from these policies.

- **To meet State policy goals, a limited amount of alternative fuels will need to be produced, transported, and used in the broader energy system.** To minimize costs and other impacts, existing infrastructure should be leveraged for the transport and storage of pure or blended alternative fuels wherever it is safe and technologically and economically feasible. In cases where existing systems are incompatible or insufficient, limited new, fuel-specific infrastructure may be needed to connect supply with areas of demand. New York State does not currently support the blending of hydrogen into the existing natural gas pipeline system due to safety, system integrity, and indoor air quality concerns, as additional research is needed to understand such use.

4. Themes and Recommended Actions

4.1. End-Uses of Alternative Fuels

Low-carbon alternative fuels will be an important and complementary decarbonization strategy alongside electrification in a variety of settings, such as supplemental heating and difficult-to-electrify end-uses. It is important to consider that the supply of alternative fuels will be limited due to regional competition and supply constraints on organic feedstocks used to produce most alternative fuels as well as the supply of clean electricity for hydrogen production. Electrification typically delivers greater health and GHG emission reduction benefits at lower cost compared to alternative fuels. Therefore, electrification should remain the State's primary decarbonization solution. The use of low-carbon alternative fuels should be prioritized for end uses to maximize GHG emissions reductions, minimize costs, ensure net co-pollutant emission reductions, and avoid localized co-pollutant emission impacts. The development and use of alternative fuels should support the State's long-term GHG reduction targets and long-term energy vision. Some fuels, such as biodiesel, may incrementally decrease emissions relative to fossil fuels, but would not enable the deep emission reductions required to meet the State's goals. Renewable diesel, for example, provides near-term decarbonization in the transportation sector without extensive buildout of infrastructure while allowing the production infrastructure and feedstock supplies to be redirected toward SAF in future years as heavy-duty transportation electrification develops. Similarly, investing in hydrogen production using today's electric grid can deliver incremental GHG emissions reductions, recognizing that electricity emissions will continue to decline as more renewable generation is added to the mix.

Recommendations

- 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 emissions.
- The use of alternative fuels should be oriented such that technologies for near-term decarbonization can effectively transition to longer-term solutions as technologies and markets develop, consistent with long-term GHG reduction targets.

4.2. Prioritization of Alternative Fuels

Given the limited supply of common feedstocks, the long-term considerations for fuel use described above, and the GHG and co-pollutant concerns described below, the development of long-term fuel infrastructure should prioritize certain fuel types. There are several factors that drive this prioritization:

- **Maximizing the use of New York's waste resources**. Utilizing New York State waste resources and waste feedstocks avoids unnecessary emissions in the waste sector, further reducing GHG emissions and reducing the need for purpose-grown feedstocks that have increased production emissions and uncertain land use impacts. NYSERDA's recent *Feasibility Study for Renewable Fuel Production from Waste Resources in New York State* evaluated the potential fuel production from in-state waste feedstocks, focusing on SAF production and fuels typically coproduced with

- Similarly, any environmental impacts of biofuels on local, disadvantaged communities (DACs) should be minimized where possible. Certain production pathways may deliver greater emissions reduction than others, although estimates remain uncertain. Careful assessment of avoided emissions benefits from waste management, and additional emission impacts from induced LCUs, is necessary to evaluate the full benefits of alternative fuels. In addition, in-state and imported fuels may offer different levels of contribution toward Climate Act emission reduction targets, which must be balanced with the State's other priorities.

Based on this review, the report outlines strategic guidelines for how New York State can direct research, development, and policy to maximize the benefits of alternative fuels, especially in decarbonizing hard-to-abate sectors, while enhancing reliability, resilience, and affordability of the energy system.

Strategic Element 1: Regulations and Incentives

New York State should consider regulatory and market incentives to facilitate and transform today's nascent alternative fuel markets. These measures should (1) optimize the use of limited feedstock effectively between different alternative fuels for their production, and (2) prioritize the use of these fuels for high-value end uses.

Current markets for low-carbon alternative fuels in the U.S. are nascent, with small volumes of low-carbon alternative fuels currently produced. While biofuel production has grown in recent years due to federal and State policies and tax incentives, biofuel volumes are still quite small relative to their traditional fossil fuel equivalents.[1] For example, in 2023, the energy output of fossil gasoline diesel produced was over 50 times greater than the combined energy output of all the renewable diesel and biodiesel produced in the U.S.[2, 3]

To convert end uses and develop the necessary production capacity, transportation, and markets for low-carbon alternative fuels, New York State will require significant policy, regulatory, and market initiatives to guide the development of supply and demand for these fuels. New York State can leverage the potential feedstocks and supplies within the State and region and may be able to import alternative fuels from more distant sources. However, as detailed in Section 2.2, organic feedstocks needed to produce many low-carbon alternative fuels are quite limited relative to current fossil fuel usage. Neighboring states and Canadian provinces are also pursuing similar strategies to meet their own climate and energy policy goals, significantly increasing competition for available supplies.

Over time, local, regional, and potentially national and international markets for low-carbon alternative fuels are likely to emerge, even if overall volumes are smaller. These markets may resemble current fossil fuel markets due to similar drivers, such as high value, ease of transportation, location of supply versus demand, differing product costs). Once developed, these broader markets can help direct both feedstocks and the low-carbon alternative fuels themselves to the highest value uses in New York State and elsewhere. The State should help shape the development of these markets and coordinate its policies and regulations to align state-level supply and demand with broader regional and national efforts.

Strategic Element 2: Alternative Fuel Infrastructure

New York State will need to develop infrastructure to support a low-carbon alternative fuels sector. Where feasible, the State should optimize and repurpose existing infrastructure to mitigate potential costs and avoid environmental and community impacts from new construction. Collaboration with neighboring states and provinces to plan and develop this infrastructure can further reduce these impacts, especially as alternative fuel markets extend well beyond New York State borders.

New York State should also consider developing distribution infrastructure to connect low-carbon alternative fuel supplies with demand. Where fuels are not drop-in replacements for fossil fuels, New York State may need to incentivize the production and deployment of end-use equipment that accommodates these alternatives.

The State already has an extensive array of existing energy infrastructure, including natural gas and petroleum pipelines, fueling depots, rail and marine transport, designed and built around connecting today's (largely fossil) fuel supplies with demand. As New York State transitions toward a decarbonized future, it may retrofit or repurpose portions of this infrastructure for alternative fuel applications. However, as discussed in Section 3, this will require addressing certain technical and safety challenges. In some cases, new or upgraded infrastructure may also be necessary, for example, when low-carbon alternative fuel supply and demand differ geographically from existing current fossil fuel patterns; transportation infrastructure needs may change.

In addition, New York State may need to develop new "first-mile" infrastructure to connect new sources of energy feedstocks, such as crop waste or energy crops from agricultural regions, to production facilities. Where repurposing existing infrastructure is not feasible or economic, coordinated regional infrastructure planning with neighboring states and provinces may help reduce the need for new infrastructure, limiting costs and other negative impacts.

Strategic Element 3: Emissions

While alternative fuels typically emit fewer GHGs and copollutants than conventional fuels, they are not entirely emissions-free. New York State should quantify, track, and control these emissions at (1) the global scale, to maximize GHG reduction benefits, and (2) the local scale, to ensure that disadvantaged communities (DACs) and environmental justice (EJ) communities are not disproportionally affected by localized air, water, and land use impacts. New York State may also consider establishing standards, incentives, and renewable fuel attribute markets, in coordination with neighboring regions, to improve accounting accuracy, transparency, and transaction efficiency between producers and suppliers.

Alternative fuels' potential GHG, co-pollutant emissions, and land use impacts warrant further consideration and evaluation by New York State. Most alternative fuels still emit GHGs during combustion, sometimes at levels comparable to fossil fuels. Alternative fuels also produce co-pollutants during combustion, which will need to be quantified, tracked, and controlled to understand and limit local air quality impacts, particularly in relation to DACs and EJ communities. While total fuel demand is expected to decline, reducing total co-pollutant emissions, local concentrations must still be considered.

The production of alternative fuels also has land use implications that New York State should work to understand and address with policy solutions. For example, growing energy crops may divert agricultural land and resources from food or animal feed production, or require the conversion of new agricultural land to meet feedstock demand. In addition, considerable variability and uncertainty are involved with the commonly applied life-cycle analysis (LCA) methods, most specifically regarding land use impact and emissions. Establishing emissions standards (GHG and co-pollutants) and environmental impact standards will be important for the State, followed by the development of regulations or measures such as siting and permitting requirements and life-cycle analysis certification mechanisms.
As an interim strategy, the State may encourage blending alternative fuels with conventional fossil fuels (where feasible). This approach can reduce emissions in the near term while facilitating development of both supply and demand, which will be particularly useful in hard-to-decarbonize sectors and will rely on alternative fuels in the long run.

In this context, New York State may also benefit from developing renewable attribute markets in coordination with neighboring states to allow for ease of transactions and to encourage the development of renewable fuel markets that create the proper emissions and environmental incentives.

Strategic Element 4: Coordinate with Other Jurisdictions

New York State should engage and collaborate with government and market efforts in other jurisdictions to scale low-carbon alternative fuel markets. This coordination can help optimize feedstock supply, develop new infrastructure, and establish emissions and environmental attribute tracking and accounting systems.

New York State is not alone in addressing the challenges and opportunities of low-carbon alternative fuels. State, federal, and international initiatives are already underway to support their large-scale deployment. For example, New York State offers incentives to encourage the development and adoption of these fuels, such as the Alternative Fuel Infrastructure Tax Credit and Heavy-Duty Alternative Fuel and Advanced Vehicle Purchase Vouchers program.[4, 5] At the federal level, incentives include vehicle subsidies, funding for regional clean hydrogen hubs, and the U.S. Environmental Protection Agency's (EPA) Renewable Fuel Standard (RFS). Internationally, more than 65 countries, including the U.S., have published national hydrogen strategies and roadmaps.[6]

Several neighboring states and Canadian provinces that have decarbonization goals are similarly evaluating the role of alternative fuels in their decarbonization strategies. Massachusetts anticipates using a mix of alternative fuels and e-fuels[7] across sectors to serve nonelectrified demand.[8] Énergir, the largest natural gas distributor in Quebec and Vermont, plans to blend RNG and hydrogen into its gas systems.[9] Furthermore, New Jersey currently consumes approximately two-thirds of the renewable diesel imported to the East Coast.[10]

As the alternative fuel ecosystem evolves and becomes more mainstream, New York State should coordinate these and other policies across jurisdictions to ensure consistency and effectiveness. Coordinating with other states, provinces, the federal government, and even international governments will help harmonize with others in the region, nationally, and even globally.

Such coordination can facilitate the creation of consistent fuel product designations and specifications, emissions measurements and requirements, and environmental attribute definitions and tracking. This collaboration will facilitate the development of broad geographic markets, effective regional fuel transportation systems, and encourage both supply and demand growth for alternative fuels, ensuring their availability at scale in the longer term, at reasonable costs, and with credible emissions benefits.

  - Ensure that clean electricity used for alternative fuel production, such as hydrogen, does not divert from easy-to-electrify applications in buildings and transportation.

- **Plan and invest in fuel infrastructure strategically.** As demand for low-carbon alternative fuels grows, the State should ensure that it has sufficient delivery infrastructure to move alternative fuels from production locations to demand areas. To reduce costs and minimize impacts:
  - Leverage existing infrastructure where possible, accounting for technological, economic, and safety considerations.
  - Where existing infrastructure cannot be repurposed, develop limited new alternative fuel infrastructure to connect supply and demand for alternative fuels.
  - Recognizing that energy infrastructure is regional, coordinate with neighboring states and provinces to align investments and develop a regional infrastructure strategy for low-carbon alternatives.

- **Establish robust life-cycle GHG emissions accounting standards** for biofuels that fully reflect all life-cycle emissions, including LUCs and upstream inputs. These standards should:
  - Develop GHG emissions accounting standards for biofuels that appropriately take into account all relevant stages of their life cycle when determining emission reduction benefits.
  - Ensure that policies, programs, and regulations appropriately reflect the requirements for alternative fuels and prioritize GHG emissions reductions while minimizing co-pollutant emissions.
  - Avoid increases in local GHG and copollutant emissions from the use of low-carbon alternative fuels, even when total life cycle GHG reductions are achieved.
  - Prioritize electrification unless specific technological, safety, or reliability challenges justify the use of low-carbon alternative fuels.

5.2 Supply and Demand

New York State can actively incentivize the use of low-carbon fuels through levers, including developing a regional low-carbon fuels market, providing incentives to optimize the production of key fuels, creating a centralized entity to offer market guidance, and supporting the deployment of end-use equipment.

Regional low-carbon fuel markets play a key role in supporting early market development. By implementing these markets on a regional scale, states can improve efficiency, facilitate price formation, and enable the sharing of regional feedstocks. As discussed earlier, the LCFS in California, Oregon, Washington, and British Columbia have already driven a shift from fossil to low-carbon alternative fuels in those jurisdictions. As a result, the West Coast has become the leading consumer of renewable diesel. New York State can consider adopting similar fuel standards along with neighboring states to grow demand in the Northeast and stimulate the development of local markets. This approach will help ensure that the production capacity aligns with anticipated demand. Regional market formation can support a smooth transition by integrating alternative fuels markets into existing fossil fuel markets.

Regional markets can further assist by implementing gradual blending standards, which incentivize early development of nascent fuel markets. These blending standards offer predictability and can target specific sectors or end uses. Once markets and infrastructure for the fuels mature, the State can redirect blends of low-carbon alternative fuels to other end uses as needed.

State policy also plays a critical role in ensuring that market development aligns with long-term strategic goals. Natural market forces may steer the use of alternative fuels in directions that conflict with New York State's energy vision. As discussed, limited biological feedstocks may flow toward lower-cost, but less strategic, applications that outcompete more targeted applications, especially during the early stages of market development. Wastewater, for instance, may be able to produce RNG at a lower cost than SAF 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 SAF or renewable diesel does. By prioritizing electrification and other zero-carbon solutions (e.g., hydrogen) in easy-to-electrify end uses, the State can preserve scarce low-carbon alternative fuels for hard-to-electrify end uses. To support this, New York State should establish regulations and enforcement mechanisms that prevent the use of unverified or unverifiable feedstocks in the production of low-carbon alternative fuels.

The creation and development of these markets will involve multiple interconnected components, from producing fuels and connecting supply with end users, to verifying emissions reductions and scaling end-use technologies. New York State can take the lead by establishing a central authority responsible for coordinating these efforts and ensuring that market development aligns with State goals and standards. This organization can provide technical guidance, track emissions reductions, administer incentives for market participants, provide relevant market data (such as available supply and pricing), and provide education materials for the public.

5.3 Infrastructure

The demand for low-carbon alternative fuels in New York State is anticipated to be lower than the current demand for fossil fuels because a significant share of today's fossil fuel end uses will be electrified. As a result, the scale and capacity of infrastructure required to produce, store, and distribute alternative fuels

Heat Pump Emissions

Inputs

Baseline Year	2025

Equipment Lifetime (yr)

		Standard Efficiency (Years)	High Efficiency (Years)
Heat Pump HVAC	Central ccASHP	15	15
	Ductless ccASHP	15	15
	GSHP	15	15
	A2W HP	15	15
	Propane DFHP	15	15
	Gas DFHP	15	15
	Gas Abs. HP	15	15
Heat Pump WH	Individual Storage HPWHs	15	15
	Large Central HPWHs	15	15

Electricity Consumption

		Electricity Consumption per Year (Standard Efficiency)	Electricity Consumption per Year (High Efficiency)	Units
Heat Pump HVAC	Central ccASHP	6820.32	6732.44	kWh/yr
	Ductless ccASHP	6466.57	6467.67	kWh/yr
	GSHP	6463.32	5748.83	kWh/yr
	A2W HP	7200.63	6375.44	kWh/yr
	Propane DFHP	1522.57	1434.69	kWh/yr
	Gas DFHP	1522.57	1434.69	kWh/yr
	Gas Abs. HP	708.31	708.31	kWh/yr
Heat Pump WH	Individual Storage HPWHs	1875.20	1339.43	kWh/yr

Note: HVAC electricity consumption includes heating and cooling

Update 2.0 **Gas Consumption (MCF/yr)**

		Heating+Cooling Gas Consumption per Year (Standard Efficiency)	Heating+Cooling Gas Consumption per Year (High Efficiency)
Heat Pump HVAC	Gas DFHP	68.64	57.80
	Gas Abs. HP	75.15	75.15

Update 2.0 **Propane Consumption (gallons/yr)**

		Heating Propane Consumption per Year (Standard Efficiency)	Heating Propane Consumption per Year (High Efficiency)
Heat Pump HVAC	Propane DFHP	723.43	609.20

	Scenario
Electricity Generation Emissions Factor	MISO PROMOD Analysis

Electricity Generation Emissions Factors

Emissions Reduction Scenario	Emission	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO PROMOD Analysis	CO2	metric ton/MWh	0.70733	0.73544	0.71548	0.67310	0.63977	0.62644	0.56563	0.57017	0.54468	0.53536	0.51886	0.52830	0.50388	0.50807	0.51331	0.49752	0.49018
MISO PROMOD Analysis	NOx	metric ton/MWh	0.00051	0.00047	0.00050	0.00035	0.00037	0.00037	0.00030	0.00033	0.00031	0.00030	0.00026	0.00027	0.00025	0.00024	0.00026	0.00024	0.00023
MISO PROMOD Analysis	SO2	metric ton/MWh	0.00070	0.00090	0.00068	0.00049	0.00042	0.00039	0.00034	0.00038	0.00035	0.00035	0.00027	0.00031	0.00027	0.00024	0.00030	0.00031	0.00024
DTE Environmental Target	CO2	metric ton/MWh	0.64650	0.68241	0.59197	0.50154	0.46466	0.42778	0.39091	0.35403	0.31715	0.28027	0.24339	0.23381	0.22422	0.21463	0.20504	0.19545	0.18586
DTE Environmental Target	NOx	metric ton/MWh	0.00035	0.00039	0.00023	0.00017	0.00012	0.00007	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
DTE Environmental Target	SO2	metric ton/MWh	0.00068	0.00108	0.00020	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
DTE Marginal Emissions Forecast	CO2	metric ton/MWh	0.73544	0.73544	0.71548	0.67310	0.63977	0.62644	0.56563	0.57017	0.54468	0.53536	0.51886	0.49721	0.47555	0.45389	0.43223	0.41058	0.38892
DTE Marginal Emissions Forecast	NOx	metric ton/MWh	0.00047	0.00047	0.00050	0.00035	0.00037	0.00037	0.00030	0.00033	0.00031	0.00030	0.00026	0.00024	0.00021	0.00019	0.00017	0.00015	0.00013
DTE Marginal Emissions Forecast	SO2	metric ton/MWh	0.00090	0.00090	0.00068	0.00049	0.00042	0.00039	0.00034	0.00038	0.00035	0.00035	0.00027	0.00021	0.00014	0.00008	0.00002	0.00000	0.00000

Fuel Emissions Factors

Fuel	CO2 Emissions	Units	N2O Emissions	Units	Source
Natural Gas	54.44	kg/1000 cubic ft	0.00010	kg/1000 cubic ft	https://www.epa.gov/sites/default/files/2020-04/documents/ghg-emission-factors-hub.pdf
Fuel Oil	10.21	kg/gallon	0.00008	kg/gallon	https://www.epa.gov/sites/default/files/2020-04/documents/ghg-emission-factors-hub.pdf
Propane	5.72	kg/gallon	0.00005	kg/gallon	https://www.epa.gov/sites/default/files/2020-04/documents/ghg-emission-factors-hub.pdf

Global Warming Potential

	GWP	Units	Source
N2O	298	CO2-eq 100-Year GW	https://www.epa.gov/sites/default/files/2020-04/documents/ghg-emission-factors-hub.pdf

Outputs

Standard Efficiency	Emissions (Metric Ton CO2-eq/yr)	Efficiency	HelperCol	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Heat Pump HVAC	Central ccASHP	Standard	Central ccASHPStand	5.8562	5.9750	5.8980	5.3023	5.1092	5.0239	4.4758	4.5557	4.3413	4.2702	4.0618	4.1437	3.9520	3.9615	4.0306	3.8735	3.8141
	Ductless ccASHP	Standard	Ductless ccASHPStan	5.5524	5.6651	5.5921	5.0273	4.8442	4.7634	4.2437	4.3194	4.1162	4.0487	3.8512	3.9288	3.7471	3.7560	3.8216	3.6726	3.6163
	GSHP	Standard	GSHPStandard	5.5497	5.6623	5.5892	5.0248	4.8418	4.7610	4.2416	4.3172	4.1141	4.0467	3.8492	3.9268	3.7452	3.7541	3.8196	3.6708	3.6145
	A2W HP	Standard	A2W HPStandard	6.1827	6.3082	6.2268	5.5980	5.3941	5.3041	4.7254	4.8097	4.5834	4.5083	4.2883	4.3748	4.1724	4.1824	4.2554	4.0895	4.0268
	Propane DFHP	Standard	Propane DFHPStanda	5.4561	5.4827	5.4655	5.3325	5.2894	5.2703	5.1480	5.1658	5.1180	5.1021	5.0556	5.0738	5.0311	5.0332	5.0486	5.0135	5.0003

	Gas DFHP	Standard	Gas DFHPStandard	5.0460	5.0725	5.0553	4.9223	4.8792	4.8602	4.7378	4.7556	4.7078	4.6919	4.6454	4.6637	4.6209	4.6230	4.6384	4.6033	4.5901
	Gas Abs. HP	Standard	Gas Abs. HPStandard	4.7016	4.7140	4.7060	4.6441	4.6241	4.6152	4.5583	4.5666	4.5443	4.5369	4.5153	4.5238	4.5039	4.5049	4.5120	4.4957	4.4896
Heat Pump WH	Individual Storage HPWHs	Standard	Individual Storage HP\	1.6101	1.6428	1.6216	1.4578	1.4047	1.3813	1.2306	1.2526	1.1936	1.1741	1.1168	1.1393	1.0866	1.0892	1.1082	1.0650	1.0487

High Efficiency	**Emissions (Metric Ton CO2-eq/yr)**	**Efficiency**	**HelperCol**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Heat Pump HVAC	Central ccASHP	High	Central ccASHPHigh	5.7807	5.8980	5.8220	5.2340	5.0434	4.9592	4.4182	4.4970	4.2854	4.2152	4.0095	4.0903	3.9011	3.9104	3.9787	3.8236	3.7650
	Ductless ccASHP	High	Ductless ccASHPHigh	5.5534	5.6661	5.5930	5.0282	4.8450	4.7642	4.2244	4.3201	4.1169	4.0494	3.8518	3.9295	3.7477	3.7566	3.8222	3.6733	3.6169
	GSHP	High	GSHPHigh	4.9362	5.0363	4.9714	4.4693	4.3065	4.2347	3.7727	3.8400	3.6593	3.5994	3.4237	3.4927	3.3312	3.3391	3.3974	3.2650	3.2149
	A2W HP	High	A2W HPHigh	5.4742	5.5853	5.5132	4.9565	4.7759	4.6962	4.1839	4.2585	4.0582	3.9917	3.7969	3.8734	3.6942	3.7031	3.7677	3.6209	3.5653
	Propane DFHP	High	Propane DFHPHigh	4.7256	4.7506	4.7344	4.6091	4.5685	4.5505	4.4352	4.4520	4.4069	4.3920	4.3482	4.3654	4.3251	4.3270	4.3416	4.3085	4.2960
	Gas DFHP	High	Gas DFHPHigh	4.3802	4.4052	4.3890	4.2637	4.2231	4.2051	4.0898	4.1066	4.0615	4.0466	4.0027	4.0200	3.9796	3.9816	3.9962	3.9631	3.9506
	Gas Abs. HP	High	Gas Abs. HPHigh	4.7016	4.7140	4.7060	4.6441	4.6241	4.6152	4.5583	4.5666	4.5443	4.5369	4.5153	4.5238	4.5039	4.5049	4.5120	4.4957	4.4896
Heat Pump WH	Individual Storage HPWHs	High	Individual Storage HP\	1.1501	1.1734	1.1583	1.0413	1.0034	0.9866	0.8790	0.8947	0.8526	0.8386	0.7977	0.8138	0.7761	0.7780	0.7916	0.7607	0.7490

Analysis

Energy Related Emissions Calculations

		Fuel	**Fuel Consumption per Year (Standard Efficiency)**	**Fuel Consumption per Year (High Efficiency)**	**Units**
Heat Pump HVAC	Central ccASHP	Electricity	6820.32	6732.44	kWh/yr
	Ductless ccASHP	Electricity	6466.57	6467.67	kWh/yr
	GSHP	Electricity	6463.32	5748.83	kWh/yr
	A2W HP	Electricity	7200.63	6375.44	kWh/yr
	Propane DFHP	Electricity	1522.57	1434.69	kWh/yr
	Gas DFHP	Electricity	1522.57	1434.69	kWh/yr
	Gas Abs. HP	Electricity	708.31	708.31	kWh/yr
Heat Pump WH	Individual Storage HPWHs	Electricity	1875.20	1339.43	kWh/yr
			Propane Consumption per Year (Standard Efficiency)	**Propane Consumption per Year (High Efficiency)**	
Heat Pump HVAC	Propane DFHP	Propane	723.430	609.204	gallons/yr
			Gas Consumption per Year (Standard Efficiency)	**Gas Consumption per Year (High Efficiency)**	
Heat Pump HVAC	Gas DFHP	Gas	68.637	57.799	MCF/yr
	Gas Abs. HP	Gas	75.151	75.151	MCF/yr

Electricity Generation Emissions Factors

Emissions Reduction Scenario	Emission	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO PROMOD Analysis	CO2	metric ton/MWh	0.70733	0.73544	0.71548	0.67310	0.63977	0.62644	0.56563	0.57017	0.54468	0.53536	0.51886	0.52830	0.50388	0.50807	0.51331	0.49752	0.49018
MISO PROMOD Analysis	NOx	metric ton/MWh	0.00051	0.00047	0.00050	0.00035	0.00037	0.00037	0.00030	0.00033	0.00031	0.00030	0.00026	0.00027	0.00025	0.00024	0.00026	0.00024	0.00023
MISO PROMOD Analysis	SO2	metric ton/MWh	0.00070	0.00090	0.00068	0.00049	0.00042	0.00039	0.00034	0.00038	0.00035	0.00035	0.00027	0.00031	0.00027	0.00024	0.00030	0.00031	0.00024

CO2 Emissions			**Fuel**	**Units**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Standard Efficiency	**Heat Pump HVAC**	Central ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	4.8798	4.5908	4.3635	4.2725	3.8578	3.8887	3.7149	3.6513	3.5388	3.6032	3.4366	3.4652	3.5009	3.3932
		Ductless ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	4.6267	4.3526	4.1371	4.0509	3.6577	3.6870	3.5222	3.4619	3.3553	3.4163	3.2584	3.2854	3.3194	3.2172
		GSHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	4.6244	4.3505	4.1351	4.0489	3.6559	3.6852	3.5204	3.4602	3.3536	3.4146	3.2568	3.2838	3.3177	3.2156
		A2W HP	Electricity	Metric Ton/yr	[illegible]	[illegible]	5.1519	4.8467	4.6068	4.5108	4.0729	4.1056	3.9220	3.8549	3.7362	3.8041	3.6283	3.6584	3.6962	3.5825
		Propane DFHP	Electricity/propane	Metric Ton/yr	[illegible]	[illegible]	5.2274	5.1629	5.1121	5.0918	4.9992	5.0061	4.9673	4.9531	4.9280	4.9424	4.9052	4.9116	4.9196	4.8955
		Gas DFHP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	4.8259	4.7614	4.7107	4.6904	4.5978	4.6047	4.5659	4.5517	4.5266	4.5409	4.5038	4.5101	4.5181	4.4941
		Gas Abs. HP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	4.5980	4.5680	4.5444	4.5349	4.4919	4.4951	4.4770	4.4704	4.4587	4.4654	4.4481	4.4511	4.4548	4.4436
	Heat Pump WH	Individual Storage HPWHs	Electricity	Metric Ton/yr	[illegible]	[illegible]	1.3417	1.2622	1.1997	1.1747	1.0607	1.0692	1.0214	1.0039	0.9730	0.9907	0.9449	0.9527	0.9626	0.9330

CO2 Emissions			**Fuel**	**Units**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
High Efficiency	**Heat Pump HVAC**	Central ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	4.8169	4.5316	4.3072	4.2175	3.8081	3.8386	3.6670	3.6043	3.4932	3.5567	3.3924	3.4205	3.4558	3.3495
		Ductless ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	4.6275	4.3534	4.1378	4.0516	3.6583	3.6877	3.5228	3.4625	3.3558	3.4169	3.2590	3.2860	3.3199	3.2178
		GSHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	4.1132	3.8695	3.6779	3.6013	3.2517	3.2778	3.1313	3.0777	2.9829	3.0371	2.8967	2.9208	2.9509	2.8602
		A2W HP	Electricity	Metric Ton/yr	[illegible]	[illegible]	4.5615	4.2913	4.0788	3.9938	3.6061	3.6351	3.4726	3.4131	3.3080	3.3681	3.2125	3.2391	3.2726	3.1719
		Propane DFHP	Electricity/propane	Metric Ton/yr	[illegible]	[illegible]	4.5111	4.4503	4.4025	4.3834	4.2962	4.3027	4.2661	4.2527	4.2291	4.2426	4.2076	4.2136	4.2211	4.1984
		Gas DFHP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	4.1731	4.1123	4.0645	4.0453	3.9581	3.9646	3.9280	3.9147	3.8910	3.9045	3.8695	3.8755	3.8830	3.8604
		Gas Abs. HP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	4.5980	4.5680	4.5444	4.5349	4.4919	4.4951	4.4770	4.4704	4.4587	4.4654	4.4481	4.4511	4.4548	4.4436
	Heat Pump WH	Individual Storage HPWHs	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.9583	0.9016	0.8569	0.8391	0.7576	0.7637	0.7296	0.7171	0.6950	0.7076	0.6749	0.6805	0.6875	0.6664

N2O Emissions			**Fuel**	**Units**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Standard Efficiency	**Heat Pump HVAC**	Central ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0034	0.0024	0.0025	0.0025	0.0021	0.0022	0.0021	0.0021	0.0018	0.0018	0.0017	0.0017	0.0018	0.0016
		Ductless ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0032	0.0023	0.0024	0.0024	0.0020	0.0021	0.0020	0.0020	0.0017	0.0017	0.0016	0.0016	0.0017	0.0015
		GSHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0032	0.0023	0.0024	0.0024	0.0020	0.0021	0.0020	0.0020	0.0017	0.0017	0.0016	0.0016	0.0017	0.0015
		A2W HP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0036	0.0025	0.0026	0.0027	0.0022	0.0024	0.0022	0.0022	0.0019	0.0019	0.0018	0.0018	0.0019	0.0017
		Propane DFHP	Electricity/propane	Metric Ton/yr	[illegible]	[illegible]	0.0008	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
		Gas DFHP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	0.0008	0.0005	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
		Gas Abs. HP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	0.0004	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
	Heat Pump WH	Individual Storage HPWHs	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0009	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0005	0.0004

N2O Emissions			**Fuel**	**Units**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
High Efficiency	**Heat Pump HVAC**	Central ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0034	0.0024	0.0025	0.0025	0.0020	0.0022	0.0021	0.0021	0.0017	0.0018	0.0017	0.0016	0.0018	0.0016
		Ductless ccASHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0032	0.0023	0.0024	0.0024	0.0020	0.0021	0.0020	0.0020	0.0017	0.0017	0.0016	0.0016	0.0017	0.0015
		GSHP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0029	0.0020	0.0021	0.0021	0.0017	0.0019	0.0018	0.0018	0.0015	0.0015	0.0015	0.0014	0.0015	0.0014
		A2W HP	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0032	0.0022	0.0023	0.0024	0.0019	0.0021	0.0020	0.0019	0.0016	0.0017	0.0016	0.0016	0.0017	0.0015
		Propane DFHP	Electricity/propane	Metric Ton/yr	[illegible]	[illegible]	0.0007	0.0005	0.0006	0.0006	0.0005	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
		Gas DFHP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	0.0007	0.0005	0.0005	0.0005	0.0004	0.0005	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0003
		Gas Abs. HP	Electricity/gas	Metric Ton/yr	[illegible]	[illegible]	0.0004	0.0003	0.0003	0.0003	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
	Heat Pump WH	Individual Storage HPWHs	Electricity	Metric Ton/yr	[illegible]	[illegible]	0.0007	0.0005	0.0005	0.0005	0.0004	0.0004	0.0004	0.0004	0.0003	0.0004	0.0003	0.0003	0.0003	0.0003

Total Emissions			Fuel	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Standard Efficiency	**Heat Pump HVAC**	Central ccASHP	Electricity	Metric Ton CO2-eq /yr	5.8562	5.9750	5.8980	5.3023	5.1092	5.0239	4.4758	4.5557	4.3413	4.2702	4.0618	4.1437	3.9520	3.9615	4.0306	3.8735
		Ductless ccASHP	Electricity	Metric Ton CO2-eq /yr	5.5524	5.6651	5.5921	5.0273	4.8442	4.7634	4.2437	4.3194	4.1162	4.0487	3.8512	3.9288	3.7471	3.7560	3.8216	3.6726
		GSHP	Electricity	Metric Ton CO2-eq /yr	5.5497	5.6623	5.5892	5.0248	4.8418	4.7610	4.2416	4.3172	4.1141	4.0467	3.8492	3.9268	3.7452	3.7541	3.8196	3.6708
		A2W HP	Electricity	Metric Ton CO2-eq /yr	6.1827	6.3082	6.2268	5.5980	5.3941	5.3041	4.7254	4.8097	4.5834	4.5083	4.2883	4.3748	4.1724	4.1824	4.2554	4.0895
		Propane DFHP	Electricity/propane	Metric Ton CO2-eq /yr	5.4561	5.4827	5.4655	5.3325	5.2894	5.2703	5.1480	5.1658	5.1180	5.1021	5.0556	5.0738	5.0311	5.0332	5.0486	5.0135
		Gas DFHP	Electricity/gas	Metric Ton CO2-eq /yr	5.0460	5.0725	5.0553	4.9223	4.8792	4.8602	4.7378	4.7556	4.7078	4.6919	4.6454	4.6637	4.6209	4.6230	4.6384	4.6033
		Gas Abs. HP	Electricity/gas	Metric Ton CO2-eq /yr	4.7016	4.7140	4.7060	4.6441	4.6241	4.6152	4.5583	4.5666	4.5443	4.5369	4.5153	4.5238	4.5039	4.5049	4.5120	4.4957
	Heat Pump WH	Individual Storage HPWHs	Electricity	Metric Ton CO2-eq /yr	1.6101	1.6428	1.6216	1.4578	1.4047	1.3813	1.2306	1.2526	1.1936	1.1741	1.1168	1.1393	1.0866	1.0892	1.1082	1.0650

Total Emissions			Fuel	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
High Efficiency	**Heat Pump HVAC**	Central ccASHP	Electricity	Metric Ton CO2-eq /yr	5.7807	5.8980	5.8220	5.2340	5.0434	4.9592	4.4182	4.4970	4.2854	4.2152	4.0095	4.0903	3.9011	3.9104	3.9787	3.8236
		Ductless ccASHP	Electricity	Metric Ton CO2-eq /yr	5.5534	5.6661	5.5930	5.0282	4.8450	4.7642	4.2444	4.3201	4.1169	4.0494	3.8518	3.9295	3.7477	3.7566	3.8222	3.6733
		GSHP	Electricity	Metric Ton CO2-eq /yr	4.9362	5.0363	4.9714	4.4693	4.3065	4.2347	3.7727	3.8400	3.6593	3.5994	3.4237	3.4927	3.3312	3.3391	3.3974	3.2650
		A2W HP	Electricity	Metric Ton CO2-eq /yr	5.4742	5.5853	5.5132	4.9565	4.7759	4.6962	4.1839	4.2585	4.0582	3.9917	3.7969	3.8734	3.6942	3.7031	3.7677	3.6209
		Propane DFHP	Electricity/propane	Metric Ton CO2-eq /yr	4.7256	4.7506	4.7344	4.6091	4.5685	4.5505	4.4352	4.4520	4.4069	4.3920	4.3482	4.3654	4.3251	4.3270	4.3416	4.3085
		Gas DFHP	Electricity/gas	Metric Ton CO2-eq /yr	4.3802	4.4052	4.3890	4.2637	4.2231	4.2051	4.0898	4.1066	4.0615	4.0466	4.0027	4.0200	3.9796	3.9816	3.9962	3.9631
		Gas Abs. HP	Electricity/gas	Metric Ton CO2-eq /yr	4.7016	4.7140	4.7060	4.6441	4.6241	4.6152	4.5583	4.5666	4.5443	4.5369	4.5153	4.5238	4.5039	4.5049	4.5120	4.4957
	Heat Pump WH	Individual Storage HPWHs	Electricity	Metric Ton CO2-eq /yr	1.1501	1.1734	1.1583	1.0413	1.0034	0.9866	0.8790	0.8947	0.8526	0.8386	0.7977	0.8138	0.7761	0.7780	0.7916	0.7607

Emissions Reduction Scenario	Emission	Units	2020	2021	2022	2023	2024	2025	2026
MISO PROMOD Analysis	CO2	metric ton/MWh	0.70733	0.73544	0.71548	0.67310	0.63977	0.62644	0.56563
MISO PROMOD Analysis	NOx	metric ton/MWh	0.00051	0.00047	0.00050	0.00035	0.00037	0.00037	0.00030
MISO PROMOD Analysis	SO2	metric ton/MWh	0.00070	0.00090	0.00068	0.00049	0.00042	0.00039	0.00034
DTE Environmental Target	CO2	metric ton/MWh	0.64650	0.68241	0.59197	0.50154	0.46466	0.42778	0.39091
DTE Environmental Target	NOx	metric ton/MWh	0.00035	0.00039	0.00023	0.00017	0.00012	0.00007	0.00001
DTE Environmental Target	SO2	metric ton/MWh	0.00068	0.00108	0.00020	0.00000	0.00000	0.00000	0.00000
DTE Marginal Emissions Forecast	CO2	metric ton/MWh	0.73544	0.73544	0.71548	0.67310	0.63977	0.62644	0.56563
DTE Marginal Emissions Forecast	NOx	metric ton/MWh	0.00047	0.00047	0.00050	0.00035	0.00037	0.00037	0.00030
DTE Marginal Emissions Forecast	SO2	metric ton/MWh	0.00090	0.00090	0.00068	0.00049	0.00042	0.00039	0.00034

Emissions Reduction Scenario	Emission	2027	2028	2029	2030	2031	2032	2033	2034
MISO PROMOD Analysis	CO2	0.57017	0.54468	0.53536	0.51886	0.52830	0.50388	0.50807	0.51331
MISO PROMOD Analysis	NOx	0.00033	0.00031	0.00030	0.00026	0.00027	0.00025	0.00024	0.00026
MISO PROMOD Analysis	SO2	0.00038	0.00035	0.00035	0.00027	0.00031	0.00027	0.00024	0.00030
DTE Environmental Target	CO2	0.35403	0.31715	0.28027	0.24339	0.23381	0.22422	0.21463	0.20504
DTE Environmental Target	NOx	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
DTE Environmental Target	SO2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
DTE Marginal Emissions Forecast	CO2	0.57017	0.54468	0.53536	0.51886	0.49721	0.47555	0.45389	0.43223
DTE Marginal Emissions Forecast	NOx	0.00033	0.00031	0.00030	0.00026	0.00024	0.00021	0.00019	0.00017
DTE Marginal Emissions Forecast	SO2	0.00038	0.00035	0.00035	0.00027	0.00021	0.00014	0.00008	0.00002

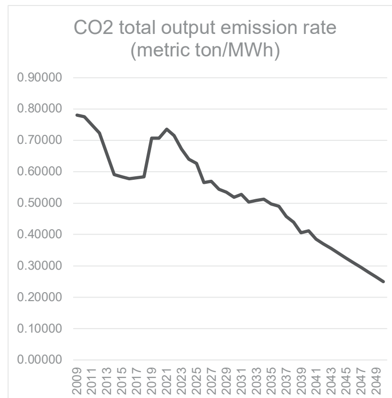
Emissions Reduction Scenario	Emission	2035	2036	2037	2038	2039	2040	2041
MISO PROMOD Analysis	CO2	0.49752	0.49018	0.45759	0.43944	0.40594	0.41201	0.38570
MISO PROMOD Analysis	NOx	0.00024	0.00023	0.00019	0.00016	0.00014	0.00016	0.00012
MISO PROMOD Analysis	SO2	0.00031	0.00024	0.00017	0.00014	0.00013	0.00020	0.00007
DTE Environmental Target	CO2	0.19545	0.18586	0.17628	0.16669	0.15710	0.14751	0.13276
DTE Environmental Target	NOx	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
DTE Environmental Target	SO2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
DTE Marginal Emissions Forecast	CO2	0.41058	0.38892	0.36726	0.34560	0.32395	0.30229	0.28063
DTE Marginal Emissions Forecast	NOx	0.00015	0.00013	0.00011	0.00009	0.00006	0.00004	0.00002
DTE Marginal Emissions Forecast	SO2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

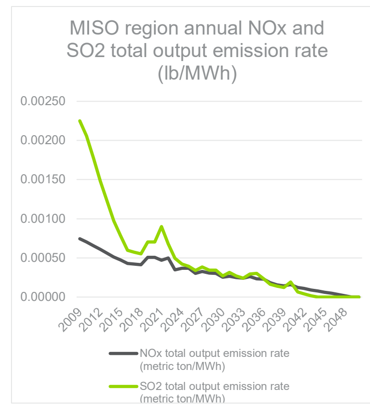
Notes:
1) MISO PROMOD analysis baseline year (2020) emissions show slight differences from the DTE provided values because they encompass a larger geographical area beyond DTE service areas.
2) The difference between the MISO PROMOD and DTE baseline year emission values are small (<10%) and is insignificant with respect to the large differences in emissions projections.

MISO PROMOD Analysis

Year	MISO annual NOx total output emission rate (lb/MWh)	MISO region annual SO2 total output emission rate (lb/MWh)	MISO region annual CO2 total output emission rate (lb/MWh)	NOx total output emission rate (metric ton/MWh)	SO2 total output emission rate (metric ton/MWh)	CO2 total output emission rate (metric ton/MWh)
2009	1.646444145	4.962227264	1721.215883	0.00075	0.00225	0.78073
2010	1.548785082	4.535254599	1710.131693	0.00070	0.00206	0.77570
2011	1.447415529	3.900329381	1653.065886	0.00066	0.00177	0.74982
2012	1.346045977	3.265404162	1596.00008	0.00061	0.00148	0.72393
2013	1.240623696	2.706247823	1449.764102	0.00056	0.00123	0.65760
2014	1.135201416	2.147091484	1303.528125	0.00051	0.00097	0.59127
2015	1.043677239	1.73365024	1288.677034	0.00047	0.00079	0.58453
2016	0.952153063	1.320208995	1273.825943	0.00043	0.00060	0.57780
2017	0.932460445	1.271879806	1281.091947	0.00042	0.00058	0.58109
2018	0.912767827	1.223550618	1288.357952	0.00041	0.00055	0.58439
2019	1.119351419	1.549947173	1559.404174	0.00051	0.00070	0.70733
2020	1.119351419	1.549947173	1559.404174	0.00051	0.00070	0.70733
2021	1.040316562	1.987233388	1621.366352	0.00047	0.00090	0.73544
2022	1.104384848	1.502724417	1577.367459	0.00050	0.00068	0.71548
2023	0.771871081	1.091048633	1483.930316	0.00035	0.00049	0.67310
2024	0.80893129	0.927092117	1410.455669	0.00037	0.00042	0.63977
2025	0.815057923	0.86953371	1381.064619	0.00037	0.00039	0.62644
2026	0.67040891	0.753468924	1247.00072	0.00030	0.00034	0.56563
2027	0.723436088	0.848055412	1257.007204	0.00033	0.00038	0.57017
2028	0.679497719	0.761798143	1200.815094	0.00031	0.00035	0.54468
2029	0.671325249	0.764532884	1180.263558	0.00030	0.00035	0.53536
2030	0.567312789	0.597306395	1143.899782	0.00026	0.00027	0.51886
2031	0.586352626	0.692937394	1164.69733	0.00027	0.00031	0.52830
2032	0.559039561	0.594457657	1110.872992	0.00025	0.00027	0.50388
2033	0.5383482	0.536906219	1120.091032	0.00024	0.00024	0.50807
2034	0.574543122	0.656003354	1131.654413	0.00026	0.00030	0.51331
2035	0.520974172	0.674827229	1096.843305	0.00024	0.00031	0.49752
2036	0.510862727	0.520903825	1080.651094	0.00023	0.00024	0.49018
2037	0.410227972	0.365672348	1008.810702	0.00019	0.00017	0.45759
2038	0.343516771	0.308571879	968.7887061	0.00016	0.00014	0.43944
2039	0.317248291	0.277542181	894.9476519	0.00014	0.00013	0.40594
2040	0.357696254	0.4317378	908.333924	0.00016	0.00020	0.41201
2041	0.275543078	0.151452602	850.3244823	0.00012	0.00007	0.38570
2042	0.241921694	0.093674974	817.0750905	0.00011	0.00004	0.37062
2043	0.20830031	0.035897346	783.8256988	0.00009	0.00002	0.35554
2044	0.174678926	0	750.576307	0.00008	0.00000	0.34046
2045	0.141057542	0	717.3269152	0.00006	0.00000	0.32537
2046	0.107436159	0	684.0775234	0.00005	0.00000	0.31029
2047	0.073814775	0	650.8281316	0.00003	0.00000	0.29521
2048	0.040193391	0	617.5787398	0.00002	0.00000	0.28013
2049	0.006572007	0	584.329348	0.00000	0.00000	0.26505
2050	0	0	551.0799563	0.00000	0.00000	0.24997

Sources:
ISO Level (MISO) from eGRID (2009-2018); ISO Level (MISO) from Guidehouse PROMOD Analysis (2019-2040)
Metric Tons to Pounds: 2204.62





Note: Blue text indicate linearly extrapolated values

DTE Environmental Target

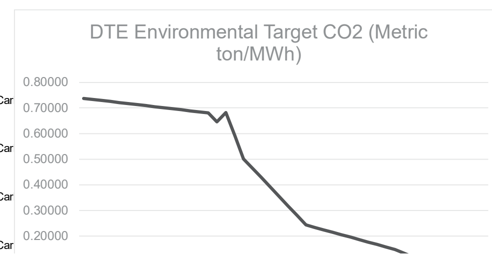
Emission	Units	2005	2006	2007	2008	2009	2010	2011	2012
CO2	metric ton/MWh	0.73756	0.73349	0.72943	0.72537	0.72130	0.71724	0.71317	0.70911
NOx	metric ton/MWh	0.00112	0.00107	0.00102	0.00096	0.00091	0.00086	0.00080	0.00075
SO2	metric ton/MWh	0.00373	0.00352	0.00331	0.00310	0.00289	0.00268	0.00247	0.00226

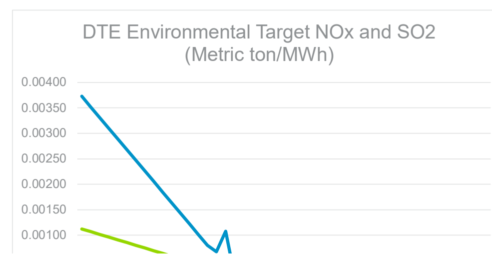
Emission	2013	2014	2015	2016	2017	2018	2019	2020
CO2	0.70504	0.70098	0.69691	0.69285	0.68878	0.68472	0.6806544	0.6465004
NOx	0.00070	0.00064	0.00059	0.00054	0.00048	0.00043	0.0003787	0.0003454
SO2	0.00206	0.00185	0.00164	0.00143	0.00122	0.00101	0.0008021	0.0006765

Emission	2021	2022	2023	2024	2025	2026	2027
CO2	0.68241	0.59197	0.5015403	0.46466	0.42778	0.39091	0.35403
NOx	0.00039	0.0002251	0.0001725	0.0001199	6.731E-05	1.471E-05	0
SO2	0.00108	0.0001997	0	0	0	0	0

Source: https://empoweringmichigan.com/dte-impact/performance/
Source: https://geg2a4cqgdz35lnem46az2tb-wpengine.netdna-ssl.com/wp-content/uploads/2020-2021-Key-Performance-Data.xlsx

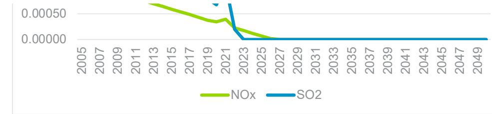
Goal Applicability	Baseline Year	Target Year	Reduction Goal De	Reduction	Source (URL)
DTE Electric	2005	2023	32% reduction in the carbon emissions of	32%	DTE Energy - Net Zero Car
DTE Electric	2005	2030	50% reduction in the carbon emissions of	67%	DTE Energy - Net Zero Car
DTE Electric	2005	2040	80% reduction in the carbon emissions of	80%	DTE Energy - Net Zero Car
DTE Electric	2005	2050	Net zero carbon emissions of electricity delivered	100%	DTE Energy - Net Zero Car





Note: Orange text indicate projected values
Note: Green text indicate linearly interpolated values
Note: Blue text indicate linearly extrapolated values

Updated to reflect more aggressive goals in DTE IRP : https://dtecleanenergy.com/downloads/IRP_Executive_Summary.pdf



DTE Marginal Emissions Forecast

Emission	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CO2	metric ton/MWh		0.73544	0.71548	0.67310	0.63977	0.62644	0.56563	0.57017	0.54468	0.53536	0.51886	0.49721	0.47555	0.45389	0.43223	0.41058	0.38892	0.36726	0.34560	0.32395	0.30229	0.28063	0.25897
NOx	metric ton/MWh		0.00047	0.00050	0.00035	0.00037	0.00037	0.00030	0.00033	0.00031	0.00030	0.00026	0.00024	0.00021	0.00019	0.00017	0.00015	0.00013	0.00011	0.00009	0.00006	0.00004	0.00002	0.00000
SO2	metric ton/MWh		0.00090	0.00068	0.00049	0.00042	0.00039	0.00034	0.00038	0.00035	0.00035	0.00027	0.00021	0.00014	0.00008	0.00002	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

Source : 2021 Energy Waste Reduction Reconciliation Exhibit Draft dated June 3, 2022

Note: Green text indicate linearly extrapolated values

Emissions Reduction Scenari	27	
MISO PROMOD Analysis	0.00000	00000
MISO PROMOD Analysis	0.00000	00000
MISO PROMOD Analysis	0.00000	00000
DTE Environmental Target	0.00000	00000
DTE Environmental Target	0.00000	00000
DTE Environmental Target	0.00000	00000
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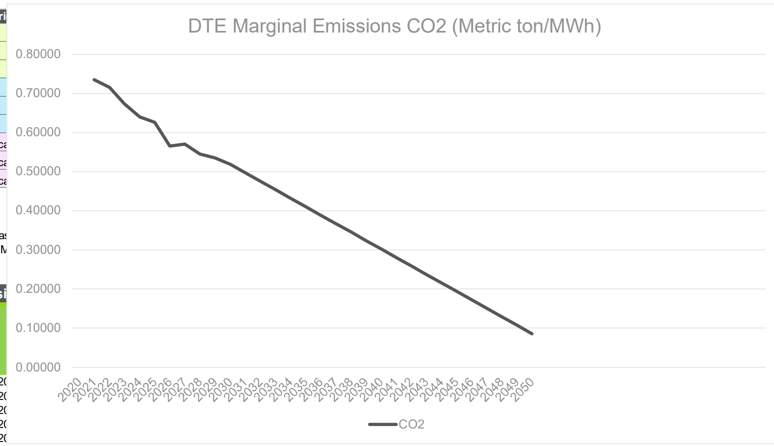

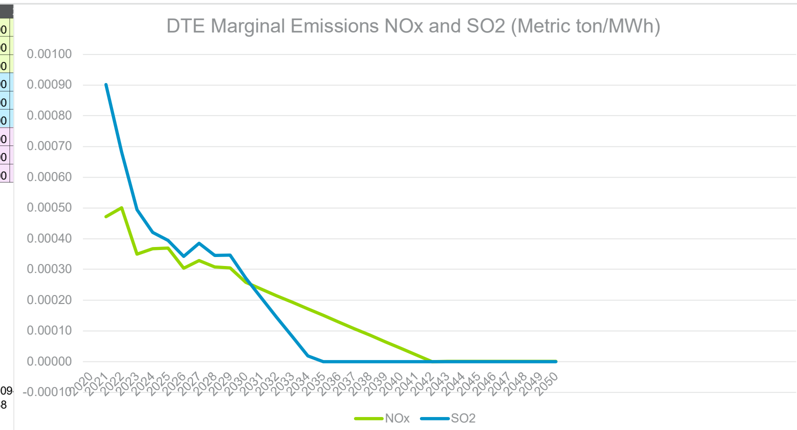

Notes:
1) MISO PROMOD analysis bas ... as.
2) The difference between the M

MISO PROMOD Analysi

Year

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2056	0.059362003	-0.931671666	837.8847265	0.00003	-0.00042	0.38006

Executive Summary

Multiple states in the U.S. have adopted ambitious climate targets requiring the achievement of net-zero greenhouse gas (GHG) emissions. To meet these climate targets and utility net-zero goals, utilities, regulators, and other stakeholders have begun planning for a future that is less reliant on fossil gas and more dependent on clean energy resources. Progress towards this future can be significantly advanced through integrated energy planning and adoption of non-pipeline alternative solutions.

Integrated energy planning (IEP) is the practice of incorporating critical interactions between gas, electric, and customer energy systems into utility and energy planning processes in the context of long-term climate goals. By recognizing the interdependent nature of today's energy systems, integrated energy planning can aid in assessing the infrastructure and customer impacts of potential transition strategies. This serves to advance net-zero goals most cost-effectively and equitably, while ensuring the safety and reliability of the systems customers rely on.

Non-pipeline alternatives (NPAs) are projects or initiatives intended to simultaneously reduce GHG emissions and defer, reduce, or avoid the need to construct or upgrade components of the natural gas system through customers' installation of all-electric equipment or connection to other lower-carbon infrastructure, including thermal energy networks. NPAs are an emerging area of opportunity for gas system decarbonization in the U.S., with the potential to achieve ratepayer savings across three categories of gas network investment: replacement of existing infrastructure, capacity expansion of existing system, and system extension to new customers.

National Grid U.S. is working to advance its own planning processes in accordance with the goals of the jurisdictions in which it operates, Massachusetts and New York. In order to better understand the landscape of non-pipeline alternatives and integrated energy planning in the gas industry today, National Grid and RMI worked together to identify case studies where NPAs and integrated energy planning have been implemented or developed. This research included interviewing utilities, non-governmental organizations (NGOs), consultants, and others working to deploy NPAs and integrated energy planning in diverse jurisdictions across the U.S. and Europe.

This whitepaper is divided into two parts:

First, we present nine case studies describing the current state of NPA initiatives and integrated energy planning in the U.S. and Europe. These case studies include projects that have moved toward implementation in both the U.S. and Europe, including the decommissioning of specific gas infrastructure.

For example:

- Pacific Gas & Electric (PG&E) in California has completed 88 NPA projects, converting a total of 105 customers from gas. Other U.S. utilities advancing projects include National Grid, Con Edison, Rochester Gas and Electric, and Xcel.
- In Europe, municipal clean heat planning is prevalent or required in multiple countries including the Netherlands and Switzerland. While Zurich is the only example of a city that has completed neighborhood-scale decommissioning to date, other cities in Switzerland and elsewhere are working to follow suit.
- Combination utilities in the U.S. such as National Grid and Xcel are working to integrate internal gas and electric planning teams and develop new tools and processes for integrated energy planning. An early example of cross-utility planning can also be found in Québec, where the gas and electric utilities received regulatory approval for a joint decarbonization strategy that accounts for the benefits each system provides the other.

Then, based on our research and learnings, National Grid and RMI offer the following eight insights for further exploration by U.S. utilities, regulators, policymakers, and other stakeholders to advance the deployment of NPAs and integrated energy planning:

NPA projects underway today reflect diverse energy policy goals and energy system characteristics across different jurisdictions. Clean heat planning is generally motivated by environmental and economic concerns, while some jurisdictions are also motivated by geopolitical and equity concerns. This diversity will necessarily shape the solutions that meet each jurisdiction's goals and needs.

NPA projects can identify value in cost savings on the gas system, emissions reduction, or other societal benefits. Utilities looking to develop cost tests for NPA projects should start by identifying the key costs and benefits, which may vary by jurisdiction and emissions valuation structure.

Prioritization of NPA projects should weigh a broad set of criteria, including gas asset risk and hydraulic feasibility, electric capacity, benefit-cost criteria, customer propensity for new technology adoption, and community factors. Some near-term areas of opportunity for NPAs are high-cost gas asset replacements where there is electric headroom and fewer than five customers on a segment.

NPA projects can be funded from a series of different sources while protecting ratepayers' long-term affordability. To date, NPA projects have been funded by gas ratepayers. However, to help mitigate upward rate pressure for gas customers as gas demand declines, consideration should be given to alternative funding sources, including federal, state or local taxpayer funding, as well as electric ratepayer funding.

Integrated gas and electric network planning offers the opportunity to achieve net-zero goals as cost-effectively and equitably as possible. Regulatory support will be required to enable cross-utility data sharing and decision-making, and to invest in new tools and capabilities.

Utility and municipality partnership may be a key element of NPA projects and localized integrated energy planning. Partnering at the municipal level is a valuable way to ensure alignment, build community support, and incorporate local priorities in project planning.

In presenting this work, we hope the case studies and insights detailed herein will serve as a catalyst for advancing the implementation of NPAs and integrated energy planning across the U.S.

Individual customer persuasion to reach 100% participation is not a scalable NPA approach for avoided replacement projects. Under the current regulatory framework, NPAs that avoid infrastructure replacement require voluntary and coordinated conversion of 100% of customers on the segment from gas to all-electric equipment. To date, no U.S. utility has successfully completed this type of NPA under the existing regulatory framework for projects serving greater than five customers.

Policy change will be needed to evolve the utility business model and obligation to serve, while retaining the opportunity for cost recovery in a transition away from the use of gas. State regulators will have a critical role in overseeing substantial changes to the provision of utility service that enable NPA projects to scale.

In presenting this work, we hope the case studies and insights detailed herein will serve as a catalyst for advancing the implementation of NPAs and integrated energy planning across the U.S.

MPSC Case No: U-21973
Requester: MECCUB
Question No.: MECCUBDG-3.8a
Respondent: J. L. Huffman
Page: 1 of 1

Question: Refer to the Direct Testimony of George H. Chapel, p. 20 lines 4-6:

a. Describe in detail the marketing initiatives.

Answer: The Company actively communicates to potential customers that are close to its main the benefits of switching to natural gas from propane. The Company leverages various channels including direct mail, paid social, digital, etc. These campaigns result in new customer attachments.

Attachment: None

MPSC Case No: U-21973	
Requester: FLO	
Question No.: FLODG-4.IV2bii	
Respondent: J. L. Huffman	
Page: 1 of 1	

Question: IV. Renewable Natural Gas

2. Refer to the Company's Gas Delivery Plan (GDP, Exhibit A-12 B5.6) mentioned in Direct Testimony of Henry J. Decker at Page 5.

b. Refer to "Historic and Projected New Attachments by Category." Exhibit A-12 B5.6, fig. 25 at 34 (showing more community expansions beginning in 2026 than the historic trend). According to the Company, the upward trend in construction activity is supported by "the Company's strategic focus on proactive growth channels . . . [and] a significant rise in inbound inquiries" from customers interested in converting from propane to natural gas. Exhibit A-12 B5.6 at 34. Please share the following data:

ii. How much the Company plans to spend each year going forward on "proactive growth channel" efforts.

Answer: The amount we are projecting to spend is $324,381 annually, plus inflation, on marketing in proactive growth channels.

Attachment: None

Co-Respondent(s): H. J. Decker

MPSC Case No: U-21973
Requester: Ann Arbor
Question No.: AADG-2.7a
Respondent: J. L. Huffman
Page: 1 of 1

Question: Please provide responses to the following requests regarding the Customer Attachment Program (CAP) Model and Methodology.

a. Please provide the complete, functional CAP model, including all underlying spreadsheets, formulas, and assumptions, used to evaluate each Area Expansion Project (AEP) approved or proposed for 2024-2027.

Answer: The Company is providing complete CAP models for AEPs installed for calendar years 2024-2026. The projects for 2027 do not yet have completed CAP models.

See attachments for the following projects:

Project Name	Year Installed	Attachment Name
Adams	2024	U-21973 AADG-2.7a-01 2024 Adams CAP Model - Final
Ashton	2024	U-21973 AADG-2.7a-02 2024 Ashton CAP Model - Final
Bosset Rd	2024	U-21973 AADG-2.7a-03 2024 Bosset Rd CAP Model - Final
Bush Rd	2024	U-21973 AADG-2.7a-04 2024 Bush Rd CAP Model - Final
Click Rd	2024	U-21973 AADG-2.7a-05 2024 Click Rd CAP Model - Final
Cranberry Lake	2024	U-21973 AADG-2.7a-06 2024 Cranberry Lake CAP Model - Final
Crystal Lake	2024	U-21973 AADG-2.7a-07 2024 Crystal Lake CAP Model - Final
E 32nd	2024	U-21973 AADG-2.7a-08 2024 E 32nd CAP Model - Final
Green Lake	2024	U-21973 AADG-2.7a-09 2024 Green Lake CAP Model - Final
Hart Rd	2024	U-21973 AADG-2.7a-10 2024 Hart Rd CAP Model - Final
Hobbs Highway	2024	U-21973 AADG-2.7a-11 2024 Hobbs Highway CAP Model - Final
Holton Whitehall	2024	U-21973 AADG-2.7a-12 2024 Holton Whitehall CAP Model - Final

Iris Rd	2024	U-21973 AADG-2.7a-13 2024 Iris Rd CAP Model - Final
M-55	2024	U-21973 AADG-2.7a-14 2024 M-55 CAP Model - Final
Mead Rd	2024	U-21973 AADG-2.7a-15 2024 Mead Rd CAP Model - Final
Mesick – Buckley Additions	2024	U-21973 AADG-2.7a-16 2024 Mesick-Buckley Additions CAP Model - Final
Mesick – Buckley	2024	U-21973 AADG-2.7a-17 2024 Mesick-Buckley CAP Model - Final
Morgan Mills	2024	U-21973 AADG-2.7a-18 2024 Morgan Mills CAP Model - Final
Negaunee Miramichi Lakes	2024	U-21973 AADG-2.7a-19 2024 Negaunee Miramichi Lakes CAP Model - Final
Podunk	2024	U-21973 AADG-2.7a-20 2024 Podunk CAP Model - Final
Ridge Lane	2024	U-21973 AADG-2.7a-21 2024 Ridge Lane CAP Model - Final
S Grayling Rd	2024	U-21973 AADG-2.7a-22 2024 S Grayling Rd CAP Model - Final
Satterlee Rd	2024	U-21973 AADG-2.7a-23 2024 Satterlee Rd CAP Model - Final
Solon St	2024	U-21973 AADG-2.7a-24 2024 Solon St CAP Model - Final
Stage Ave	2024	U-21973 AADG-2.7a-25 2024 Stage Ave CAP Model - Final
Vining Rd	2024	U-21973 AADG-2.7a-26 2024 Vining Rd CAP Model - Final
W 1 Mile	2024	U-21973 AADG-2.7a-27 2024 W 1 Mile CAP Model - Final
Washington Rd	2024	U-21973 AADG-2.7a-28 2024 Washington Rd CAP Model - Final
12th Rd	2025	U-21973 AADG-2.7a-29 2025 12th Rd CAP Model - Final
56th	2025	U-21973 AADG-2.7a-30 2025 56th CAP Model - Final
Austin	2025	U-21973 AADG-2.7a-31 2025 Austin CAP Model - Final
Chain of Lakes	2025	U-21973 AADG-2.7a-32 2025 Chain of Lakes CAP Model - Final
Clarence	2025	U-21973 AADG-2.7a-33 2025 Clarence CAP Model - Final
E Bard Rd	2025	U-21973 AADG-2.7a-34 2025 E Bard Rd CAP Model - Final

Eagles Nest	2025	U-21973 AADG-2.7a-35 2025 Eagles Nest CAP Model - Final
Grant Ave	2025	U-21973 AADG-2.7a-36 2025 Grant Ave CAP Model - Final
Ironton	2025	U-21973 AADG-2.7a-37 2025 Ironton CAP Model - Final
Johnson	2025	U-21973 AADG-2.7a-38 2025 Johnson CAP Model - Final
Michigan Ave	2025	U-21973 AADG-2.7a-39 2025 Michigan Ave CAP Model - Final
Richardson	2025	U-21973 AADG-2.7a-40 2025 Richardson CAP Model - Final
River Meadow	2025	U-21973 AADG-2.7a-41 2025 River Meadow CAP Model - Final
S Mt. Hope	2025	U-21973 AADG-2.7a-42 2025 S Mt. Hope CAP Model - Final
Stacey Woods	2025	U-21973 AADG-2.7a-43 2025 Stacey Woods CAP Model - Final
US 2	2025	U-21973 AADG-2.7a-44 2025 US 2 CAP Model - Final
Vergennes	2025	U-21973 AADG-2.7a-45 2025 Vergennes CAP Model - Final
West Branch Rd	2025	U-21973 AADG-2.7a-46 2025 West Branch Rd CAP Model - Final
72nd Ave	2026	U-21973 AADG-2.7a-47 2026 72nd Ave CAP Model - Final
Alpha	2026	U-21973 AADG-2.7a-48 2026 Alpha CAP Model - Final
Autumn	2026	U-21973 AADG-2.7a-49 2026 Autumn CAP Model - Final
Belding	2026	U-21973 AADG-2.7a-50 2026 Belding CAP Model - Final
Big Star Lake	2026	U-21973 AADG-2.7a-51 2026 Big Star Lake CAP Model - Final
Blanchard	2026	U-21973 AADG-2.7a-52 2026 Blanchard CAP Model - Final
Clear Lake	2026	U-21973 AADG-2.7a-53 2026 Clear Lake CAP Model - Final
Conklin	2026	U-21973 AADG-2.7a-54 2026 Conklin CAP Model - Final
Coral – Cowden Lake	2026	U-21973 AADG-2.7a-55 2026 Coral – Cowden Lake CAP Model - Final
Croton Hardy	2026	U-21973 AADG-2.7a-56 2026 Croton Hardy CAP Model - Final
Diamond Lake	2026	U-21973 AADG-2.7a-57 2026 Diamond Lake CAP Model - Final

E Bar D Rd	2026	U-21973 AADG-2.7a-58 2026 E Bar D Rd CAP Model - Final
Esmond Blvd	2026	U-21973 AADG-2.7a-59 2026 Esmond Blvd CAP Model - Final
Guthrie Lakes	2026	U-21973 AADG-2.7a-60 2026 Guthrie Lakes CAP Model - Final
Herring Lakes	2026	U-21973 AADG-2.7a-61 2026 Herring Lakes CAP Model - Final
Honeycreek	2026	U-21973 AADG-2.7a-62 2026 Honeycreek CAP Model - Final
Johnson Rd	2026	U-21973 AADG-2.7a-63 2026 Johnson Rd CAP Model - Final
Lake Tahoe	2026	U-21973 AADG-2.7a-64 2026 Lake Tahoe CAP Model - Final
Langston	2026	U-21973 AADG-2.7a-65 2026 Langston CAP Model - Final
M-72	2026	U-21973 AADG-2.7a-66 2026 M-72 CAP Model - Final
Muskegon Blvd	2026	U-21973 AADG-2.7a-67 2026 Muskegon Blvd CAP Model - Final
Reynolds Rd	2026	U-21973 AADG-2.7a-68 2026 Reynolds Rd CAP Model - Final
Rose Lake	2026	U-21973 AADG-2.7a-69 2026 Rose Lake CAP Model - Final
Shag Lake	2026	U-21973 AADG-2.7a-70 2026 Shag Lake CAP Model - Final
Summit City	2026	U-21973 AADG-2.7a-71 2026 Summit City CAP Model - Final
W Cadillac Rd	2026	U-21973 AADG-2.7a-72 2026 W Cadillac Rd CAP Model - Final
Yankee Rd	2026	U-21973 AADG-2.7a-73 2026 W Yankee Rd CAP Model - Final
5 Mile	2026	U-21973 AADG-2.7a-74 2026 5 Mile CAP Model - Final

Attachment: See above table for list of attachments.

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-4.4a	
Respondent: J. L. Huffman	
Page: 1 of 1	

Question: For each of the past five calendar years (2021, 2022, 2023, 2024, and 2025), please provide the following information, broken down by customer class (residential heating, residential non-heating, commercial, and industrial), in a single spreadsheet with each year on a separate tab:

a. The total number of new gas service connections;

Answer: The Company does not perform analysis beyond the residential and commercial customer classes. Accordingly, information for other customer classes is not available. In addition, the Company does not have the requested information available for years prior to 2023. Please see the table below for the available information.

Year	Residential Connections	Commercial Connections
2023	9,190	800
2024	10,208	860
2025	8,615	831

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-4.4b	
Respondent: J. L. Huffman	
Page: 1 of 1	

Question: For each of the past five calendar years (2021, 2022, 2023, 2024, and 2025), please provide the following information, broken down by customer class (residential heating, residential non-heating, commercial, and industrial), in a single spreadsheet with each year on a separate tab:

b. The total number of connections that received a line extension allowance covering 100% of the connection cost (i.e., zero CIAC);

Answer: The Company does not have the data prior to 2024, please see table below for years 2024 and 2025.

Year	Number of Connections (zero CIAC)
2024	5,403
2025	4,817

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-4.4c	
Respondent: J. L. Huffman	
Page: 1 of 1	

Question: For each of the past five calendar years (2021, 2022, 2023, 2024, and 2025), please provide the following information, broken down by customer class (residential heating, residential non-heating, commercial, and industrial), in a single spreadsheet with each year on a separate tab:

c. The total number of connections that required a customer CIAC;

Answer: The Company does not have the data prior to 2024, please see table below for years 2024 and 2025.

Year	Number of Connections (Required CIAC)
2024	5,665
2025	4,627

Attachment: None

MPSC Case No: U-21973
Requester: Ann Arbor
Question No.: AADG-4.4d
Respondent: J. L. Huffman
Page: 1 of 1

Question: For each of the past five calendar years (2021, 2022, 2023, 2024, and 2025), please provide the following information, broken down by customer class (residential heating, residential non-heating, commercial, and industrial), in a single spreadsheet with each year on a separate tab:

d. The total cost of all service extensions (in dollars);

Answer: The Company does not track costs separately for the customer classes. Assuming the “total cost of all service extensions” question refers to the total new service installation gross cost, please see the table below:

Year	Gross New Service Cost
2021	$36.3 M
2022	$41.2 M
2023	$38.5 M
2024	$39.5 M
2025	$39.1 M

This does not include EUT or community expansion data.

Attachment: None

MPSC Case No: U-21973
Requester: Ann Arbor
Question No.: AADG-4.4e
Respondent: J. L. Huffman
Page: 1 of 1

Question: For each of the past five calendar years (2021, 2022, 2023, 2024, and 2025), please provide the following information, broken down by customer class (residential heating, residential non-heating, commercial, and industrial), in a single spreadsheet with each year on a separate tab:

e. The total CIAC collected (in dollars); and

Answer: The Company does not track CIAC separately for the customer classes. Assuming the “total CIAC collected” question refers to the total new service installation CIAC, please see the table below:

Year	New Service CIAC
2021	($1.7 M)
2022	($1.7 M)
2023	($1.9 M)
2024	($1.6 M)
2025	($4.0 M)

This does not include EUT or community expansion data.

Attachment: None

MPSC Case No: U-21973
Requester: Ann Arbor
Question No.: AADG-4.4f
Respondent: J. L. Huffman
Page: 1 of 1

Question: For each of the past five calendar years (2021, 2022, 2023, 2024, and 2025), please provide the following information, broken down by customer class (residential heating, residential non-heating, commercial, and industrial), in a single spreadsheet with each year on a separate tab:

f. The total amount added to rate base for service extensions (total extension cost minus total CIAC collected, in dollars).

Answer: The Company does not track total costs CIAC separately for the customer classes. Assuming the “total amount added to rate base for service extensions” question refers to the total net new service installation, please see the table below:

Year	Net New Service Cost
2021	$34.6 M
2022	$39.5 M
2023	$36.6 M
2024	$37.9 M
2025	$35.1 M

This does not include EUT or community expansion data.

Attachment: None

Table 15. Natural gas delivered to consumers by sector, 2020-2024, and by state and sector, 2024

Year and state/district	Residential Volume (million cubic feet)	Residential Consumers	Commercial Volume (million cubic feet)	Commercial Consumers	Industrial Volume (million cubic feet)	Industrial Consumers
2020 Total	4,674,456	71,540,659	3,162,664	5,627,762	8,212,977	184,466
2021 Total	4,716,658	71,951,957	3,289,076	5,613,615	8,374,672	182,207
2022 Total	4,964,255	72,525,043	3,510,617	5,621,186	8,529,076	181,002
2023 Total	R4,524,345	R73,275,155	R3,330,971	R5,653,260	R8,552,725	R178,477
2024 Total	**4,389,004**	**73,719,064**	**3,317,883**	**5,658,114**	**8,579,761**	**177,803**
Alabama	29,494	799,428	25,373	70,773	226,400	3,724
Alaska	21,308	143,614	16,788	14,758	66,641	8
Arizona	41,311	1,395,584	36,678	60,067	23,097	373
Arkansas	27,566	568,727	52,473	70,098	106,646	875
California	419,503	11,428,636	286,061	444,777	581,570	33,610
Colorado	128,826	1,937,980	58,659	157,953	92,175	9,374
Connecticut	47,637	597,512	55,698	63,419	20,992	2,655
Delaware	11,058	203,443	10,379	14,815	29,115	161
District of Columbia	10,279	153,561	14,266	10,040	0	0
Florida	20,320	945,906	67,594	76,413	127,554	434
Georgia	131,498	1,915,244	55,379	130,937	156,496	2,433
Hawaii	616	28,624	2,298	2,962	79	5
Idaho	33,166	475,518	25,926	46,701	36,548	559
Illinois	344,460	4,002,563	208,972	300,510	254,936	22,462
Indiana	133,326	1,866,080	83,829	167,336	395,827	4,665
Iowa	55,780	969,793	49,038	104,831	257,147	1,584
Kansas	53,745	892,739	39,698	86,982	136,487	7,422
Kentucky	41,760	795,860	35,332	89,047	134,579	1,897
Louisiana	31,709	927,737	29,246	58,579	1,187,548	926
Maine	2,960	42,989	9,163	14,817	19,985	162
Maryland	73,468	1,210,355	69,167	79,140	15,152	1,142
Massachusetts	112,216	1,604,279	104,609	138,545	43,873	10,916
Michigan	273,737	3,441,467	153,662	265,871	153,786	5,830
Minnesota	118,952	1,663,597	96,432	146,534	150,968	2,090
Mississippi	19,315	425,053	19,467	46,419	147,102	671
Missouri	85,348	1,461,770	60,020	116,967	67,994	2,969
Montana	21,032	295,415	25,671	40,911	27,312	346
Nebraska	33,466	560,551	32,389	61,105	107,961	5,257
Nevada	44,066	966,710	32,129	48,582	20,184	240
New Hampshire	6,910	116,692	8,978	20,190	9,729	210
New Jersey	219,880	2,839,369	142,821	238,235	61,317	5,988
New Mexico	35,812	619,406	27,496	51,890	15,601	545
New York	400,445	4,617,162	283,916	420,345	83,773	6,092
North Carolina	68,777	1,444,353	67,631	134,917	117,968	2,678
North Dakota	11,624	158,611	15,357	26,150	45,212	250
Ohio	247,246	3,501,459	162,089	266,603	323,260	6,223
Oklahoma	53,477	989,595	42,060	99,333	224,269	3,155
Oregon	44,910	809,918	30,228	84,777	55,195	1,171
Pennsylvania	211,663	2,895,337	157,975	252,047	236,818	4,242
Rhode Island	17,651	253,412	11,663	25,023	6,993	281
South Carolina	33,367	837,026	26,402	63,268	95,257	1,503
South Dakota	12,272	212,508	11,810	28,125	46,352	564
Tennessee	66,371	1,252,232	57,209	141,060	161,596	2,553
Texas	197,086	5,308,705	193,514	343,327	2,033,424	6,718
Utah	74,108	1,102,955	45,741	75,391	36,462	385
Vermont	3,539	49,358	6,844	6,280	2,061	14
Virginia	75,246	1,303,910	69,823	104,747	103,866	951
Washington	84,518	1,287,447	58,961	109,130	78,238	3,282
West Virginia	20,958	336,511	21,726	35,542	43,228	91
Wisconsin	123,088	1,887,729	106,440	179,685	141,541	8,032
Wyoming	12,137	174,634	12,802	22,160	69,447	85

See footnotes at end of table.

Year and state/district	Vehicle fuel Volume (million cubic feet)	Electric power Volume (million cubic feet)	Delivered to consumers Volume (million cubic feet)	Heating value[a] (British thermal units per cubic foot)
2020 Total	49,141	11,631,723	27,730,961	1,037
2021 Total	54,500	11,228,587	27,663,493	1,037
2022 Total	64,791	12,091,546	29,160,286	1,036
2023 Total	R60,130	R12,940,889	R29,409,060	1,036
2024 Total	**63,626**	**13,476,447**	**29,826,721**	**1,037**
Alabama	44	459,107	740,418	1,031
Alaska	1	26,742	131,479	1,003
Arizona	1,564	419,141	521,792	1,027
Arkansas	79	184,459	371,222	1,023
California	33,985	566,863	1,887,982	1,038
Colorado	358	141,984	422,002	1,056
Connecticut	315	174,768	299,410	1,030
Delaware	5	27,465	78,021	1,034
District of Columbia	290	--	24,835	1,029
Florida	7,249	1,454,448	1,677,166	1,027
Georgia	1,421	404,513	749,307	1,031
Hawaii	NA	--	2,994	918
Idaho	21	52,957	148,618	1,032
Illinois	177	208,972	1,017,517	1,044
Indiana	1,503	288,446	902,931	1,056
Iowa	2	62,210	424,175	1,069
Kansas	587	51,272	281,788	1,034
Kentucky	1	140,072	351,745	1,053
Louisiana	267	403,842	1,652,611	1,022
Maine	*	42,652	74,760	1,043
Maryland	497	103,050	261,334	1,038
Massachusetts	133	118,112	378,943	1,030
Michigan	99	425,731	1,007,015	1,055
Minnesota	441	113,877	480,670	1,068
Mississippi	7	433,118	619,009	1,026
Missouri	106	84,220	297,688	1,023
Montana	*	9,933	83,948	1,058
Nebraska	266	13,742	187,824	1,057
Nevada	1,338	182,674	280,391	1,044
New Hampshire	*	31,758	57,375	1,035
New Jersey	934	223,864	648,816	1,038
New Mexico	420	99,797	179,126	1,025
New York	838	509,646	1,278,619	1,033
North Carolina	894	430,803	686,073	1,038
North Dakota	*	25,139	97,333	1,066
Ohio	1,575	594,647	1,328,816	1,064
Oklahoma	1,674	381,489	702,969	1,033
Oregon	3	174,445	304,781	1,070
Pennsylvania	1,541	996,166	1,604,162	1,037
Rhode Island	85	64,922	101,314	1,028
South Carolina	90	176,210	331,327	1,033
South Dakota	0	18,669	89,103	1,086
Tennessee	459	117,490	403,125	1,030
Texas	2,712	2,121,502	4,548,238	1,018
Utah	177	87,117	243,604	1,047
Vermont	14	8	12,465	1,044
Virginia	886	436,811	686,633	1,046
Washington	240	122,986	344,942	1,094
West Virginia	41	31,242	117,195	1,078
Wisconsin	281	188,769	560,118	1,045
Wyoming	8	48,600	142,994	1,056

[a] Heating value is the average number of British thermal units per cubic foot of natural gas as determined from tests of fuel samples.
[*] Volume is less than 500,000 cubic feet.
[--] Not applicable.
[NA] Not available.
[R] Revised data.
Source: U.S. Energy Information Administration (EIA), Form EIA-176, *Annual Report of Natural and Supplemental Gas Supply and Disposition*; Form EIA-886, *Annual Survey of Alternative Fueled Vehicles* (2017); Form EIA-923, *Power Plant Operations Report*; and EIA estimates based on historical data.
Note: Totals may not equal sum of components because of independent rounding and/or withheld data. Vehicle fuel estimates include volumes sent directly to fueling stations and end-users, as well as company fleets owned or fueled by natural gas distributors. In instances where industrial or commercial end-users fuel their own natural-gas-powered fleets, those volumes are categorized as industrial or commercial, respectively.

Table 19. Number of natural gas residential consumers by type of service and state, 2023-2024

	2023			2024		
State or district	Onsystem sales	Transported for other companies	Total	Onsystem sales	Transported for other companies	Total
Alabama	R796,695	0	R796,695	799,428	0	799,428
Alaska	141,834	0	141,834	143,614	0	143,614
Arizona	1,376,394	2	1,376,396	1,395,582	2	1,395,584
Arkansas	573,138	0	573,138	568,727	0	568,727
California	R10,978,089	381,723	R11,359,812	11,034,731	393,905	11,428,636
Colorado	1,914,414	0	1,914,414	1,937,980	0	1,937,980
Connecticut	591,473	1,104	592,577	596,461	1,051	597,512
Delaware	199,186	0	199,186	203,443	0	203,443
District of Columbia	137,119	17,220	154,339	136,894	16,667	153,561
Florida	R892,383	R20,979	R913,362	924,240	21,666	945,906
Georgia	R341,137	1,564,826	R1,905,963	344,044	1,571,200	1,915,244
Hawaii	28,917	0	28,917	28,624	0	28,624
Idaho	465,632	0	465,632	475,518	0	475,518
Illinois	3,779,176	210,606	3,989,782	3,806,252	196,311	4,002,563
Indiana	1,790,919	56,706	1,847,625	1,812,064	54,016	1,866,080
Iowa	964,784	0	964,784	969,793	0	969,793
Kansas	R888,834	45	R888,879	892,694	45	892,739
Kentucky	R782,140	11,451	R793,591	785,154	10,706	795,860
Louisiana	R924,584	0	R924,584	927,737	0	927,737
Maine	R41,717	0	R41,717	42,989	0	42,989
Maryland	1,036,990	168,808	1,205,798	1,070,937	139,418	1,210,355
Massachusetts	1,586,498	16,720	1,603,218	1,590,037	14,242	1,604,279
Michigan	3,299,692	122,240	3,421,932	3,326,130	115,337	3,441,467
Minnesota	1,644,691	0	1,644,691	1,663,597	0	1,663,597
Mississippi	R450,436	0	R450,436	425,053	0	425,053
Missouri	1,453,603	0	1,453,603	1,461,770	0	1,461,770
Montana	292,147	653	292,800	294,939	476	295,415
Nebraska	477,013	68,667	545,680	491,778	68,773	560,551
Nevada	951,630	0	951,630	966,710	0	966,710
New Hampshire	116,607	0	116,607	116,692	0	116,692
New Jersey	2,887,624	71,800	2,959,424	2,772,727	66,642	2,839,369
New Mexico	614,987	97	615,084	619,312	94	619,406
New York	4,346,361	255,234	4,601,595	4,381,170	235,992	4,617,162
North Carolina	1,414,844	0	1,414,844	1,444,353	0	1,444,353
North Dakota	155,242	0	155,242	158,611	0	158,611
Ohio	619,948	2,885,446	3,505,394	588,489	2,912,970	3,501,459
Oklahoma	R985,379	0	R985,379	989,595	0	989,595
Oregon	804,961	0	804,961	809,918	0	809,918
Pennsylvania	R2,552,761	336,155	R2,888,916	2,569,612	325,725	2,895,337
Rhode Island	249,454	0	249,454	253,412	0	253,412
South Carolina	808,870	0	808,870	837,026	0	837,026
South Dakota	208,985	0	208,985	212,508	0	212,508
Tennessee	R1,231,961	0	R1,231,961	1,252,232	0	1,252,232
Texas	R5,203,200	307	R5,203,507	5,308,408	297	5,308,705
Utah	1,081,582	0	1,081,582	1,102,955	0	1,102,955
Vermont	49,381	0	49,381	49,358	0	49,358
Virginia	1,223,828	74,469	1,298,297	1,234,542	69,368	1,303,910
Washington	1,279,608	0	1,279,608	1,287,447	0	1,287,447
West Virginia	R338,582	1	R338,583	336,511	0	336,511
Wisconsin	1,861,280	1	1,861,281	1,887,728	1	1,887,729
Wyoming	115,424	57,761	173,185	116,016	58,618	174,634
Total	**R66,952,134**	**R6,323,021**	**R73,275,155**	**67,445,542**	**6,273,522**	**73,719,064**

[R] Revised data.
Source: U.S. Energy Information Administration (EIA), Form EIA-176, *Annual Report of Natural and Supplemental Gas Supply and Disposition*.

Some of the residential and commercial consumers reported for 2020 through 2024 may have been double counted. Please see Appendix A for more information.

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-2.8a	
Respondent: J. L. Huffman	
Page: 1 of 1	

Question: Please provide responses to the following requests regarding Customer Growth Projections and Assumptions.

a. Please provide the basis for projecting 10,041 (2025), 11,895 (2026), and 11,846 (2027) new sales customer attachments as referenced in Witness Huffman's testimony at Q93, including: a) Historical attachment rates for the past 10 years; b) The methodology used to develop these projections; c) Any market research or studies supporting these projections; d) Sensitivity analysis showing attachment rates under alternative assumptions.

Answer: Please refer to attachment *NDA U-21973 MECCUBDG-3.9a Attachment - Historical and Projected by Category - 07.2025 Rate Case Update* for the information responsive to subparts (a) through (c). This attachment includes the historical attachment data, the methodology used to develop the projected customer attachment levels, and the supporting assumptions relied upon for these projections. With respect to subpart (d), the Company does not perform a formal sensitivity analysis on customer attachment projections.

Attachment: None

MPSC Case No: U-21973	
Requester: Ann Arbor	
Question No.: AADG-2.9fi-iii	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: Please provide responses to the following requests regarding climate goals and decarbonization strategy.

f. In the last rate case Dr. Bente Villadsen testified on behalf of the Company that, “DTE Gas is facing increasing risk from state decarbonization policies.” Case No. U-21291, 4 Tr 2495.

i. Does DTE Gas still believe it faces business risk related to decarbonization?

ii. If the answer to the previous question is yes, has the Company made any effort to quantify that risk or incorporate it into future planning?

iii. If the answer to subpart (i) is no, what changed between the last rate case and the current rate case that led the Company to the conclusion that it no longer faces a business risk due to decarbonization?

Answer: DTE Gas objects for the reason that the information requested is not relevant or proportional to the needs of the case. Subject to this objection, and without waiving this objection, DTE Gas would answer as follows:

i. Refer to Q/A 35 of my direct testimony which states, “DTE Gas acknowledges that State or Federal legislative and regulatory developments could impact natural gas demand and DTE Gas’s capital plans. DTE Gas is prepared to identify the most effective method for delivering safe and affordable natural gas to our customers in alignment with any legislative or regulatory developments. DTE Gas is not currently aware of any proposed legislation or regulation that would materially impact its current business.”
ii. See response to part i.
iii. See response to part i.

Attachment: None

Co-Respondent(s): Legal

Cutting These Subsidies Could Save States Millions of Dollars

By Mike Henchen and Joe Dammel
August 27, 2025

Across the country, many utilities, regulators, and policymakers are looking for solutions to lower energy bills while advancing a transition to cleaner energy. One solution is gaining momentum, with action in eight states and counting: phasing out utilities' gas line extension allowances. These are free allowances for new gas utility connections that help expand the gas system, funded through utility bills -- putting the cost on existing customers.

How the process works

1. A developer constructs a new building or neighborhood and applies to the utility for a connection to the natural gas system.

2. The utility assesses the new building's location relative to its existing infrastructure and, in most cases, connects the new buildings to the gas system at little or no cost to the developer.

3. The costs then appear in everyone's gas utility bills, typically as part of the delivery charge.

Details vary by state and utility, and if it's especially expensive to connect a building, that new customer may have to contribute to the cost. But in general, new customers pay little or nothing to connect to natural gas service. Instead, the entire customer base is forced to collectively share those costs.

Gas utilities have relied on existing customers to subsidize their expansion for decades. The same approach is used for connecting new buildings to the electric grid, and it has helped streamline universal access to electricity. But in recent years, utility regulators and policymakers have started reconsidering this approach for natural gas. As demand grows for electric heat pumps and water heaters and as states set new goals to grow alternatives to gas equipment, line extension practices now pose a new risk: they add investment to a gas system that could see declining use, which could drive up rates even higher over time.

Why regulators are reconsidering this policy

Historically, line extension allowances were generally justified because there was an expectation that new gas customers would stay connected for decades and pay enough in gas bills to cover the upfront investment other customers made on their behalf. Over time, their payments would help fund future line extensions, keeping the cycle going as the system grew.

But now that model is breaking down. As more customers switch from gas to electric alternatives -- or simply use less gas through efficiency upgrades, hybrid gas-electric heating, or limiting gas use to smaller appliances -- the revenue from new customers often falls short of covering their connection costs. As a result, new customers may not recover connection costs, leaving everyone else to cover the gap.

Eight states are taking action

Over the past three years, utility regulators or legislators in eight states have taken action to reduce or phase out gas line extension allowances. Their goal: to protect customers from excess costs in their gas bills and, in many cases, to better align utility practices with state climate policies that could drive large reductions in gas use.

Starting in 2022, the California Public Utilities Commission issued an order phasing out line extension allowances for gas utilities across the state. The Washington State regulator adopted a plan to phase out these allowances for one of its utilities and has since done the same for two others. In Colorado, the legislature directed the utility regulator to take a similar action. Oregon followed suit with regulatory decisions in 2023 and 2024. The Minnesota Public Utilities Commission approved modest changes to utility allowances in three rate case settlements and is now considering broader changes across the state. Most recently, the Maryland and Massachusetts regulators have stated their intent to eliminate gas line extension allowances, and the state legislature in New York passed a bill doing the same; in these cases, more action is needed to finalize the changes.

The finding: potential $750 million in savings annually

Each of these actions means lower utility bills in each of these states. These vary based on the pace of new gas system connections, the cost of these connections, and how generous the original policy was.

Altogether, these changes could cut utility costs by $750 million per year. In some cases, these rule changes overlap with other policies that contribute to the same savings. For instance, new gas connections in New York state will also decline due to the state's new all-electric building standard.

Early evidence suggests that these policy changes are influencing market decisions to build without gas, rather than simply shifting the cost of gas connections to new customers. California's largest combined gas and electric utility, PG&E, reported that in 2023, a large majority -- 72 percent for residential buildings and 91 percent for non-residential -- of new line extension requests were for electric service only with no gas connection. This is much larger than the historical trend, as only 8-9 percent of PG&E residential customers are all-electric today. Similarly, the policy change in Colorado helped enable a plan from Lennar, a major homebuilder, to build 1,500 new homes with geothermal heating and no natural gas service, in partnership with Dandelion. In this case, the phaseout of the subsidy for gas service helped tip the business case for this investment toward an electric alternative.

Action on the horizon

More states are taking a closer look at this opportunity for gas system utility savings. Regulators in Illinois have identified this issue for consideration in ongoing planning, and the Minnesota Public Utilities Commission is considering whether to build on the small changes already executed with more sweeping reductions in line extension allowances. And some of the states mentioned above still have these changes in the works. For instance, in Massachusetts and Maryland, regulators are holding open proceedings to implement these changes, and a New York bill to phase out line extension allowances is headed to the governor's desk.

As energy prices rise and more buildings switch to electric systems, this policy shift is gaining traction. It's a straightforward way to ease utility bills and support a cleaner, more affordable energy future.

expected revenues for the utility and the line cost, the average advanced contribution per customer might come to, say, $10,000. Just like other investments that payoff in the end, consumers may forgo them because of the high initial cost.[101] Many households, for example, may decide they cannot afford to take $10,000 from their savings at this time, or take out a loan of that amount.[102]

Perhaps, then, just like subsidizing customers for energy-efficiency investments, the utility could have existing customers pay some portion of the advanced contributions. The utility could argue that fuel switching would be net beneficial but unaffordable to some prospective customers. Why not then increase slightly the rates of existing customers so that prospective customers would switch to natural gas? One answer is that it may be more appropriate for the government to provide financial assistance to new customers. Especially if the line extension contributes to economic development in the rural area, funding with taxpayer money might be the preferred course. Another answer is that, instead of charging existing customers a higher rate, the utility could think of creative ways for new customers to pay their advanced contribution in a more accommodating way. For example, the utility could allow new customers to pay back their special financial contribution over several years, lessening their immediate financial burden.

3. When a subsidy is bad policy

Some readers might conclude that the above example fails to justify a subsidy. Even if one agrees that a problem exists, the "subsidy" solution may be inferior to other actions. In other words, subsidization can represent a blunt and cost-inefficient response to achieve some social objective.

One seemingly preferred action would be for the utility to allow new customers to pay the $5,000 over a number of years. Prospective customers then might find switching to gas, which would be in their long-term interest, affordable. As a rule, efficient fuel switching requires that those who benefit pay the full cost of converting furnaces and other equipment, plus the new lines. Commissions and other policymakers should regard this outcome as the default solution, unless evidence supports some financial assistance from either existing customers or taxpayers. Thus, they should exercise caution in approving subsidies for customers who switch to natural gas. 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:

1. It is unfair to existing customers because they are involuntarily funding new customers at no benefit or less-than-commensurate benefits to them.

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[101] One example that regulators can relate to is energy-efficiency investments.

[102] In today's tight credit market, households may find it difficult to get loan approval.

2. It is also economically inefficient if it induces additional energy consumers to switch to natural gas when they otherwise would not have if they had to pay the full cost of line extensions.

3. Subsidies also may distort competition among energy sources. By offering new gas customers subsidies, suppliers of oil, propane, and electricity would be at a disadvantage.

4. Even with public benefits, subsidies funded by existing customers might not constitute the most cost-effective approach for increasing the number of new gas customers and gas consumption. Funding from taxpayers or utility shareholders might create less inefficiency.

5. Even if policymakers can justify subsidies for fuel switching and line extensions, they need to ask which forms would be most cost-effective and create the least distortion.

Some readers may justify subsidies for fuel switching to natural gas similarly to the justifications used for governmental subsidies to rural electric cooperatives. Those subsidies assisted in the expansion of electric service to areas that privately owned utilities would not find financially viable. One difference is that rural people and businesses would not have access to electricity without the cooperatives. Yet prospective natural gas customers do have access to some other energy source (even if it is not their preferred source) to meet their demands. The main reason for switching would be to save money on energy, not to have available some new end-use service.

K. Role of local, regional, and state governments

Notwithstanding the previous section's discussion, some people would argue that the public benefits from fuel switching justify governmental assistance. These benefits are in addition to the benefits that energy consumers directly receive when they switch to natural gas. They include a cleaner environment, bolstering economic development, and national security.[103] A state can include as part of its energy strategy the promotion of customers switching to natural gas. The rationale for state financial assistance is that: (1) market forces are not accounting for the public benefits or (2) market barriers are stifling the amount of switching. Either condition may result in suboptimal levels of fuel switching.

[103] The positive effects, especially a cleaner environment and national security, apply more to switching from oil to natural gas. The environmental effects of propane are comparable to those for natural gas. When released into the atmosphere, and unlike natural gas, propane has no greenhouse gas effect. Domestic production accounts for about 98 percent of the propane consumed in the U.S., avoiding any national security problems.

EXECUTIVE SUMMARY

Introduction

This research evaluates scenarios that achieve an economywide reduction in greenhouse gas (GHG) emissions of 40 percent by 2030 and 80 percent by 2050 from 1990 levels. California has also set a carbon-neutral target for 2045, which is not directly evaluated as part of this research.

Natural gas is an integral part of California's energy system, including in buildings, industry, and electric generation. Nearly 80 percent of all homes in California are connected to the natural gas system. Californians spend nearly $14 billion per year on gas, both to use the gas itself in buildings, industry, and electric generation and to maintain and operate the gas system.

To meet California's climate goals, use of fossil fuels like natural gas will need to decrease by 80 percent or more by 2050. Zero-carbon electricity requirements under Senate Bill 100 (de León, Chapter 312, Statutes of 2018) will lead to a substantial reduction in annual demands for natural gas in electric generation. Efforts to reduce built environment emissions, particularly strategies to reduce GHG emissions from natural gas use in buildings via efficiency or electrification, could also lead to reductions in natural gas demand over time. However, no Energy and Environmental Economics, Inc. (E3) study has yet identified a strategy that eliminates the use of pipeline gas altogether, since zero carbon gas alternatives can replace natural gas in the pipeline. Every scenario leaves residual gas demands in industry, while others allow gas usage in the buildings or transportation sector.

The implication is that any scenario that meets California's climate policy goals uses some amount of renewable natural gas (RNG). The research team defines RNG as climate-neutral gaseous fuels and uses it as an umbrella term to encompass four fuels, including 1) biomethane produced from anaerobic digestion of biomass wastes, 2) biomethane produced from gasification of biomass wastes and residues, 3) climate-neutral sources of hydrogen gas, and 4) methane produced synthetically from a climate-neutral source of carbon and hydrogen. (*Gasification* is a technology that converts carbon-containing materials, including biomass, into synthetic gas.) This study finds that, at scale, the costs of these fuels far exceeds that of natural gas. Relatively inexpensive portions of biomethane RNG are limited in quantity, so it may be preferable to reserve the use of these supplies for more energy-intensive, trade-exposed sectors of the California economy that do not have efficient, electrified substitutes readily available.

The question of the future of retail gas – defined here primarily as gas usage in the buildings sector – hinges on cost and consumer acceptance. Electrification, the use of electricity in place of other fuels, appears to be a cost-effective strategy for some consumers today. The addition of relatively high cost RNG into the gas pipeline would improve the economics of electrification in buildings. If demand for natural gas in California falls dramatically because of some combination of policy and economically driven electrification, the fixed costs to maintain and operate the gas system will be spread over a smaller number of gas sales and, ultimately, will increase costs for remaining gas customers. This outcome raises the possibility of a feedback effect where rising gas rates caused by electrification spur additional electrification. Such a feedback effect would threaten the financial viability of the gas system, as well as raise substantial equity concerns over the costs that remaining gas system customers would face. Given these risks, building electrification could serve as a risk-reduction strategy to protect low-income and vulnerable communities from future gas rate increases. However, achieving meaningful levels of building electrification will require changes to both new construction practices as well as retrofits of the existing building stock. Consumer adoption of building electrification technologies is one the largest barriers to achieving the emissions reductions from the building sector described in the High Building Electrification scenario.

If building electrification is delayed, missing the lower-cost opportunities for all-electric new construction and replacement of equipment upon failure, there is a greater risk that expensive early retirement of equipment may be needed, or that the climate goals could be missed. Furthermore, there are significant technology and cost risks of commercializing large quantities of renewable natural gas compared to electrifying buildings, which relies on technologies that are commercialized today.

This analysis, and work by others, suggests that achieving the state's ambitious climate goals is possible, but is far from assured, requiring rapid and near-term transformation in all sectors of the economy, as well as widespread consumer adoption of low-carbon technologies, fuels and practices.

Project Purpose

The future of natural gas, in the context of meeting the state's climate goals, is an important question for natural gas and electric ratepayers, as well as for policymakers interested in enabling California's clean energy transition. The research team takes a forward-looking view of future gas use in California, focusing on implications for, and strategies to protect, ratepayers.

To do that, this research evaluates the potential cost, energy infrastructure, and air quality implications of achieving the state's economywide climate goals, with an emphasis on:

1) Technology options to decarbonize the natural gas system. Specifically, what are the costs, and resource potential, for renewable natural gas technologies, including biomethane, hydrogen gas and climate-neutral synthetic natural gas?
2) Implications for natural gas customers. What are the potential changes in natural gas demand, rates, and bills associated with meeting California's climate goals? What are potential strategies to address the equity implications of changes in natural gas rates and utility bills while maintaining the safety and financial viability of the gas system?
3) Outdoor air quality and public health. What are the outdoor air quality and health benefits of meeting California's climate goals, and what are the air quality implications of reducing GHG emissions from natural gas?

The purpose of this research is not to define or recommend policies nor provide a definitive set of conclusions about California's energy future. Instead, the research team strives to use the best information available today to provide insights about how the decisions made today could affect the state's future choices. Those insights will inform researchers and policy makers on potential next steps toward achieving the state's clean energy transition.

Project Approach

E3 and the Advanced Power and Energy Program at the University of California, Irvine, (UCI) comprise the research team.

E3 led the development of economywide GHG scenarios using the California PATHWAYS model, as well as a detailed evaluation of the long-term natural gas rate and bill impacts of those scenarios. The California PATHWAYS model is a technoeconomic model of the state's energy consumption and GHG emissions that has been used and updated by California energy agencies since 2014.

The GHG mitigation scenarios evaluated in the PATHWAYS model do not represent forecasts of what is likely to happen, but rather represent "back-casts" of what kinds of changes, on what timeframe, may be necessary to meet a long-term climate goal.

E3's natural gas utility revenue requirement tool estimates how changes in natural gas demand throughput and changes in gas commodity costs could affect natural gas rates, both over time and by customer class. The revenue requirement tool was developed specifically for this project and benefited from insights and detailed feedback provided by the Southern California Gas Company (SoCalGas) and Pacific Gas and Electric (PG&E) and relied exclusively on publicly available data. Neither SoCal Gas nor PG&E was asked to endorse the revenue requirement tool or the study findings, which remain entirely the responsibility of the study team.

The UCI Advanced Power and Energy Program team worked with E3 to develop bottom-up estimates of RNG technology production costs using conservative and optimistic assumptions about technology learning curves, as well as other key input parameters.

The UCI team also led the analysis of outdoor air quality and health impacts of achieving the state's climate goals. The UCI team used the California PATHWAYS scenarios as the basis for assumptions about future changes in energy demand by fuel type and equipment type over time. The UCI team employed a sophisticated set of air quality modeling tools, including Sparse Matrix Operator Kerner Emissions (SMOKE) to resolve the emissions spatially by geography, the Community Multiscale Air Quality Modeling System (CMAQ) to simulate air quality, and the Environmental Benefits Mapping and Analysis Program (BenMAP) to estimate the health savings effects.

The project team benefited from in-kind labor contributions from the Sacramento Municipal Utilities District (SMUD) and SoCalGas, who both participated on the Technical Advisory Committee (TAC) and provided other data and feedback to the research team. SoCalGas also cofunded a portion of UCI's research. Other members of the TAC included representatives from PG&E; the California Air Resources Board; University of California at Riverside; University of California at Davis; the Natural Resources Defense Council; the Environmental Defense Council; Mitsui and Co.; and the Greenlining Institute. For a complete list of TAC members, see Appendix B.

Key areas of discussion and debate among TAC members and the research team included the following:

1. How to reflect the costs and uncertainties around wildfire risk in California?

2. How to assess the future resource potential for biomass and biofuels available to California?
3. How to reflect current state programs that encourage through incentives the use of biofuels, electricity, and hydrogen in the transportation sector, particularly the Low Carbon Fuel Standard?
4. How to characterize the most likely future trajectory for hydrogen gas and synthetic natural gas production costs?

Each one of these topics was evaluated in the course of this research as described in this report and in the Appendices. For a more detailed discussion of some of the "frequently asked questions" and comments about this report, see Appendix A.

Participation on the TAC was voluntary and in no way indicates that TAC members endorse the study conclusions. In addition to participating in the TAC meetings, the TAC members, as well as many other organizations and members of the public, submitted formal comments on the draft study findings, and again on the draft report. While all the comments provided by the TAC members and other stakeholders were considered, this research remains an independent research project, and the study authors are solely responsible for the contents of the report.

Project Results

This study evaluates the cost and resource potential for biomethane, hydrogen and synthetic natural gas, collectively, renewable natural gas. Of these three gases, biomethane is the most commercialized and is lowest cost, but is limited in availability based on sustainable sources of biomass feedstock. Hydrogen and synthetic natural gas could be produced with low-cost electricity that might otherwise be considered "over-supply" and curtailed, but the quantity of this low-cost electricity is far lower than the amounts of electricity that would be needed to produce large enough quantities of hydrogen and renewable natural gas to replace natural gas use in California. Hydrogen use in the natural gas pipeline is limited to 7 percent by energy, before costly pipeline upgrade costs would be incurred to transport higher concentrations of the gas. Even under optimistic cost assumptions, the blended cost of hydrogen and synthetic natural gas is 8 to 17 times more expensive than the expected price trajectory of natural gas.

Renewable natural gas is found to be a valuable, but relatively expensive from of carbon reduction. Relatively low-cost biomass feedstocks are limited in quantity, so lower-cost PATHWAYS scenarios allocate these limited feedstocks to sectors that are difficult to electrify, like aviation, industry, and trucking. The limited supply of and competing uses for biofuels mean that scenarios that maintain high volumes of gas throughput in buildings require hydrogen and synthetic natural gas to reduce emissions.

In all the long-term GHG reduction scenarios evaluated here, electrification of buildings, and particularly the use of electric heat pumps for space and water heating, leads to lower energy bills for customers over the long term than the use of renewable natural gas. Likewise, building electrification lowers the total societal cost of meeting California's long-term climate goals. The High Building Electrification scenario is lower cost than the No Building Electrification scenario in 2050 by $5 billion to $20 billion per year (in 2018 dollars). The primary reason for this cost difference is the cost of decarbonizing natural gas with renewable natural gas, relative to electrification buildings. Furthermore, in the No Building Electrification scenario, a larger amount of fossil fuel emissions remain in buildings, which means that more expensive GHG mitigation measures, such as additional zero-emission trucks, are needed elsewhere to meet the economywide climate goal.

This strategy, of leaving more fossil fuel emissions in the building sector in order to minimize the reliance on expensive RNG, may not be possible in a scenario that achieves the state's 2045 carbon-neutrality goal. Achieving carbon neutrality in buildings would likely increase the relative costs of high RNG scenarios, such as the no building electrification scenario, compared to scenarios relying on building electrification.

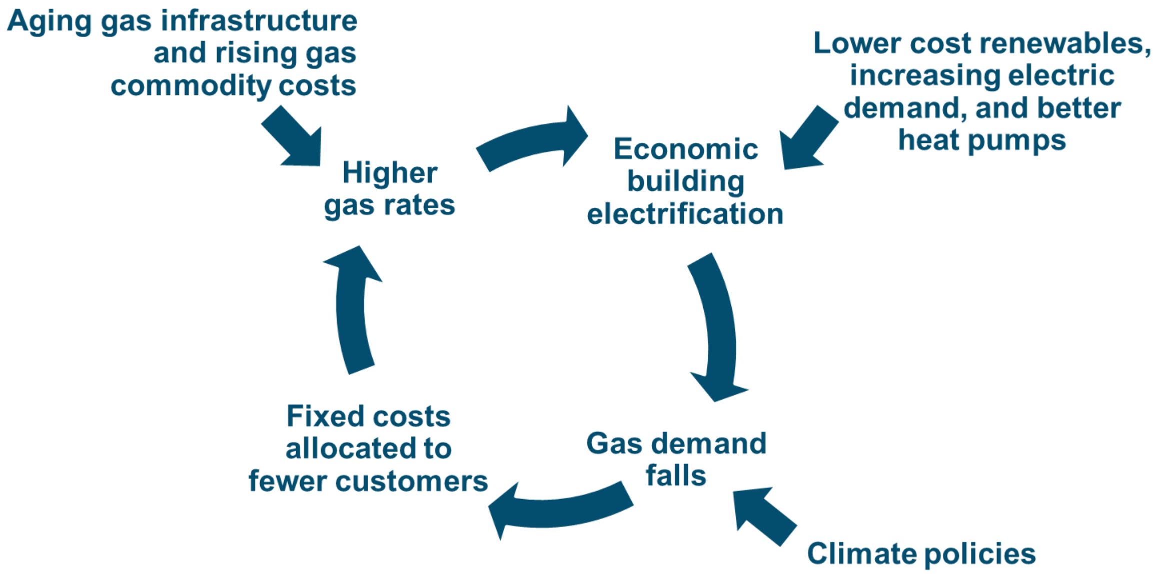
Building electrification is found to improve outdoor air quality and public health outcomes, particularly in the winter, when nitrogen oxide emissions create secondary fine particulate matter (PM 2.5) pollution in the Central Valley. Electrification in other sectors, including transportation and industry, also shows dramatic improvements in outdoor air quality.

In all scenarios, the cost of maintaining the electric grid, including the costs of wildfires and upgrades to the electric grid to prevent future wildfires, are expected to increase, even those scenarios with low building electrification. While is it uncertain what the magnitude of these electricity sector costs will be, wildfire adaptation costs are not expected to vary by scenario, so would not impact the net scenario costs, which are reported relative to the reference scenario. This study finds that the addition of new electric loads, in the form of electric vehicles and building electrification, helps mute these cost impacts on electric rates. Furthermore, these new electric loads offer the possibility to provide flexibility to the grid, which could help to reduce the cost of decarbonized electricity. Higher electricity costs will affect the relative customer economics of electricity versus RNG, so a wide range of potential electricity and gas system costs are explicitly evaluated. The economic results are found to be robust across a wide range of electricity and RNG costs.

In all of the scenarios evaluated here, some gas consumers will find it in their economic self-interest to electrify. Electrification is likely cost effective for large subsets of Californians today, so higher gas commodity costs only expand the set of end-uses and customer types that would find electrification advantageous. In any future where California meets its long-term climate goals, natural gas demand is likely to decline, putting upward pressure on gas rates and bills. That pressure may cause more customers to exit the gas system, as a feedback loop takes effect (Figure ES-1). The prospect of such a feedback loop makes it prudent for the state to begin considering strategies for managing the costs of the natural gas distribution system in California.

The decline in gas demand in all scenarios meeting the state's climate goals, and especially in the High Building Electrification scenario, poses significant challenges to maintaining equitable cost allocation. Residential customers pay most of the costs of the gas distribution system. The gas distribution system constitutes the majority of the book value of both California's major natural gas utilities. As residential customers exit the gas system, those costs are spread over a smaller quantity of throughput and number of customers, leading to increased rates for remaining customers. Absent a policy intervention, low-income customers who are less able to electrify may face a disproportionate share of gas system costs.

Figure ES-1: Outside Forces in the Natural Gas Delivery Sector Could Lead to Lower Gas Demand and Higher Rates in Future Greenhouse Gas Reduction Scenarios



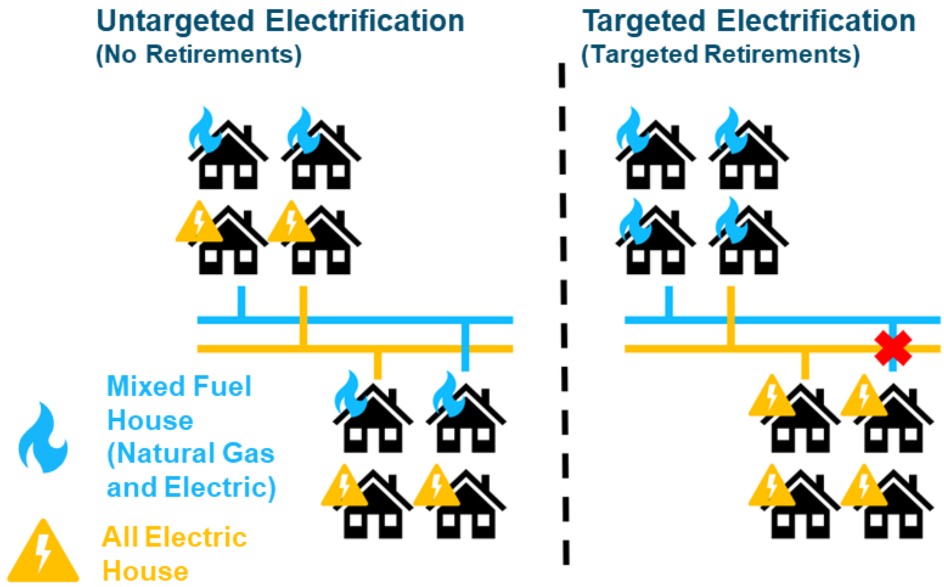
Source: E3

It is important for the state to consider a gas transition strategy to ensure that, even as gas demand falls, the system remains safe and reliable for the remaining gas customers while helping reduce future customer cost and utility bill impacts, as well as addressing equity challenges. Even in the High Building Electrification Scenario, which assumes a rapid transition to 100 percent of sales of all new water heaters and HVAC systems to electric heat pump equipment by 2040, there are still millions of gas customers remaining in California by 2050. Early retirement of gas equipment could speed the pace of this gas transition but would come with real economic costs that are difficult to estimate at this time. In addition, early retirement of gas equipment would likely face other challenges, including customer adoption barriers.

Given the long lifetimes of buildings and building equipment, a complete gas transition is likely to require decades in any scenario. For these reasons, this research evaluates potential gas transition strategies that aim to maintain reasonable gas rates, as well as the financial viability of gas utilities through the study period. Legal and legislative options, including strategies for a more rapid transition away from gas, are not evaluated.

A well-managed gas transition could enable cost reductions of gas infrastructure investments, as well as some reductions in gas system operations and maintenance costs that would be incurred in the absence of a gas transition strategy. Such a managed gas transition would likely require some amount of targeted or zonal electrification, to enable a reduction in the gas distribution infrastructure (illustrated on the right side of Figure ES-2). Without a managed gas transition and without any effort to target electrification, it would be difficult to reduce the size or scale of gas system investments and costs (illustrated on the left side of Figure ES-2). Additional research is needed to better understand the geographic scope, scale, pace, and limitations to reducing gas distribution system costs.

Figure ES-2: Two Gas System Futures With and Without Targeted Electrification



Source: E3

A further reason a structured gas transition is needed is that high-pressure gas transmission and underground gas storage systems may continue to serve important roles, even in a scenario with an 80 percent or higher reduction in GHG emissions. Those roles might include serving either natural gas or decarbonized gaseous fuels to remaining electric generation, industrial customers, compressed natural gas (CNG) trucks and other CNG transportation options, as well as potentially providing benefits via distributed hydrogen fuel cells. A comprehensive analysis of the role of distributed fuel cells or the uses for the bulk gas system in a carbon-neutral future is beyond the scope of this analysis and is an area that deserves further investigation. However, each of these uses would need to rely on an increasing share of RNG to meet the state's climate goals, rather than continued reliance on fossil natural gas.

A structured gas transition could help ensure the continued viability of gas infrastructure assets that the state needs to maintain reliable energy service, while phasing down investments in gas distribution assets that become too costly to maintain as demand for retail gas declines. If the results of this research are correct in concluding that retail gas in a low-carbon future is likely to be more expensive than building electrification, it raises a number of challenging questions and areas recommended for additional research. Key policy questions include the following:

- If demand for retail gas declines, how should the benefits and costs of a gas transition strategy be allocated among stakeholders?
- If demand for retail gas declines, how can California protect low-income residents and gas workers during a gas transition?

Key engineering questions around gas pipeline safety and costs remain as well. These questions include the following:

- To what degree can targeted electrification efforts safely reduce gas distribution expenditures?

- What is the cost of targeted electrification, considering the potential for early retirements of consumer equipment? A better understanding is needed of the real-world technical and economic options to reduce gas system expenditures. Pilots and real-world research could help identify the costs and options to launch targeted electrification in communities in such a way that would enable targeted retirements of the gas distribution system and consider the impacts on the electric distribution system of targeted electrification, along with the potential for cost savings on the gas distribution system.

Finally, more research is needed to identify the legal and regulatory barriers to implementing a gas transition strategy, along with targeted electrification programs. For example:

- Should natural gas companies be able to collect the entire value of their gas system assets through 2050 or beyond? Should shareholder return be affected in a gas transition strategy? How does the timing of a gas transition strategy affect the answer to these questions?
- Should California gas utilities' obligation to serve be redefined?

This research paper does not seek to make policy recommendations, but rather highlight key issues for further policy discussion. The paper also seeks to illuminate some of the implications of meeting the state's climate goals, with the goal that California's future is as equitable and well planned as possible.

Knowledge Transfer

The CEC has taken steps to ensure that a broad audience has the opportunity to comment on the draft results of this research. The Commission held a public staff workshop June 6, 2019. More than 30 unique public comments were filed to the docket. Additional public comment was solicited by the CEC on the draft report.

Some stakeholders have argued that California should move faster on meeting its climate goals compared to the scenarios evaluated in this study, phasing out the use of all natural gas as quickly as possible due to concerns over combustion emissions, indoor and outdoor air quality concerns, and the prospect of methane leakage—a high global warming potential gas. Other stakeholders have highlighted the uncertain mix of climate change impacts on the future costs of electricity in California. Wildfires, flooding, and extreme heat mean that the provision of reliable and low-cost energy services in the state is becoming more complex and challenging.

The research team envisions this project as a contribution to the continued conversation that stakeholders and policy makers will have over the next several years, as the state considers what steps will be needed to meet the goal of economywide carbon neutrality by 2045, and how to expedite a gas transition strategy that ensures an equitable transition to a low-carbon future for all California residents.

Benefits to California

This project highlights the need for long-term planning for the natural gas system in the context of meeting the state's climate goals. This project provides a long-term, scenario-based view to investigate how the natural gas system can help California meet its long-term GHG reduction goals. Specifically, this project benefits California by providing:

- Information to help lower the costs of meeting California’s climate goals and to inform technology research and investment. By taking a long-term view of the state’s climate goals and evaluating the role of the natural gas infrastructure in that future, this research allows the state to potentially avoid stranded assets in the gas system. Stranded assets are investments which are not used and useful, and for which the full investment cost cannot be recovered from ratepayers, triggering a premature write-down or devaluation. This project provides information about the potential for changes in natural gas demand and implications for future investments in the gas sector, the gas system rate base, natural gas prices (wholesale and retail), customers’ home energy bills, costs of GHG reduction, and capital and fuel costs by sector.
- Energy metrics to make better planning easier. Long-term scenarios provide information on economywide energy use by sector and industry, including energy demand for electricity and natural gas.
- Environmental and public health metrics. This project evaluates long-term, detailed criteria air emissions and pollutant levels statewide at a 4x4 kilometer grid within the context of meeting the state’s climate goals. By identifying scenarios that can provide cleaner air and improve public health, policy makers can develop policies to enable a future with cleaner air for Californians and particularly for environmental justice communities with a greater pollution burden.

Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL"), one of the oldest natural gas delivery systems in the United States, has been a cornerstone of Chicago's energy infrastructure for over 150 years. It has evolved alongside the city's shift from wood and coal to manufactured gas, and eventually to natural gas by the mid-20th century. Today, Peoples Gas – a subsidiary of the $44 billion energy holding company, WEC Energy Group, Inc. (WEC Energy) – serves nearly 900,000 customers, providing gas for heating, cooking, and industrial uses.

Since its acquisition by WEC Energy in 2015, Peoples Gas has delivered five consecutive years of record financial returns, with dividend payments to WEC Energy increasing more than fivefold, totaling $335 million in 2023. Central to these profits has been the company's **System Modernization Program (SMP)**, a multi-decade, multibillion-dollar initiative to replace much of the city's gas distribution network and upgrade the system's pressure. However, despite this strong record of profitability, the SMP has also introduced significant financial and regulatory risks. In November 2023, the Illinois Commerce Commission (ICC) paused the SMP, initiated an investigation into its reasonableness and prudence, disallowed recovery of $177 million in previously incurred capital costs, and initiated a multi-phased Future of Gas proceeding. These actions, alongside Illinois' broader push toward clean energy, highlight the increasing regulatory scrutiny facing gas utilities in a rapidly changing energy landscape.

Today, as a gas-only utility, Peoples Gas is particularly vulnerable to the financial risks posed by shifting customer preferences and decarbonization efforts that increasingly favor electrification. Notwithstanding its historical significance and critical role in the city's development, Peoples Gas now faces business threats that jeopardize the sustainability of its long-standing business model.

A. Scope of this report

This report examines the risks and uncertainties facing Peoples Gas, its investors, and its customers. It provides a comprehensive analysis that includes:

- **PGL's corporate and regulatory history.** We chart the evolution of Peoples Gas, the regulatory model set by the ICC, and the significant scrutiny the SMP has faced from numerous audits and investigations.
- **Evaluation of key business threats.** We evaluate the impact of three major threats:
  1. **Escalating delivery costs.** The increasing costs associated with replacing aging infrastructure, particularly in an industry now in the mature phase of its life cycle.
  2. **Clean energy policies.** Mandates and incentives from the city of Chicago, Illinois, and the federal government related to reducing reliance on fossil fuels and encouraging the adoption of cleaner, more efficient energy systems.
  3. **Competition from clean energy alternatives.** The growing shift toward efficient electric appliances, which threatens to reduce the demand for natural gas.

  Using Groundwork Data's Gas Delivery Cost Model, we conduct a modeling analysis to assess the likely future levels of revenue and customer payments needed to sustain PGL's operations under the assumption that a full-scope SMP is approved by the ICC. We also examine the impact of gas customer departures as households and businesses chose to switch to electric alternatives for space and water heating, air conditioning, and other functionalities such as cooking.
- **Critical assessment of PGL's strategy.** We critically assess PGL's assertion that reinstating the full SMP is the most viable and cost-effective solution for addressing safety, reliability, and emissions concerns. We also evaluate PGL and WEC Energy's claims that electrification is infeasible and alternative gases offer a viable building decarbonization path for Chicago.

- **Regulatory and financial challenges.** We examine PGL's evolving regulatory landscape, including recent decisions that have negatively impacted Peoples Gas and the ICC's commitment to re-evaluate the role of gas utilities in Illinois' energy future in light of the state's climate goals. Given this heightened regulatory scrutiny, we examine what the impact would be of reducing capital spending on the Peoples Gas system.

B. Main findings

The extensive modeling analysis conducted for this report investigates the total costs of resuming PGL's SMP at both full-funding and restricted levels (75% and 50% of full funding). We also evaluate the impact of gas customer departures on these scenarios. Our main findings are as follows:

1. **Unsustainable rate increases.** Restarting the SMP at full scale would necessitate historically unprecedented rate hikes, even assuming a stable gas customer base. By 2040, the average annual per-customer delivery charge would need to essentially double, increasing from $1,206 to $2,424. Year-over-year rate increases of roughly 7% would be required. This compares with a 4.7% rate of annual increase in actual per customer delivery costs for the recent 2015 to 2024 period.

2. **Impact of a shrinking customer base.** With a moderately declining gas customer base, average delivery costs per remaining customer rise significantly because cost recovery for PGL's escalating rate base must be spread over a shrinking pool of ratepayers. Under a full-scope SMP, customer attrition of 50% by 2050 results in annualized rate increases of 12%, 2.5 times the year-over-year increases from 2015 to 2024 (4.7%).[1] Such a level of escalation – resulting in a 185% increase in per customer delivery charges by 2040 to $3,437 – would raise serious concerns about long-term affordability and customer retention, both of which are critical to maintaining stable PGL revenue streams. In addition, these levels of rate increases would undoubtedly accelerate customer departure from the gas system.

3. **Limited potential for rate-increase moderation through reduced capital expenditures.** Lower SMP spending will moderate upward pressure on customer rates; however, this effect may be overwhelmed by the impact of a shrinking gas customer base. Even with reduced SMP spending, a declining customer base would still require annual delivery cost increases of 8% to 10%. This suggests that merely scaling back capital investments will not be sufficient to alleviate the financial pressures facing Peoples Gas should customer departures accelerate.

4. **Escalating cost recovery risks.** Continuing the capital expenditures required by a full-scope SMP would expose WEC Energy to significant cost recovery risks (15% of the parent company's asset base is currently attributable to Peoples Gas). Assuming that a full SMP resumes, PGL's unrecovered balances would surge by 127%, reaching approximately $12 billion by 2040. Complete cost recovery would not occur until after the year 2100. This sharp rise in stranded asset risk over the next 15 years increases the likelihood of significant financial write-downs, especially if regulators take steps to protect taxpayers from bearing the costs of decommissioning the gas network.

5. **Capital costs that significantly exceed previous annual spending levels.** Given the extensive work remaining, PGL and WEC Energy will need to spend much more annually on the SMP than they previously have or project to spend. To complete the SMP by 2040, annual capital spending would need to increase to $547 million beginning in 2025 compared to the historical annual average SMP spending level of $280 million.

6. **Heightened regulatory intervention.** Recent actions by the ICC, coupled with the sunsetting of the QIP Rider, have introduced new regulatory challenges for Peoples Gas that have begun to alter the company's investment risk profile. Peoples Gas has been adversely impacted by

1 By "rate increase" we refer to increases in average delivery costs per customer (or the increase in revenue requirement per customer not including charges for actual therms of gas consumed). Assuming the commodity price of gas remains stable, then these delivery cost increases are a reasonable approximation of increases in average customer gas rates.

these regulatory decisions, including a negative credit review from Moody's Ratings, a subsequent decline in WEC Energy's stock price, and capital spending disallowances. While the outcomes of two critical dockets are pending (the 2024 SMP Investigation and ICC's Future of Gas proceeding), it is clear that Peoples Gas must now operate in a regulatory environment predicated on heightened scrutiny, a focus on decarbonization, and concern about the rising costs of system modernization.

7 **Inadequate strategic response.** Peoples Gas and WEC Energy's current plans do not adequately address the looming threats to their gas utility business model and, therefore, do not adequately allow investors to assess the financial and operational risks associated with a shrinking customer base, escalating infrastructure costs, and regulatory pressures. PGL states that it has not conducted an analysis of Chicago's future energy consumption patterns. Such an analysis is essential and would ideally be coordinated with the city's electric utility, Commonwealth Edison, allowing for the modeling of reasonable scenarios for the uptake of efficient, non-gas technologies by the building sector. In addition, while PGL asserts that a critical role of the SMP is to carry alternative fuels, PGL has not provided feasibility and/or cost/benefit analyses related to decarbonizing the city's gas system by blending in RNG and/or hydrogen.

8 **Future infrastructure challenges.** The scope of system modernization planning put forward by Peoples Gas is confined to the next 15 years and excludes the substantial amounts of pipeline that will be in need of replacement after the SMP concludes. For example, by the 2050s, an additional 1,000 miles of distribution mains installed in the 1980s and 1990s will be queuing up for replacement. If the Peoples Gas system is to be continued indefinitely, then the Chicago gas territory needs a comprehensive, viable plan for the future of gas not just for the duration of the SMP but through the end of the century.

C. Investor risks and strategic implications

PGL's current trajectory raises significant strategic concerns for WEC Energy and its investors, given the financial and operational challenges outlined above. While Peoples Gas has historically delivered strong financial results, mounting risks threaten to negatively impact its financial performance. The long-term sustainability of PGL's operations in Chicago is in question, with potential repercussions that extend beyond Peoples Gas to the broader financial health and creditworthiness of the parent company, requiring investors to carefully assess how evolving regulatory, financial, and market risks might impact WEC Energy's future stability and profitability.

Regulatory risks

- **Sunsetting of the regulatory mechanism allowing for accelerated cost recovery.** Accelerated cost recovery played a pivotal role in sustaining PGL's earnings but it expired in December 2023. As a result, future cost recovery efforts will likely take place in more frequent and potentially contentious rate cases, introducing greater financial uncertainty for Peoples Gas. Longer lag times for cost recovery may negatively impact PGL's future cash flows.
- **Potential reductions in earnings.** Any curtailment of the SMP by the ICC, so as to limit rate increases or curb stranded asset risk, would reduce PGL's earnings. We estimate that a 50% reduction in a fully-funded SMP would result in a 33% decrease in the company's earnings before interest and taxes (EBIT) by 2040.
- **Frequent rate increases.** Chicago's gas delivery rates are already among the highest in the nation and substantial PGL rate hikes could exacerbate affordability issues, particularly for low-income and energy-burdened customers. The need for rate increases that significantly exceed historical trends is likely to lead to regulatory and possibly legislative intervention, developments that would present risks for investors.

- **Additional regulatory intervention.** With limited relief achievable through reduced capital expenditures alone, additional regulatory actions, such as more stringent prudency reviews, are more likely.

Market risks

- **Shrinking customer base.** As gas delivery costs rise and the competitiveness of electric alternatives improves, gas customer attrition is likely to accelerate. This could trigger a negative feedback loop where further departures increase the financial burden on remaining ratepayers and undermine cost recovery efforts. For Peoples Gas, a shrinking customer base will increase cash flow uncertainty and put downward pressure on profitability, potentially adversely affecting net present value.
- **Elevated cost recovery and stranded asset risk.** Continuation of a full-scope SMP could see unrecovered balances in PGL's rate base reach approximately $12 billion by 2040. Coupled with the potential for customer departures and uncertainty about the magnitude of PGL's obligations for retiring or decommissioning gas assets, Peoples Gas faces enhanced risk of not recovering the capital it has invested in the gas system.

Credit Risks

- **Potential credit downgrades.** Unstable rating outlooks for Peoples Gas have already begun. Actual credit downgrades are a serious possibility given the combined pressures of pending regulatory dockets and decisions, high gas system infrastructure costs, and declining gas demand. These would put pressure on WEC Energy's credit rating risk, likely increasing the parent company's cost of capital and eroding investor confidence.

Strategic misalignment with climate goals and policies

- **Conflict with climate policies.** PGL's strategy of expanding and modernizing fossil fuel infrastructure increasingly conflicts with the aggressive climate goals of the city of Chicago and Illinois. This misalignment exacerbates the risks of regulatory and market pressures as policies may increasingly prioritize the transition away from natural gas for Chicago's building sector.
- **Threat to "solvency" of low-income discount rate (LIDR) structure.** The state's signature climate law, CEJA, mandated the ICC to study how bill impacts for low-income utility customers could be mitigated and gave the ICC authority to file tariffs establishing LIDRs. In October 2024, Peoples Gas will begin implementing a LIDR that caps gas charges at 3% of household income, providing a credit to energy-burdened customers offset by a rider applied to other ratepayers. However, if gas rate increases accelerate due to SMP spending and/or customer departures, LIDR's cross-subsidization of rate classes could become strained, potentially rendering the structure unworkable if it further incentivizes customer departure and attracts financial and political attention.

D. Conclusion

Peoples Gas and WEC Energy stand at a critical juncture. The risks and uncertainties highlighted in this report underscore the growing challenges of sustaining the financial health and viability of traditional gas utility operations during the energy transition. As regulatory scrutiny intensifies, and as market dynamics evolve in response to shifting consumer preferences and technological advancements, the business model that has underpinned Peoples Gas for over a century is becoming increasingly vulnerable.

The situation that Peoples Gas faces is emblematic of pressures across the nation that mature, incumbent gas-only utilities may encounter as they grapple with rising infrastructure costs, regulatory changes, and competitive threats from disruptive technologies. Decisions made in the near future regarding the financial path of Peoples Gas will provide important lessons for other energy companies confronting similar risks.

For investors, the evolving challenges confronting Peoples Gas serve as a critical reminder of the complexities involved in the ongoing energy transition and the future of gas. It is essential to monitor these developments closely as they could have significant implications not just for WEC Energy but for the broader utility sector.

Public

THE WATCHDOGS NEWS POLITICS

Peoples Gas pipe replacement is costing Chicagoans more

A vast plan to replace deteriorating natural gas pipes and upgrade the system is not only costing you more, but it's also behind schedule.

By Stephanie Zimmermann | Feb 16, 2021, 8:42pm EDT

Peoples Gas workers installing a new natural gas pipe in Albany Park in 2019. The utility is replacing deteriorating gas pipes under a program that's scheduled to take until 2040 to complete. | Victor Hilitski / Sun-Times file

The average Peoples Gas customer in Chicago paid $131 last year on top of their monthly bills for the utility's massive pipe-replacement work, according to a report the utility filed Tuesday.

And that figure could hit $174 by the end of this year if it keeps rising at its current pace, a consumer group says.

The added cost amounted to about 11% of the typical customer's bill.

The Illinois Public Interest Research Group, a nonprofit advocacy group, says consumers are now paying about 10 times the original $1.14-per-month estimate given to the Illinois Legislature when it passed a law in 2013 allowing the utility to bill customers via an added "rider" on their bills for the work.

And the work is behind schedule. About 51 miles of deteriorating gas pipes were replaced last year, fewer than the planned 70 miles, according to the quarterly report Peoples Gas filed with the Illinois Commerce Commission.

The program has been plodding along for well over a decade. Originally pegged at $1.4 billion in 2007, it could end up costing $8 billion to $11 billion by the time the work is finished in 2040.

Peoples Gas said that, although its original cost estimate was too low, a more comprehensive program that it's undertaking now will result in better, safer service.

RELATED

Peoples Gas' plan to replace all pipes in Chicago could cost consumers much more

Illinois PIRG says that what began as a necessary project to replace aging gas lines for safety reasons has ballooned into a much larger and more expensive program that's also moving the entire natural gas system from low pressure to medium pressure.

The group says some of the neighborhoods at greatest risk from old, leaky pipes are having to wait years while the utility focuses on the overall system modernization.

And as the decades roll on, it says, improved technology might mean consumers won't be as dependent on natural gas by the time the work's done.

Peoples Gas — which serves Chicago — says the change to medium pressure will make the system much safer and includes automatic shutoff valves for each building that can detect and prevent problems such as the explosions and fires that hit about 40 homes in three towns near Boston in 2018. A low-pressure system failed during pipe work there, and one person was killed and many others were injured.

The utility says it tries to plan its pipe-replacement work to coincide with other utilities' projects, so streets don't need to be dug up twice.

"We still believe the way that we're doing it is a better deal for consumers," a spokeswoman said, adding that the utility has also increased its financial assistance programs over the past year.

Gov. J.B. Pritzker has called for an end to billing surcharges like the one allowing Peoples Gas to tack on the rider for the pipe work. And Mayor Lori Lightfoot and the Chicago City Council have called for stricter state oversight of the pipe replacements.

BUSINESS

Peoples Gas pipeline program will cost another $12.8 billion to complete, report says, socking Chicago customers with 7% annual rate increases through 2040

Juan De Luna, left, and Lino Banuelos, from Miller Pipeline, put the finishing touches on a section of a Peoples Gas pipeline replacement project at Wrightwood and

By **ROBERT CHANNICK** | rchannick@chicagotribune.com | Chicago Tribune
PUBLISHED: October 29, 2024 at 4:00 AM CDT

As the Illinois Commerce Commission nears a decision on the fate of the paused Peoples Gas pipeline replacement program following a yearlong review, a study released Tuesday for the Citizens Utility Board warns that completing the work would cost another $12.8 billion — topping recently revised utility projections by more than $5 billion.

Peoples Gas would need to impose record-breaking 7% annual rate increases over the next 15 years to cover that cost, effectively doubling delivery charges for its customers by 2040, the target completion date for the Safety (formerly System) Modernization Program, according to the Groundwork Data report commissioned by CUB.

“Our analysis finds that resuming the SMP at full funding levels puts Peoples Gas on an unsustainable trajectory with respect to revenue requirements and customer rate increases,” the report concluded.

Peoples Gas, which was provided a copy of the report before its release, refuted many of the findings — including the remaining cost — and disagreed with the conclusion that completing the pipeline replacement program was financially untenable for the company and its customers.

At the same time, the utility acknowledged that the projected price tag has gone up by billions of dollars since the program was paused by the ICC last fall.

“Unfortunately, the delay caused by the ICC’s decision to pause the safety work will likely have some cost impacts,” Peoples Gas spokesperson David Schwartz said in a statement.

Groundwork Data is a New York-based consulting firm focused on the transition to clean energy, a government-mandated change that the report said will reduce demand for natural gas before the pipeline project is completed, increasing the cost burden for remaining Peoples customers.

The ICC is expected to issue an order in January on the scope of the pipeline replacement program moving forward, but Tuesday’s report is too late to be filed as part of the proceedings, a CUB spokesperson said.

Launched in 2011, the program to replace 2,000 miles of aging iron pipes below Chicago streets was plagued from the outset by delays and budget overruns. More than a decade later, the project is 38% complete and Peoples Gas says it will take until 2040 to finish — if the ICC approves its resumption.

The pipeline replacement program was originally projected to cost $2.6 billion and take 20 years to complete. Those projections have been upwardly revised several times since Milwaukee-based WEC Energy Group acquired Peoples Gas in 2015.

Peoples Gas has spent $3.3 billion on the pipeline replacement program to date, Schwartz told the Tribune. The utility's 891,000 Chicago customers have borne that cost.

Last year, Peoples Gas asked for a record $402 million rate hike for 2024, in large part to continue funding the pipeline replacement program after a 10-year legislative surcharge enabling it to automatically pass the costs along to customers expired. The ICC reduced the rate increase and paused the program for the entirety of 2024 to conduct an investigation.

At the time the program was paused, Peoples said it would cost $8 billion to complete, including the $3.3 billion already spent. That was at the low end of an $8 billion to $11 billion range that Peoples had filed with the ICC under the new owners in 2015.

During the review process with the ICC, Peoples Gas revised its projections, pegging its preferred pathway forward at $7.2 billion in additional spending to complete the project. That would put the entire project cost at $10.5 billion over 30 years.

The utility also presented two alternative approaches during the review process, the most expensive of which would cost nearly $13 billion to finish the work.

"Our proposal to restart work — if approved by state regulators — would cost $5.5 billion less than what CUB's allies proposed, and would keep total costs within the estimate-range we provided to the ICC in 2015," Schwartz said in a statement.

The Groundwork study said it will take $12.8 billion to complete the work —

Jim Chilsen, a spokesperson for Citizens Utility Board, a nonprofit watchdog group, defended the methodology of the Groundwork study, while questioning the credibility of Peoples Gas — at least in regard to its pipeline replacement projections.

“Peoples Gas has dramatically underestimated the cost of this program from day one, and they’ve never been right on their projections,” Chilsen said. “Our analysis is based on sound economic principles and corroborated by history.”

The replacement program was driven by pressure from the administration of former President Barack Obama to hold utilities across the U.S. accountable for aging pipeline systems following a 2010 explosion in San Bruno, California, that killed eight people, injured 58 and destroyed 38 homes.

But consumer advocates have argued for years that gas pipelines may be obsolete by the time Peoples completes the systemwide infrastructure upgrade, as the shift to electrification and renewable energy sources such as wind and solar gain traction.

An administrative law judge is expected to issue a proposed order on Nov. 25, with the commission having the final say on whether and in what form Peoples can resume the pipeline replacement program.

While it is too late to introduce the CUB-commissioned report into the pipeline review process, the consumer advocacy group plans to present it as part of the ICC’s ongoing Future of Gas proceeding, a series of workshops studying issues tied to decarbonization of the state’s gas system.

CUB is also hoping it will play a role in the court of public opinion — before the ICC rules on the pipeline program in January.

“This is the first report to actually detail the financial disaster that could be in store for Peoples Gas customers if the utility isn’t held in check,” Chilsen said. “We look at this report as a warning that the Peoples Gas pipe replacement boondoggle will become an even bigger financial disaster for customers if regulators don’t intervene and rein in the company’s reckless spending.”

rchannick@chicagotribune.com

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

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PROOF OF SERVICE

On the date below, an electronic copy of the **Exhibits of Rick Brown, Dr. Melissa Stults, and Michael Walsh on behalf of the City of Ann Arbor** was served on the following:

Name/Party	E-mail Address
Michigan Office of Administrative Hearings and Rules Christopher S. Saunders, ALJ	 saundersc4@michigan.gov
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The statements above are true to the best of my knowledge, information and belief.

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CITY OF ANN ARBOR

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