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May 7, 2024

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

RE: MPSC Case No. U-21291

Dear Ms. Felice:

Attached please find the following document for e-filing:

- Direct Testimony and Exhibits of Asa S. Hopkins on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (MEC-1 through MEC-16);
- Proof of Service.

Sincerely,

Digitally signed by Christopher Bzdok
DN: cn=Christopher Bzdok, o=Troposphere Legal, email=chris@tropospherelegal.com, c=US
Date: 2024.05.07 11:15:46 -04'00'

Christopher Bzdok
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Cc: Parties to Case No. U-21291

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.	Case No. U-21291

DIRECT TESTIMONY OF DR. ASA S. HOPKINS

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES DEFENSE COUNCIL, AND SIERRA CLUB

May 7, 2024

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I. INTRODUCTION AND QUALIFICATIONS

Q1 Please state your name, business address, and position.

A1 My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139. I am a Vice President at Synapse Energy Economics, Inc. Among other work, I lead Synapse's consulting regarding the future of gas utilities, and I also work extensively in the related area of building decarbonization technology and policy.

Q2 Please describe Synapse Energy Economics.

A2 Synapse Energy Economics is a research and consulting firm specializing in energy industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, state policymakers, regulatory commissions, and environmental advocates.

Q3 Please describe your professional experience before beginning your current position at Synapse Energy Economics.

A3 Before joining Synapse Energy Economics in 2017, I was the Director of Energy Policy and Planning at the Vermont Public Service Department from 2011 to 2016. In that role, I was the director of regulated utility planning for the state's public advocate office, and the director of the state energy office. I served on the Board of Directors of the National Association of State Energy Officials. Prior to my work in Vermont, I was an AAAS Science and Technology Policy Fellow at the U.S. Department of Energy ("DOE"), where I worked in the Office of the Undersecretary for Science to develop the first DOE Quadrennial Technology

Review. Prior to my time at the U.S. DOE, I was a postdoctoral fellow at Lawrence Berkeley National Laboratory, working on appliance energy efficiency standards. I earned my PhD and Master's degrees in physics from the California Institute of Technology and my Bachelor of Science degree in physics from Haverford College. My resume is included as Exhibit MEC-1.

Q4 Have you previously provided evidence before the Michigan Public Service Commission ("the Commission")?

A4 No.

Q5 Have you previously provided testimony in other jurisdictions on topics similar to those you are testifying to in this case?

A5 Yes. I have testified on gas utility issues, as relates to capital decision-making, rates, and business risk in Connecticut, Quebec, Ontario, Maryland, Washington, DC, Wisconsin, and New York. When I testified before the Régie de l'Energie in Quebec I was recognized as an expert in "energy transition in the gas industry, and business risk." The Ontario Energy Board qualified me as an expert on "the future of electric and gas utility regulatory and business models and associated business risk in the context of deep building decarbonization objectives."

Q6 On whose behalf are you providing evidence in this case?

A6 I am testifying on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club.

Q7 What is the purpose of your testimony?

A7 The purpose of my testimony is to introduce the energy transition and evaluate several components of DTE Gas Company's ("DTE", "DTE Gas", or "the Company") rate proposal within that frame, notably the Company's underlying load forecast and its assumptions and accounting for new customer attachments and community expansions. I also address the need for a "future of heat" regulatory proceeding.

Q8 How is your testimony organized?

A8 My testimony begins with a summary of my conclusions and recommendations. Section III introduces the energy transition and puts this case in that context. Section IV addresses DTE's load forecast. Section V addresses individual customer attachments; Section VI addresses community expansions. Section VII concludes my testimony with a discussion of a future of heat regulatory proceeding.

Q9 Are you sponsoring any exhibits?

A9 Yes, I am sponsoring the following exhibits:

Exhibit MEC-1:	Resume of Asa Hopkins
Exhibit MEC-2:	ICF RNG Report
Exhibit MEC-3:	LETI. *Hydrogen: A decarbonisation route for heat in buildings?*
Exhibit MEC-4:	Liebreich Hydrogen Ladder
Exhibit MEC-5:	Net Zero America Data
Exhibit MEC-6:	Brattle Future of Gas
Exhibit MEC-7:	Comparison of Customer Economics
Exhibit MEC-8:	DPU Order 20-80

Exhibit MEC-9:	MNSCDG-6.1a
Exhibit MEC-10:	MNSCDG-2.10c
Exhibit MEC-11:	MNSCDG-5.11gi
Exhibit MEC-12:	MNSCDG-1.8h
Exhibit MEC-13:	MNSCDG-1.8fi
Exhibit MEC-14:	MNSCDG-1.8b
Exhibit MEC-15:	MNSCDG-1.9, -4.4bi, and -4.4ai
Exhibit MEC-16:	MNSCDG-4.6f Attachment, DTE Low Carbon Energy Infrastructure Enhancement and Development Grant Proposal

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q10 Please summarize your primary conclusions.

A10 I find that:

- Michigan has committed to achieve net-zero emissions by 2050. The resulting energy transition will lead to substantial decreases in the volume of gas transported through DTE's distribution system, which will result in changes to DTE's rates and competitive position.
- The energy transition is relevant for decision-making about planning and investment in the Company's capital system, how the Company accounts for system expansions to serve new customers, how the Company makes decisions about repair or replacement of its assets and considers their future usefulness, and how the Company depreciates its assets.
- DTE has not adjusted its load forecast and customer count forecast methodology or its analysis of customer attachments and community expansion to account for the energy transition.
- DTE's gas demand forecast does not fully reflect potential future changes in gas demand and therefore is likely to be too high. This is mainly because DTE's load forecasting methodology heavily relies on historical trends and

does not recognize any climate policy impacts that are likely to arise over the next decade.

- It is not reasonable for DTE to assume that new customers will use a constant amount of gas over 20 years when calculating those customers' expected contributions in aid of construction.
- DTE consistently overestimates the number of customers that will connect to community expansion projects. This results in under-collection of contributions in aid of construction relative to expectations, and it shifts costs for community expansion projects to non-participating customers.
- Based on historical rates of customer attachments, the Mesick-Buckley expansion will have a deficit of about $838,000 and the Peach Ridge expansion will have a deficit of about $912,000. DTE's past overestimates likely have an aggregate under-recovery of between $6 million and $11 million. It is not just and reasonable to ask DTE's non-participating customers to pay these costs.
- To correct these deficits, the monthly customer charges in expansion areas would need to rise substantially. At these higher customer charge levels, electric heat pump equipment would have lower operating costs than gas.
- DTE's aggregate overrun for the construction cost of 15 recent community expansion costs is about $9.75 million, or about 16 to 17 percent.

Q11 Please summarize your primary recommendations.

A11 I recommend that the Commission:

- Require DTE to develop a policy-consistent load forecast and evaluate the need for and prudence of its investments in light of that forecast;
- Require DTE to amend its tariffs to use a 10-year period for calculating the revenue deficiency;

- Order DTE to use customer adoption rates based on historical experience when calculating new attachment surcharges, and shift to using a 10-year period of stable consumption when setting the surcharge;
- In the event that DTE cannot or will not adjust the customer charges for Mesick-Buckley and Peach Ridge to align with the corrected levels, disallow $838,000 from the revenue requirement for Mesick-Buckley and $912,000 for Peach Ridge;
- Order that cost overruns for expansion projects will face a rebuttable presumption of imprudence and disallowance; and
- Initiate a "Future of Heat" proceeding that would bring all essential utilities and stakeholders together to address the energy transition in building and industrial heat.

III. INTRODUCTION TO THE ENERGY TRANSITION

Q12 Could you please describe what you mean by the term "energy transition"?

A12 By "energy transition" I mean the transition away from fossil fuel energy sources and toward renewable and zero-carbon energy sources as part of an economy-wide transition to reduce greenhouse gas (GHG) emissions by 80 percent or more by 2050. This transition is the instantiation of many state- and nation-level commitments to achieve net-zero emissions, including Michigan's, which I discuss in further detail below.

Q13 What are the primary pathways seen for the energy transition in the building and industrial sectors?

A13 Today, the building and industrial sectors consume electricity for a wide range of end uses and directly combust fuels for space, water, and process heating (as well as cooking, laundry, and other incidental uses). Electricity decarbonization is a relatively straightforward process and already underway, spurred by falling costs of renewable generation technologies such as solar and wind, and accompanied by advances and falling costs in battery and other energy storage technology. Decarbonization of heating, on the other hand, requires either substitution of fossil fuels with limited and/or expensive supplies of lower-carbon combustion fuels, or electrification (such as with highly efficient heat pump technologies). Electrification reduces emissions by taking advantage of the known pathways to decarbonized electricity to supply these end uses.

Q14 Why does electrification rise to the top of the options for building sector decarbonization, rather than low-carbon fuels?

A14 Low-carbon fuels such as renewable natural gas (RNG), hydrogen, and synthetic methane face a set of challenges that impede their ability to provide a decarbonization solution at scale while competing with electrification. These challenges are: (1) limited supply of biological feedstocks; (2) non-zero net GHG emissions; and (3) high cost. Each fuel option faces a different blend of these challenges.

RNG is generated from biological wastes (such as from landfills, food, forestry, or animal wastes). There is a limited quantity of such wastes, sources are not connected to the gas system, and that quantity is substantially lower than the total amount of fossil gas that needs to be displaced or replaced. For example, a recent ICF study conducted for the Commission states that "ICF's estimates for renewable natural gas deployment in Michigan for the Achievable and Feasible scenarios amount to 8.5% and 22.0% of the average annual natural gas consumption in relevant sectors for the last five years for which there are data available."[1] In addition, RNG made from these biological sources generally has net-positive GHG emissions; the only common exception is RNG from animal wastes. Animal wastes are a limited subset of feedstocks for RNG.

Green hydrogen (made from splitting water) could be created at a larger scale, provided sufficient electric power is available. Here the primary supply-side challenge is that hydrogen is competing with other uses for electric power that can more efficiently provide many of the same energy services. Producing hydrogen from electricity and then combusting that hydrogen to provide heat is much less efficient than using electricity directly through heat pumps; multiple times more electricity is required via the hydrogen pathway.[2] In addition, hydrogen has severe limits when using existing distribution system infrastructure. Hydrogen embrittles steel, so it either has to use a blend level below 7 percent (on an energy or emissions basis, and therefore with only a small impact on emissions) or requires full-system conversion to hydrogen-safe materials (which may also need to be resized to deliver sufficient energy using a lower-density gas). This retrofitting would include all equipment in customer homes. Hydrogen may be suitable for a small number of

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[1] ICF. September 23, 2022. *Michigan Renewable Natural Gas Study: Final Report*. Prepared for the Michigan Public Service Commission. Accessed at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/RenewableNaturalGas/MI-RNG-Study-Final-Report-9-23-22.pdf. Attached as Exhibit MEC-2.

[2] LETI. *Hydrogen: A decarbonisation route for heat in buildings?*. Attached as Exhibit MEC-3.

hard-to-electrify end uses where it has fewer competitors,[3] but that is not sufficient scale to change the implications for gas utilities.

Synthetic methane, produced by combining green hydrogen with carbon captured from non-fossil sources, is even more costly and uncertain because it requires access to a pure source of non-fossil carbon in addition to overcoming almost all of the challenges of hydrogen.[4]

Q15 Why is the energy transition relevant for this case?

A15 Gas distribution utilities such as DTE Gas get their revenue by transporting fossil fuel gas to customers over an extensive pipeline network, and by recovering the cost of that transmission and distribution network over many years through delivery charges added to the cost of the gas commodity. Under the principles of utility regulation used in Michigan and across the country, utilities can recover and earn a return on prudent investment in their systems from their customers through rates if the assets are used and useful. The energy transition will require substantial reductions in the amount of gas delivered. For example, the Net Zero America study, conducted by researchers at Princeton University, identified that pipeline gas use in Michigan would fall by a factor of two or more by 2050 in all scenarios that achieve net-zero emissions; in high electrification cases Michigan pipeline gas use

[3] Liebreich, M. *Clean Hydrogen Ladder, Version 5.0*. Attached as Exhibit MEC-4.

[4] Synthetic methane does have the advantage relative to hydrogen that it can be used in existing equipment and transported using existing pipelines.

falls by more than a factor of seven.[5] Reductions like these will require changes in the Company's rates. This will change the competitive position of the Company's service compared with alternatives. In addition, some of the Company's assets may no longer be needed to provide service (that is, no longer used and useful) and would therefore need to be removed from the rate base. If these assets are not fully depreciated, this could create stranded costs borne by either utility investors or the Company's remaining customers. The energy transition is therefore relevant for decision-making about planning and investment in the Company's capital system, system expansions to serve new customers, decisions about repair or replacement of its assets and considers their future usefulness, and asset depreciation.

Q16 Is it generally accepted that there is a transition happening in the energy sector?

A16 Yes. The federal government has made formal international commitments to reduce nationwide GHG emissions by more than half from 2001 levels by 2030, and to put the country on a path to net-zero emissions by 2050. Numerous states have established targets through laws and executive orders. At both the federal and state levels, policymakers are taking actions to make those commitments a reality through regulations, incentives, codes and standards, and other policies and programs. U.S. GHG emissions fell by more than 15 percent from their peak in

[5] See Exhibit MEC-5 (from https://netzeroamerica.princeton.edu/?explorer=pathway&state=michigan&table=e-negative&limit=200).

2007 to 2021 and are below 1990 levels, a substantial impact resulting from climate policies.[6] Many states have seen emissions fall further.

Q17 Have policymakers studied the energy transition at the state and federal levels and implemented policies that will directly affect the economics of gas distribution utilities?

A17 Yes. Numerous states have conducted pathway analyses and energy plans that examine the energy transition. Notable comprehensive analyses include the New York Climate Scoping Plan, Massachusetts 2050 Roadmap and Clean Energy and Climate Plans (for 2025, 2030, and 2050), the Colorado GHG Pollution Reduction Roadmap, and the California Climate Change Scoping Plan. All of these state-level analyses identify electrification as a primary approach to decarbonizing the electric sector and project substantial reductions in pipeline gas use, and each of these states has initiated or enhanced policies and programs to encourage building electrification through incentives and utility obligations. These states have also all implemented regulatory processes to examine and reform how gas utilities conduct their business. New York has established a gas planning proceeding; Massachusetts regulators have completed Case No. 20-80 and laid out reformed approaches to gas utility planning; Colorado policymakers have established a requirement for Clean Heat Plans that will reduce emissions from customers of the natural gas system;

[6] U.S. Environmental Protection Agency (EPA). Accessed December 13, 2023. "Climate Change Indicators: U.S. Greenhouse Gas Emissions." Available at: https://www.epa.gov/climate-indicators/climate-change-indicators-us-greenhouse-gas-emissions.

and California policymakers have studied non-pipeline alternatives and initiated a Long Term Gas Planning Rulemaking.

Q18 What about in Michigan?

A18 Governor Whitmer has issued several executive orders that lay out a pathway to deep decarbonization. Through Executive Order 2019-12, Michigan joined the United States Climate Alliance, committing Michigan to reduce GHG emissions 26 to 28 percent below 2005 levels by 2025. In Executive Order 2020-10, Governor Whitmer directed the state to achieve economy-wide climate neutrality by 2050, and net-negative GHG emissions thereafter. The Governor further directed the creation of the Michigan Healthy Climate Plan, which was issued in April 2022. The Healthy Climate Plan includes a roadmap to 52 percent GHG reductions from 2005 baselines by 2030, including a 17 percent reduction in emissions related to heating Michigan buildings. The plan elaborates further with respect to natural gas: "To complement immediate policy actions, the Plan recommends the state undertake a pathway analysis to assess options to achieve carbon neutrality from natural gas production, transmission, distribution, compression, storage, and end uses in a least-cost manner. This analysis should consider a full range of options for decarbonizing natural gas end uses, including energy efficiency, electrification, fuel switching to renewable natural gas and hydrogen, and other potential opportunities."[7]

[7] Michigan Healthy Climate Plan, p. 43. https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf.

Michigan legislators have taken concrete action to change the policy landscape in line with the Healthy Climate Plan. The enacted Senate Bill 273 of 2023 explicitly allows electric utilities to offer efficiency electrification measures, encourages gas utilities to achieve most of their required energy waste reduction through building shell improvements that reduce heating demand (rather than through gas-burning equipment), and allows gas utilities to receive credit for waste reduction through electrification measures.

Q19 Could you please summarize the state of energy transition planning and strategies at the federal level?

A19 Federal climate planning occurs within the context of the United Nations Framework Convention on Climate Change and the Paris Agreement reached under the auspices of that multinational process. Under the Paris Agreement, countries pledge to take actions to meet nationally determined contributions (NDC) toward the worldwide emissions reductions required to keep temperatures at or below 2 degrees above pre-industrial levels. In 2016, as part of its initial NDC, the U.S. government presented the *United States Mid-Century Strategy for Deep Decarbonization*, a report that shows pathways and considerations for the United States to reduce GHG emissions by 80 percent or more below 2005 levels by 2050.[8] The report lays out two primary strategies for a low-carbon buildings sector: energy

[8] United States Executive Office of the President. 2016. "United States Midcentury Strategy for Deep Decarbonization." Washington, DC, p. 5. Available at: https://unfccc.int/files/focus/long-term_strategies/application/pdf/mid_century_strategy_report-final_red.pdf.

efficiency and electrification of end uses. In the residential and commercial sector, the plan involves a transition to electric space heating, hot water heating appliances, and high-efficiency heat pumps.

In 2021, the United States re-joined the Paris Agreement and set more ambitious reductions goals in its revised NDC: achieving net-zero emissions no later than 2050 and an interim goal of reducing net GHG emissions by 50–52 percent of 2005 levels by 2030. The government presented an updated *Long-Term Strategy* in 2021 in line with these updated goals and studied multiple pathways to achieve them.[9] All viable pathways emphasize decarbonizing electricity and electrifying end uses. For the building sector, the efficient use of electricity for heating, hot water, cooking, and other end uses is the primary driver for emissions reductions, moving away from natural gas and other fossil fuels. Specifically, the pathways assume that heat pumps and other electric heaters and electric cooking account for more than 60 percent of all sales by 2030 and almost 100 percent by 2050.[10]

The federal government will support rapid evolution in the energy sector and clean technology deployment through investment and incentives. The Long-Term Strategy identifies that the primary goals for the next decade are to increase efficiency measures and sales of electric appliances. In the longer term, the federal government has stated that all buildings need to be decarbonized through end-use

[9] United States Executive Office of the President. 2021. "The Long-Term Strategy of the United States," Washington, DC. Available at: https://unfccc.int/sites/default/files/resource/US_accessibleLTS2021.pdf.

[10] *Id*. at 32.

electrification and significant implementation of energy efficiency measures to lower overall demand and reduce energy waste. In the industrial sector, low- and medium-temperature heat processes are priority candidates for industrial electrification in the near term through increased use of industrial heat pumps, electric boilers, or electromagnetic heating processes. Energy demand overall is expected to decrease as efficiency improves, and the share of electricity in final energy demand will grow as end uses are electrified: from about 50 percent in 2020 to 90 percent or more by 2050 because the onsite combustion of gas, oil, and other fuels will decrease substantially.[11]

Q20 What policy and programmatic actions has the federal government taken that reflect the pathways and priorities identified in the Long-Term Strategy?

A20 The *Inflation Reduction Act* and *Infrastructure Investment and Jobs Act* (also known as the *Bipartisan Infrastructure Law*) together allocate tens of billions of dollars for energy efficiency implementation and deployment of low- and no-GHG emission technologies.[12] These laws are expected to drive large-scale adoption of technologies that will support electrification. The *Inflation Reduction Act* provides up to $2,000 of federal tax credits for air-source heat pumps and a 30 percent tax

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[11] *Id*. at 45.

[12] *See* Nadel, Steven. 2023. *How Utility Energy Efficiency Programs Can Use New Federal Funding*, American Council for an Energy-Efficient Economy (ACEEE). Available at: https://www.aceee.org/sites/default/files/pdfs/home_energy_upgrade_incentives_2-1-23_1.pdf; ACEEE. 2023. *Home Energy Upgrade Incentives*. Available at: https://www.aceee.org/sites/default/files/pdfs/how_utility_energy_efficiency_programs_can_use_new_federal_funding_-_encrypt_1.pdf.

credit for geothermal heat pumps.[13] The *Inflation Reduction Act's* Home Electrification Rebates Program provides substantial amounts of rebates, up to $8,000 for heat pumps and up to $1,750 for heat pump water heaters, to low- and moderate-income customers.[14] One study estimated that electric space heating would exceed the number of homes with gas space heating by 2032, even before factoring in the impact of the *Inflation Reduction Act*.[15] As these incentives make heat pumps more widely accessible, adoption rates will continue to accelerate.

The federal government has taken other substantial actions to accelerate electrification in the buildings sector and to shape and expand the market for heat pumps. President Biden invoked the *Defense Production Act* to speed up domestic production of heat pumps.[16] Under this program, the DOE will award up to $250 million to entities capable of establishing or expanding manufacturing capacity. Administrators for the Energy Star program, jointly run by the U.S. Environmental Protection Agency (EPA) and DOE, have proposed to update its programs for

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[13] Rewiring America. "25C Residential Energy Efficiency Tax Credit and 25D Residential Clean Energy Tax Credit." Available at: https://www.rewiringamerica.org/ira-fact-sheets.

[14] Nadel, Steven. 2023. *How Utility Energy Efficiency Programs Can Use New Federal Funding*. ACEEE. Available at: https://www.aceee.org/sites/default/files/pdfs/home_energy_upgrade_incentives_2-1-23_1.pdf.

[15] Mifsud, Ana Sophia and Rachel Golden. 2022. *Millions of US Homes Are Installing Heat Pumps. Will It Be Enough?* RMI. Available at: https://rmi.org/millions-of-us-homes-are-installing-heat-pumps-will-it-beenough/ (citing EIA Residential Energy Consumption Survey).

[16] U.S. Department of Energy. Last Accessed January 2, 2024. "Enhanced Use of Defense Production Act." Available at: https://www.energy.gov/mesc/enhanced-use-defense-production-act-1950.

heating systems to advance this policy direction. Specifically, the Energy Star program administrators have proposed to sunset Energy Star certification for furnaces and for cooling-only air conditioners, effective at the end of 2024 (with no new products certified as of December 30, 2023).[17] The program's proposal states that "With the passage of the *Inflation Reduction Act*, EPA sees an unprecedented opportunity for the ENERGY STAR program to support the national transition to the most energy efficient equipment available. The Agency recognizes an important responsibility to guide consumers to the choices that support the efficient electrification of residential space conditioning. As such, EPA is proposing to phase out the labeling and promotion of residential gas furnaces and [central air conditioners]."[18] The Energy Star statement also indicates that a similar approach would be taken for oil and gas boilers and dryers. As of this writing, Energy Star program administrators have not yet formally decided to make these program changes.

Q21 Do industry consultants see a changing world for gas utilities?

A21 Yes. For example, The Brattle Group developed an introductory set of materials as part of its marketing to gas utilities, called the "Future of Gas Utilities Series,"

[17] U.S. EPA (Climate Protection Partnerships Division) - ENERGY STAR. 2023. *HVAC Sunset Letter*. Available at: https://www.energystar.gov/sites/default/files/asset/document/HVAC%20Sunset%20Letter.pdf.

[18] *Ibid*.

presented as a series of webinars in the summer and fall of 2021. The first of these webinars lays out the context for risk assessment, and its materials[19] state that:

- "…cost declines related to innovation, as well as federal, state, and municipal support policy, will increase electrification"[20]
- "Utilities will need to consider how to recover their costs from a shrinking customer base, which could lead to higher rates and create a vicious cycle."[21]
- "Waiting Passively Is Not a Sustainable Option for Utilities or Customers. If gas utilities defer building a long-term strategy, they risk not having a voice in the policy, planning, and regulation process. Gas demand reduction and bill increases for remaining customers will come with or without utility involvement. However, the needed change is likely to be delayed or inefficient without utility involvement…. The transition process will play out over many years, but the planning must start now."[22]
- "The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032."[23]
- "As states pursue degasification policies and homes convert to electric heating, utilities risk losing customers and load. Nationally, electric heating is outpacing gas heating adoption. Technology mandates and policy further

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[19] The Brattle Group. August 2021. *The Future of Gas Utilities Series. Transitioning Gas Utilities to a Decarbonized Future Part 1 of 3*. Accessed at https://www.brattle.com/wp-content/uploads/2022/01/The-Future-of-Gas-Utilities-Series__Part-1.pdf and attached as Exhibit MEC-6.

[20] *Id.*, p. 2.

[21] *Id.*, p. 2.

[22] *Id.*, p. 4.

[23] *Id.*, p. 9.

> accelerate the problem. Utilities will likely continue investing in their existing system for safety and reliability but need to recover those costs from a shrinking customer base. This puts remaining customers at risk, a "death spiral" trend pushing more customers to electrification. Up to $150–180 billion of gas distribution assets could be under-recovered as a result of the transition. This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations."[24]

Q22 What do you see as the major implications of the energy transition for gas utilities?

A22 Utility commissions are increasingly recognizing that business-as-usual approaches to managing the gas system cannot continue. The major implications of the energy transition for gas utilities are:

- The future of gas consumption and gas utility asset utilization will not look like the past or present. Energy delivered by the gas system will fall substantially, and the building sector share of gas consumption will fall.
- To the extent that biomethane, hydrogen, or synthetic methane are used, they will be expensive enough that customers who can afford to electrify will do so instead of using those fuels via the gas system.
- Business-as-usual approaches to leak-prone pipe replacement are not justified. Capital investments should not be made until they are shown to be superior to alternatives that incorporate repair, efficiency, electrification, and retirement, accounting for the limited lifetime of pipe replacements.
- The recovery of invested capital over a smaller volume of sales will mean higher gas distribution rates and increased competition from electricity. The

[24] *Id.*, p. 11.

extent of these gas rate increases can be reduced by changes to the utility's approach to capital investment, repairs, retirement, and depreciation.

- Utilities have a responsibility to undertake prudent planning and investment actions to adapt to the energy transition, taking into account the timeframe of that transition and how it relates to the lifetime of gas assets. Failure to make prudent capital decisions increases stranded-asset risk, which may be borne by customers and/or investors.

Q23 What is the important take-away regarding the energy transition for this case?

A23 The future will not be like the present or past. Given long lives of utility assets, practices relating to those assets will need to change during their lifetime, even if near-term changes in sales are small. Gas infrastructure investment practices that assume continuity with the past are no longer reasonable or justified.

Q24 Has DTE adopted these lessons?

A24 No, it has not. As discussed in the remainder of my testimony, DTE has not adjusted its load forecast and customer count forecast methodology or its analysis of customer attachments and community expansion to account for the energy transition. The failure to do so is unreasonable and imprudent, and DTE should bear the costs and risks of its decisions in this regard.

IV. LOAD FORECAST

Q25 How does DTE develop load forecasts for its gas customers?

A25 DTE develops its load forecasts primarily based on the projected number of customers and average gas usage per customer (GHC-11, GHC-16). I will explain in detail how DTE develops projections of customer counts and average gas usage per customer below.

Projections of customer counts

DTE projects total customer counts based on DTE's projections of customer attachments (from new properties) and customer non-attachments (from the existing properties that are currently receiving gas services from DTE). Witness Chapel provides the projected average number of customers through 2028 in Exhibit A-15, Schedule E3. This projection shows a steady increase in customers over the next five years at annual growth rates of 0.7 percent for residential heating customers and 0.3 percent for commercial heating customers.

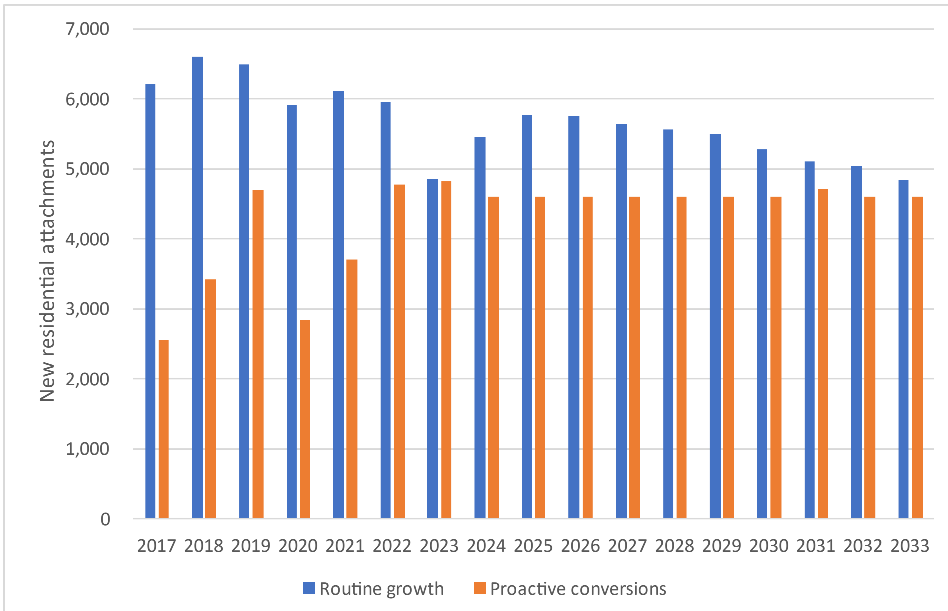
According to Witness Chapel, "[p]rojected attachments are provided by the Company's Marketing Department and is their assessment of how many new customers the Company expects to attach through marketing efforts in expanding areas."[25] DTE also states that "DTE uses historical attachment data and current market trends that identifies the cost differential between propane and natural gas to forecast attachments."[26] DTE develops its forecast of customer counts for two sub-groups: "Routine" growth (i.e., new construction customers) and "Proactive"

[25] Direct Testimony of George H. Chapel, GHC-6: 7-10.

[26] DTE's response to MNSCDG-2.7b.

conversions (i.e., line extensions and on-main conversions).[27] DTE's forecasts for these two types of customers are shown in Figure 1 below.

Figure 1. DTE's estimates of historical and forecasted residential customer attachments



Source: DTE Excel file *U-21291 MNSCDG-2.7a -Jun 2023 New Markets Attachments - 2023 Rate Case*, "Forecast Summary 2023" tab.

DTE provided its analysis of residential customer attachments in response to MNSCDG-6.1a. This analysis shows that, for the Routine category, DTE relies on Global Insight's forecast for new residential housing starts for the entire state to estimate the number of new houses with gas service within DTE's territory, assuming a factor of 78 percent for "Michigan State Nat Gas Penetration" and a factor of approximately 32 percent for "DTE Gas Service Territory Customer

[27] DTE's response to MNSCDG-9.1c.

Share" through 2033.[28] The share of DTE gas service customers in the state is based on the data for 2013 (per the "Assumptions - New Way" tab). In addition, the 78 percent factor for the share of gas heating customers out of all heating customers in the state is based primarily on a *Detroit News* article from October 26, 2012.[29] DTE states that it uses these historical data as a baseline and adjusts the data "if the previous year's actual results produced a +/- 10% difference to the respective forecast."[30] DTE's analysis indicates that it did not make any adjustments to the historical data mentioned above, which implies that the difference between actual results and forecasts were within the +/- 10% range.[31]

For Proactive conversions, DTE develops separate forecasts as shown in Figure 1 above. DTE develops these forecasts based on "historical attachment data and current market trends that identifies[*sic*] the cost differential between propane and natural gas."[32]

DTE employs a different approach for non-attachment customers. DTE forecasts non-attachment customers based on the changes in customer counts in recent historical years (1 to 3 years) in seven different demand regions.[33] In one place,

[28] An Excel file "U-21291 MNSCDG-2.7a -Jun 2023 New Markets Attachments - 2023 Rate Case," the "Forecast Summary 2023" tab and the "Assumptions - New Way" tab.

[29] Ex MEC-9, DTE's response to MNSCDG-6.1a.

[30] DTE's response to MNSCDG-9.1a.

[31] An Excel file "U-21291 MNSCDG-2.7a -Jun 2023 New Markets Attachments - 2023 Rate Case," the "Forecast Summary 2023" tab.

[32] DTE's response to MNSCDG-2.7b. Also see DTE's response to MNSCDG-10.11b.

[33] Chapel Direct, GHC-5 to 6; DTE's response to MNSCDG-2.8b.

Witness Chapel mentions "a recent three-year historical average growth/loss rate calculated for each of DTE Gas's seven demand regions"[34] for estimating customer counts and in another place he mentions "the 12-month historical look-back of net non-attachment customer change to the growth/loss rate."[35] While Witness Chapel is not clear exactly how DTE used these two methods (e.g., which methods it used for each region), what is clear is that DTE is using recent historical data to project growth in non-attachment customers and assumes no impacts from future policy changes.

Projections of usage per customer

On average, DTE's sales per customer have declined about 30 percent over the 26-year period from 1997 to 2022.[36] DTE projects continuing declines in gas usage per customer. Witness Chapel explains that DTE forecasts changes in overall gas usage per customer based on various factors including changes in the volumetric energy content of the gas DTE provides (the "heating value"), demographic changes in DTE's customer base, DTE's Energy Waste Reduction (EWR) program, and customer behavior in response to weather.[37] Among these factors, it appears that the EWR program has the largest impact. Witness Chapel states that DTE

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[34] Chapel Direct, GHC-5: 24-25; GHC-6: 1.

[35] Chapel Direct, GHC-6: 6-7.

[36] U.S. Energy Information Administration. Natural Gas Annual Respondent Query System. See https://www.eia.gov/naturalgas/ngqs/#?report=RPC&year1=1997&year2=2022&company=Name&items=1010CT,1010VL,101TVL,1110CT,1110VL.

[37] GHC-11, line 5 to 10.

"projected annual demand reductions due to EWR to be 1.05% for 2023, dropping down to 1.00% in 2024 and beyond" for residential customers.[38] This annual savings rate closely corresponds to the per-customer usage reductions that I observe from Exhibit A-15, Schedule E2, page 1 and 2, which shows projected gas volumes and average number of customers.

Q26 Does that forecast reflect what we know about the future demand for gas?

A26 No. DTE's gas demand forecast does not fully reflect potential future changes in gas demand and therefore is likely to be too high. This is mainly because DTE's load forecasting methodology heavily relies on historical trends and does not recognize any climate policy impacts that are likely to arise over the next decade (except small impacts from the continuation of the existing EWR programs). For example, as shown in Figure 1 above, DTE is forecasting almost the same number of Proactive conversions (i.e., line extensions and on-main conversions) per year for the next decade through 2033. Recall that DTE also assumes that the share of gas for space heating in new construction relative to other fuels and electricity stays the same (78 percent) over the next decade. DTE's load forecasting approach is inadequate for forecasting future gas demand because the future demand for gas will not be like the present or past, as I discussed earlier in this testimony.

[38] Chapel Direct, GHC-16: 18-19.

Q27 Are there any other aspects of DTE's load forecasting methodology that are not appropriate for forecasting future gas consumption or customers?

A27 Yes. DTE develops forecasts of Proactive conversions based on "historical attachment data and current market trends that identifies[*sic*] the cost differential between propane and natural gas."[39] This approach is inadequate to fully capture the current market trend, because adoption of electric heating has been increasing considerably over the past several years. According to the U.S. Census Bureau's American Community Survey, the number of Michigan households with electric space heating increased by 53 percent in 2022 relative to 2013, while the increase in utility gas heating households was only about 3 percent and the increase in propane was about 16 percent during the same period, as shown in Figure 2.[40] On the other hand, the number of households with wood space heating or fuel oil space heating declined substantially (falling by 35 percent to 45 percent, respectively). This clearly shows that DTE's approach that evaluates the choice as being only between utility gas and propane misses the biggest trend in the space heating market: toward electrification.

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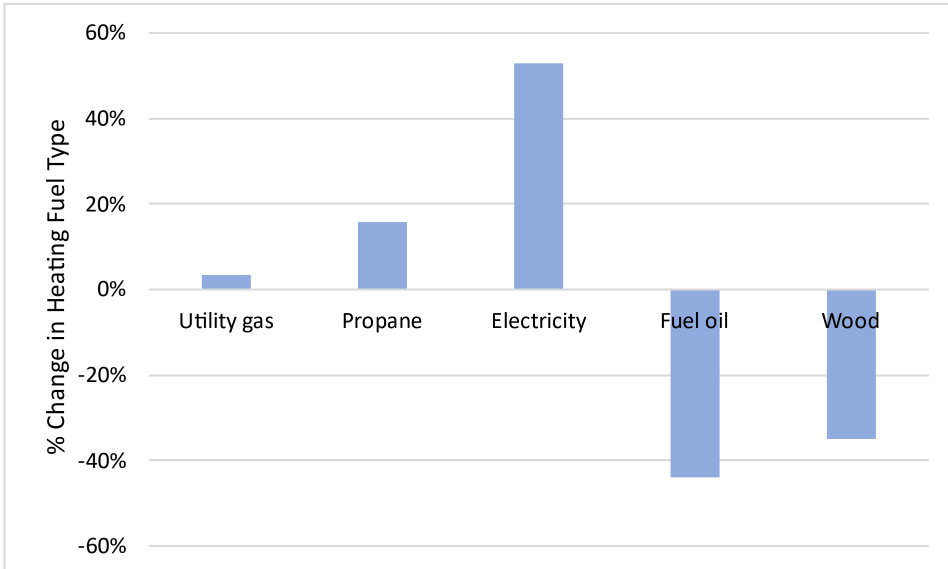
[39] DTE's response to MNSCDG-2.7b.

[40] U.S. Census Bureau's American Community Survey 1-Year estimate for 2013. https://data.census.gov/table/ACSDP1Y2013.DP04?g=040XX00US26; U.S. Census Bureau's American Community Survey 1-Year estimate for 2022. https://data.census.gov/table/ACSDP1Y2022.DP04?g=040XX00US26.

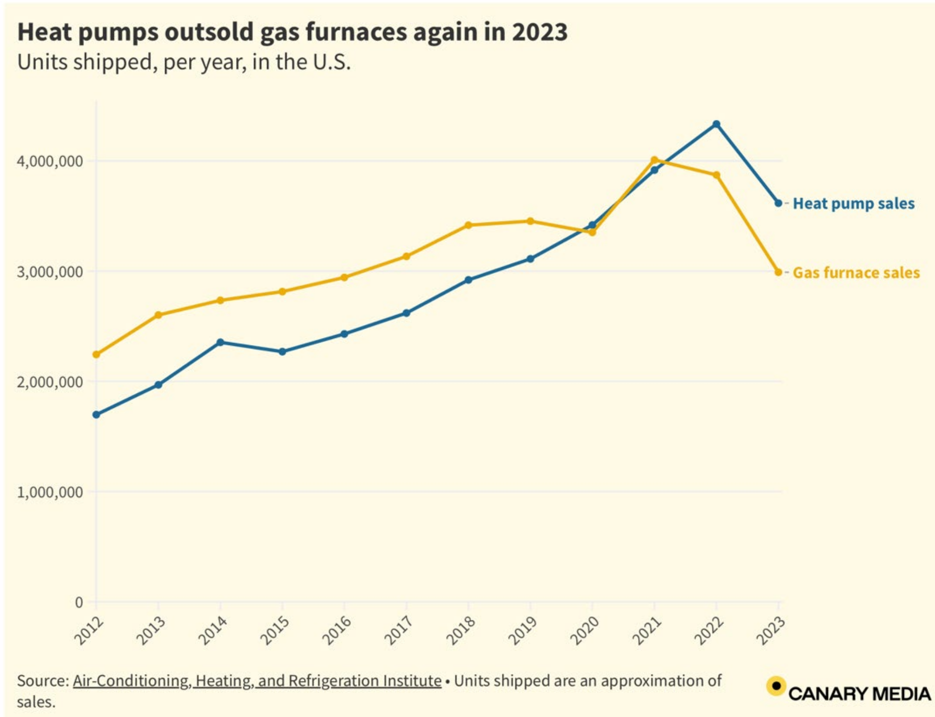
Figure 2. Changes in Michigan heating fuel type, 2022 relative to 2013



Source: U.S. Census Bureau. American Community Survey 1-Year estimates for 2013 and 2022.

Heat pump and gas furnace sales at the national level show a similar trend. As shown in Figure 3, the relative gap in equipment sales has been narrowing over the past decade between heat pumps and gas furnaces; heat pump sales surpassed gas furnace sales in 2022 and 2023.

Figure 3. National trend in heat pump and gas furnace sales



Source: Takemura, A. 2024. "Heat pumps outsold gas furnaces again last year — and the gap is growing." *Canary Media*. February 13. Available at: https://www.canarymedia.com/articles/heat-pumps/heat-pumps-outsold-gas-furnaces-again-last-year-and-the-gap-is-growing.

Lastly, this recent historical trend in heat pump and gas heating adoption rates is not consistent with the way DTE is forecasting the number of gas customers for new construction (or routine growth), where it is assuming a fixed share of 78 percent gas customers among all residential new construction projects.

Q28 Does DTE take state policy encouraging electrification into account in its load forecasting?

A28 In MNSCDG-2.8d, Witness Chapel states that "DTE Gas Company does not incorporate the impacts of the state's climate and clean energy laws into its customer count forecast. DTE Gas Company does not take a position about the impact of Senate Bill 273 on gas customer counts or attachments for its customer count forecast." Witness Chapel further states that "DTE Gas Company did not incorporate in its sales forecasts the impacts of the state's climate and clean energy laws, including Senate Bill 273."[41] DTE's Gas Delivery Plan includes a projection of future bills through 2033.[42] When asked if DTE takes account of electrification when making this projection, Witness Fedele stated that "[c]urrently, given the current legislation and costs, we don't believe electrification will have a significant impact on natural gas consumption in the next ten years. If it becomes significant in the future, our current methodology would be adapted to include the impact."[43] This assessment in inconsistent with both state decarbonization policies that require emissions reduction within the next 10 years and already existing trends towards residential electrification.

Q29 What are the implications of a load forecast that is too high?

A29 A load forecast with high gas consumption is likely to lead to overbuilding of gas pipeline systems. Such a forecast would also prevent DTE from considering retirements of gas pipelines in some segments of its service territory where a majority of customers may leave the system (e.g., switch to electric heating) to choose cleaner heating options that are supported by state and federal policies. Overbuilding of gas pipeline systems driven by DTE's flawed load forecast could result in overly expensive gas system costs and overly high gas bills for consumers.

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[41] Ex MEC-10, discovery response MNSCDG-2.10c.

[42] Exhibit A-12 Schedule B5.6, p. 9, Figure 5.

[43] Ex MEC-11, discovery response MNSCDG-5.11gi.

Q30 What should DTE do to improve its load forecast?

A30 As I mentioned above, I expect to see significant policy and programmatic actions at the state and federal levels that influence gas consumption in Michigan. DTE should develop a load forecast that accounts for such policy and programmatic actions and changing market conditions. More specifically, I recommend that the Commission require DTE to develop a forecast of future sales that reflects policy and market developments. For example, the Healthy Climate Plan lays out a roadmap to 52 percent GHG reductions from 2005 baselines by 2030, including a 17 percent reduction in emissions related to heating Michigan buildings. The Commission should require DTE to incorporate this 17 percent reduction in emissions from space heating end uses when it develops a policy-consistent sales forecast. For a business-as-usual case, I recommend that DTE develop its forecasts of gas customer counts and gas usage based on updated market conditions, including the latest data on the share of heat pump and gas furnace sales and installations. DTE should also examine the impacts of the declining share of gas customers, driven by various policies, on its forecast of gas demand. The Commission should also order DTE to make all underlying data, models, and assumptions for its forecast publicly available so that stakeholders and Commission staff can review the Company's methods.

Further, DTE should be required to evaluate all capital expenditures and supply contracts against both its business-as-usual forecast and a policy-consistent forecast.

Q31 What are the implications of a change in load forecast for rate cases such as this one?

A31 DTE is proposing extensive investments in its system, justified in part by the continued need to meet customer demands over the foreseeable future. DTE should ensure that each of its investments remains a prudent use of ratepayer funds under the corrected load forecast, and it should remove or change any investments that are not needed in this case.

V. INDIVIDUAL CUSTOMER ATTACHMENTS

Q32 Could you please summarize how DTE determines how customer contributions in aid of construction are calculated?

A32 DTE lays out its cost and revenue estimation and allocation approach in Section C8 of its Rate Book. As a high-level summary: DTE estimates the cost of constructing and maintaining the assets required to serve the new customer(s). It then estimates the incremental revenues associated with the new customers (not including the commodity cost of fuel), assuming constant per-customer gas consumption, and calculates the revenue deficiency. The revenue deficiency is the difference between the 20-year present value of the costs and the 20-year present value of the revenues. DTE requires that new customers pay for the revenue deficiency, either up front or over time. Note that this payment does not cover the full capital cost of the expansion: costs more than 20 years after installation are not reflected in the calculation. DTE applies the same general approach to both individual and community expansions, although community expansions have uncertainty regarding which customers will connect.

Q33 Over what time period does DTE conduct this calculation?

A33 Twenty years. That means that, if DTE's assumptions about the number of customers and their consumption are correct, there are no incremental revenues available from the new assets over 20 years to contribute to the cost of the rest of the gas system. Only after 20 years do revenues from new customers contribute to costs associated with the rest of the utility's system—the upstream portions of which will have been serving these customers throughout those 20 years.

Q34 What happens if the consumption or number of customers are lower than expected over that 20-year period?

A34 In that case, new customers do not pay for the costs of the assets that serve them, and DTE's other customers cover the difference, essentially subsidizing system growth. Put differently, on a present value basis, customers served by the new assets in this example do not contribute to other utility system costs for more than 20 years.

Q35 What happens if the consumption or number of customers is so low that the asset is retired before the new customers contribute enough to cover the revenue deficiency?

A35 In that case, DTE's other ratepayers protect DTE from a stranded cost. If the new assets were a standalone business, without subsidy from other customers, that business would have gone bankrupt: its total revenues would not have covered its total costs. Because of the nature of the regulated utility model, which shares system costs, however, the utility's other customers protect the utility's investors from experiencing that loss by paying higher bills.

Q36 Is it likely that sales from new customer additions will fall over 20 years?

A36 Yes. On average, DTE's sales per customer have declined about 30 percent over the 26-year period from 1997 to 2022. More competitive electric alternatives, based on heat pump technology, have become more widely available and adopted within the last decade, so electrification will join energy efficiency as a driver of future declines. While each community expansion samples only a subset of DTE customers, this general trend should apply to the subset. In addition, 20 years from now is 2044, just six years shy of the 2050 deadline for Michigan to achieve its goal of carbon neutrality (and the country's commitment to net-zero emissions). To meet these emission objectives, Michigan's use of natural gas will need to decline substantially—accelerating the declines seen over the last generation. One major driver of this decline will be electrification of space- and water-heating equipment. As buildings served by new mains and service lines electrify some or all of their equipment, their gas use will decline. The market segment of customers who electrify completely will also stop contributing their monthly customer charges to the revenue required to pay for the new gas assets.

Q37 Is it reasonable for DTE to set rates based on the assumption that gas use will remain constant over 20 years for all new customer attachments?

A37 No, it is not reasonable. Ignoring these market and policy trends will result in DTE's failure to meet the revenue deficiency, thereby pushing out for more than 20 years any customer contributions to the broader system's cost of service, beyond the cost of the assets serving their own building.

Q38 What do you recommend the Commission do to address this situation?

A38 I recommend that the Commission require DTE amend its tariffs and associated calculations to set a final date of 2034 beyond which DTE will not provide any cost support for new customer attachments. In conducting its revenue deficiency calculations, DTE would consider the present value of the net cost of the new assets only through 2034. DTE would also require customers to pay the net cost of the connection either up front or over a period that ends in or before 2034. By reducing the assumed payoff period for assets built for new customers, DTE can increase the likelihood that new customers will in fact pay off the revenue deficiency before decarbonizing, accelerate the timeframe in which new customers contribute to shared utility system costs, and reduce the likelihood of stranded costs.

Q39 Why is 2034 a reasonable date to end socialized support for new customer connections?

A39 Ten years is a reasonable period from today because it gives time for the utility and customers to gradually transition. This timeframe is comparable to the lifetime of gas-consuming equipment (e.g., about half the life of a typical gas heating system; comparable to the life of a water heater), so is an appropriate timeframe over which to transition to a new approach. By gradually removing subsidies year by year, this change should avoid market shocks while transitioning to a future in which existing customers are not subsidizing new customers to construct potential future stranded assets.

Q40 Have other jurisdictions revisited new customer contributions recently?

A40 Yes. I am aware of three regulatory commissions that have set a path to reduce or eliminate utility contributions toward the cost of new customer additions. That is, in these jurisdictions new customers will be directly responsible for more or all costs of the assets built to serve them.

Q41 What are the three jurisdictions you have in mind?

A41 I am thinking of Oregon, Ontario, and California.

Q42 Please describe the Oregon example.

A42 There are two examples in Oregon, related to NW Natural and to Avista.

- NW Natural offers a "line extension allowance" (LEA) for new customers. The amount of the LEA has been fixed at levels corresponding to the type of gas equipment to be installed, so that customers who will use more gas get a larger allowance. This reflects a similar economic argument as that which underlies DTE's calculation. In NW Natural's 2022 rate case, the Public Utility Commission of Oregon (PUC-O) considered evidence regarding reductions to the LEA.[44] The PUC-O concluded that the current level of the LEA was "problematic" for three reasons: it did not account for GHG emission compliance-related costs caused by customer expansion; that it was "too generous and saddl[ed] existing customers with increased costs for a period of time that is unreasonably long,"[45] and that "the current methodology, which assumes customers remain on the system for 30 years

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[44] Public Utility Commission of Oregon (PUC-O). *Order No. 22-388*. In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision (UG435). October 24, 2022. Pp. 31-54. Available at https://apps.puc.state.or.us/orders/2022ords/22-388.pdf.

[45] *Id.*, p. 49.

with a predictable throughput, is likely too optimistic of an assumption given the changes in the industry that are identified by the parties."[46] The PUC-O decided to reduce the LEA in each subsequent year, and to leave open the option to revisit the level of the LEA in a later proceeding.

- Avista agreed, as part of a stipulation settling its rate case in 2023, to phase down its line extension allowance: $2,500 in 2024, $1,250 in 2025, $750 in 2026, and $0 in 2027.[47]

Q43 Please describe the Ontario example.

A43 Enbridge Gas, North America's largest gas distribution utility, uses a similar revenue-deficiency-based calculation to determine customer contributions as does DTE. In its order in Enbridge Gas's recent rate case, the Ontario Energy Board (OEB) considered a wide range of arguments regarding the appropriate timeframe over which to conduct the economic analysis for contributions, considering energy transition risk.[48] The utility proposed to maintain the timeframe at 40 years, while other parties suggested values as low as zero years. The OEB ordered a reduction to zero years beginning January 1, 2025, in order to eliminate stranded cost risk.

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[46] *Ibid*.

[47] PUC-O. *Order No. 23-384*. In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision (UG461). October 26, 2023. P. 9. Available at https://apps.puc.state.or.us/orders/2023ords/23-384.pdf.

[48] Ontario Energy Board (OEB). *Decision and Order. Enbridge Gas Inc. Application for 2024 Rates – Phase 1*. EB-2022-0200. December 21, 2023. Pp. 23-45. Available at https://www.oeb.ca/applications/applications-oeb/current-major-applications/eb-2022-0200.

Q44 Please describe the California example.

A44 The California Public Utilities Commission (CPUC) eliminated all subsidies for gas line extension in September 2022, through a rulemaking process, effective July 1, 2023. This rulemaking process was "designed to be inclusive of any alternatives that could lead to the reduction of greenhouse gas emissions associated with energy use in buildings [related]… to the State's goals of reducing economy-wide GHG emissions 40% below 1990 levels by 2030 and achieving carbon neutrality by 2045 or sooner."[49] The CPUC eliminated line extension allowances, a 10-year refundable payment option, and a discount payment option.[50] In December 2023, the CPUC went further by eliminating *electric* line extension allowances for new construction buildings that use natural gas and/or propane.[51] As a result of this order, there are no subsidies from California's regulated utilities to new buildings that burn gas.

[49] California Public Utilities Commission (CPUC). Order Instituting Rulemaking (OIR) 19-01-011. P. 2.

[50] CPUC. September 20, 2022. *Phase III Decision Eliminating Gas Line Extension Allowances, Ten-Year Refundable Payment Option, and Fifty Percent Discount Payment Option under Gas Line Extension Rules.* Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K987/496987290.PDF.

[51] CPUC. December 14, 2023. "CPUC Eliminates Last Remaining Utility Subsidies for New Construction of Buildings Using Natural Gas." Accessed at https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-eliminates-last-remaining-utility-subsidies-for-new-construction-of-buildings-using-gas-2023.

VI. COMMUNITY EXPANSION

Q45 Could you please summarize DTE's community expansion program?

A45 DTE considers expanding its mains to serve new areas under the auspices of its customer attachment program. For each potential expansion, DTE conducts a calculation that balances the cost of the expansion with the increased revenue (referred to as the "spread") that the expansion would bring in, both over a 20-year period. To the extent that the revenue does not balance the costs over that 20-year period (on a present value basis), DTE calculates the gap (or revenue deficiency). DTE then uses the gap and the estimated number of new customers to calculate the additional monthly charge that will be placed for 10 years on the bills of all customers served by the expansion. This charge is set at the level where the present value of this revenue exactly offsets the deficiency that would otherwise exist between costs and revenues. DTE conducts the necessary calculations in a spreadsheet titled "Discounted Cost of Service Model Capm," which produces a New Customer Attachments Form.

Q46 What are the key parameters and assumptions for the economic evaluation of the gap between costs and revenues?

A46 Most of the parameters for community expansion are shared with the parameters for individual customer attachments (such as the weighted average cost of capital, tax rates, and depreciation rates). When evaluating the costs and revenues for a community expansion project, DTE assumes that:

- Per-customer consumption will be constant over 20 years (which is the same as in the individual customer case); and

- Fixed fractions of the potential customer base will connect each year, generally starting around 60 to 65 percent in the first year and rising by 5 to 10 percent per year through the next four years.

DTE's calculation tool allows for assumptions regarding growth, seasonal customers, and the costs of components (i.e., mains, services, and meters).

Q47 What is the Mesick-Buckley CAP?

A47 The Mesick-Buckley CAP is a project whereby DTE would build a main connecting the City of Manton to the villages of Mesick and Buckley, and serving new customers along the route. DTE estimates the overall project cost to be $14 million. DTE applied for and was awarded a grant of $7.3 million from the state's Low Carbon Energy Infrastructure Enhancement and Development Grant program. This reduces the net upfront cost to ratepayers to $6.8 million.

Q48 How many customers does DTE project the Mesick-Buckley CAP will serve?

A48 DTE projects that this project will serve 1,063 customers who are located adjacent to the project today, and 192 additional customers sourced from "miscellaneous" growth (e.g., new construction in the area) over the next 10 years.

Q49 What is the present value of the difference between the cost of the Mesick-Buckley CAP and the additional revenues that it would enable?

A49 DTE calculates a deficit of $2.16 million (after including the impact of the $7.3 million state grant).

Q50 What would each of these new customers pay as an additional monthly charge?

A50 Each new residential customer would pay an additional $27.76 per month, or $333.12 per year, for the first 10 years after the project is commissioned. Commercial customers would pay an upfront cost of $2,212 (regardless of building size).[52]

Q51 Does DTE expect all 1,063 identified customers to connect to the gas system within five years of the Mesick-Buckley project's completion?

A51 Yes. In discovery, Witness Abona states "Due to the low cost and savings as detailed in the EIED application, DTE expects all 1,063 identified customers to choose to connect to the gas system within 5 years of the project's completion."[53]

Q52 Has DTE received commitments to connect from all the prospective new customers it has identified for the Mesick-Buckley project?

A52 No.

Q53 How many customers in the area of the Mesick-Buckley project have actually expressed interest in connecting to it?

A53 DTE does not know. The Company claims that customers have expressed interest but apparently kept no records.[54]

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[52] Ex MEC-12, MNSCDG-1.8h.

[53] Ex MEC-13, discovery response MNSCDG-1.8fi.

[54] Ex MEC-14, discovery response MNSCDG-1.8b.

Q54 Who bears the risk of additional costs if DTE's estimate of the number of customers that connect proves too high?

A54 Witness Abona states that "[i]f volumes/connections are not obtained, DTE shareholders will bear the costs."[55] However, in response to a follow-up question (MNSCDG-4.5a), Witness Abona clarifies that "Prior to the filing of the next general rate case, to the extent sales volumes are not obtained as anticipated would result in lower revenues than those approved by the Commission. These lower revenues would result in lower net income the company earns in that given time period." Witness Abona further clarifies in MNSCDG-4.4bi and MNSCDG-4.4ai that in the next rate case, all assets that are serving customers would be included in the rate base used to calculate rates, and increases or decreases in sales and costs are reset.[56] As a result, the utility would face no risk of lower net income from falling short of expected volumes or connections. This means that, after a short initial period between when an expansion project is complete and the next rate case, all risk of shortfalls in expansion revenues are borne by DTE's ratepayers.

Q55 Is it possible for DTE to collect more revenue than expected from an expansion, and thereby benefit other ratepayers?

A55 In theory, yes, although such an outcome is highly unlikely. To do so, the project would have to exceed at least one of the following conditions while still meeting the other two: connect all customers presently located in the area to be served, make

[55] Ex MEC-15, discovery responses MNSCDG-1.9, 4.4bi, and 4.4ai.

[56] *Id*.

connections as quickly as expected by DTE, and achieve the Company's expectations for sales volumes per customer. Shortfalls in any of these areas would need to be more than overcome by overperformance in another area for there to be a net benefit to other ratepayers.

Q56 Does the payment of contributions in aid of construction mitigate stranded cost risk associated with future reductions in gas use as part of a pathway to mitigate climate change?

A56 No. Contributions are based on assumptions about how the assets will be used over the first 20 years of their operating life and do not affect how they are treated in the longer term. The depreciation rates used to calculate the customer contributions are based on the same asset lives as other DTE assets of the same types and materials, so there are substantial undepreciated plant balances after 20 years. Given that Michigan's goal is carbon neutrality in 26 years, expansion projects add to DTE's potential stranded asset risk.

Q57 Overall, is the risk and reward symmetrical for DTE ratepayers, between under- and over-projections of customer connections and sales?

A57 No, it is not symmetric. Decarbonization that would lead to net costs being borne by ratepayers is much more likely than unexpected high growth leading to net benefits.

Q58 Does DTE track whether the volumes and connections are, in fact, obtained?

A58 In part. DTE does not track the volumes of gas sold to customers by expansion project. DTE was able to provide data regarding the number of connections achieved for each project.

Q59 Could you please summarize the data that DTE provided on customer connections for recent community expansion projects?

A59 Yes. Upon request, DTE provided responses for 15 projects with more than 300 anticipated customers.[57] The following table shows the projected number of customers at the time of project approval and the actual number of customers connected to date for each project.

Project	Projected Customers	Connected to Date	Shortfall
Ellsworth	371	201	170 / 46%
NW Torch Lake	692	446	246 / 36%
Elk Tip	319	191	128 / 40%
NE Torch Lake	927	464	463 / 50%
Epsilon/Pickerel Lake	391	334	57 / 15%
Cherry Homes/Northport	340	222	118 / 35%
Evanston	336	237	99 / 29%
Lake Skegemog	324	212	112 / 35%
Myers Lake - Peterson Farms	496	332	164 / 33%
Ferry Road	320	148	172 / 54%
Holton Duck Lake	373	231	142 / 38%
Higgins Lake	419	212	207 / 49%
Arthur St	307	257	50 / 16%
Blue Lake	432	245	187 / 43%
W County Line	348	193	155 / 45%

[57] Projected: MNSCDG-1.12f; Actuals: MNSCDG-4.6d.

Q60 What is the approximate amount by which DTE overestimated the number of customer connections for these projects?

A60 Across all projects, DTE appears to have overestimated customer connections by about 50 percent. That is, for every 300 projected customers, DTE has connected only about 200. On average, DTE appears to get about 80 percent as many customers as expected in Year 1, and by Year 3 (for projects that have been in operation that long), the ratio of actual to projected falls to about two-thirds.[58]

Q61 What does this shortfall in customers mean for DTE ratepayers?

A61 It means that DTE ratepayers not served by these expansion projects are paying a substantial net cost for these expansions, beyond what was projected when the projects were approved.

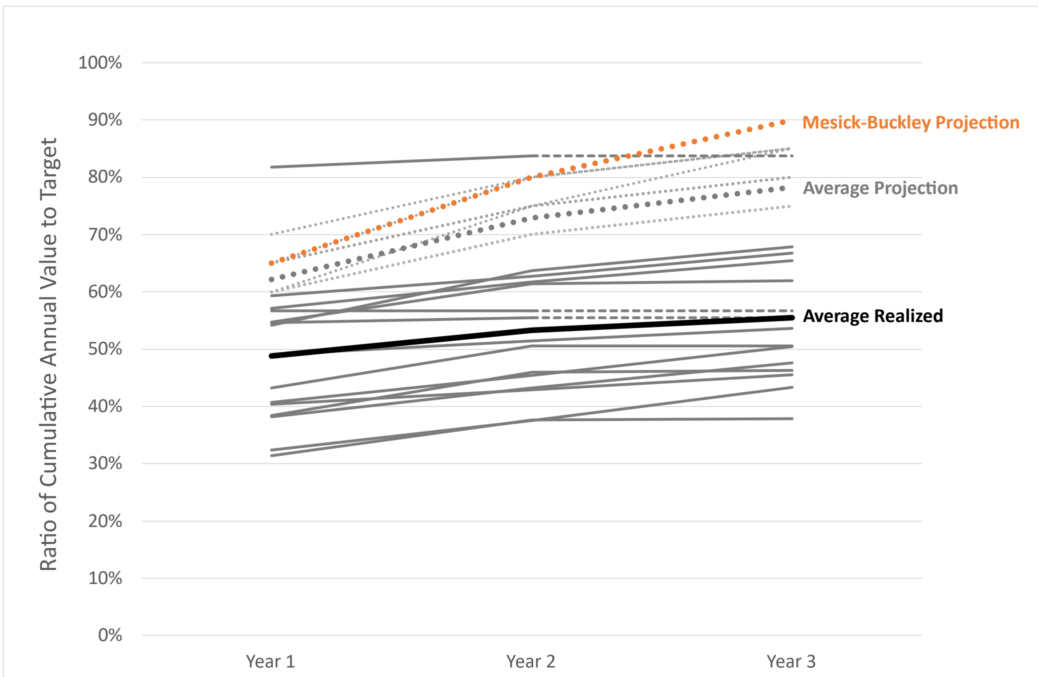
Q62 Based on DTE's experience with customer attachment rates over the last few years, is it reasonable for DTE to assume that all 1,063 identified customers will connect to the Mesick-Buckley project within five years?

A62 No, this is not a reasonable assumption. None of the 15 similar-sized projects from the last few years have approached 100 percent participation. In fact, none of these projects are approaching the level of full subscription over five years. Figure 4 shows the Mesick-Buckley customer connection projection by year (in orange dots) compared with the same projections for the 15 other large projects (light grey dotted lines; average shown in heavy dotted line) and with the actual customer uptake

[58] Projected: U-21291 MNSCDG-4.6f New Customer Attachment Forms; Actuals: MNSCDG-4.6e.

(dark grey solid lines; average shown in heavy black solid line). The Mesick-Buckley projection line is an outlier compared with other projections, and if participation were to follow this line it would be an even greater outlier compared with actual customer growth.

Figure 4. Projected and actual customer connections for DTE expansion projects, shown as fractions of the total target population for each project



Sources: MNSCDG-4.6e, MNSCDG-4.6f Attachment, DTE Low Carbon Energy Infrastructure Enhancement and Development Grant Proposal (Exhibit MEC-16).

Q63 The Mesick-Buckley project cost-revenue analysis assumes miscellaneous customer growth. What is this?

A63 Witness Abona states that "Miscellaneous growth is a mechanism that allows additional new homes and businesses to be accounted for in the project calculations for the first 10 years of the project."[59]

Q64 How much miscellaneous growth does DTE project for the Mesick-Buckley project?

A64 DTE projects growth of 2 percent per year, or about 22 new customers per year.[60] As a result, by the end of the 20-year analysis window for the calculation of the revenue gap, DTE projects the project will serve more than 1,500 customers.[61]

Q65 How does the Mesick-Buckley project's rate of assumed miscellaneous growth compare with the equivalent rates for DTE's 15 other projects with over 300 projected customers from the last few years?

A65 None of the other projects include any assumed miscellaneous growth at all.

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[59] MNSCDG-1.7m.

[60] Exhibit MEC-16. DTE Low Carbon Energy Infrastructure Enhancement and Development Grant Proposal, p. 47.

[61] NDA U-21291 MNSCDG-1.7f Mesick-Buckley Capm 133a Effective 01012022.xls.

Q66 Is it reasonable for DTE to assume that there will be 2 percent annual growth on top of the 100 percent participation among existing buildings potentially served by the Mesick-Buckley expansion?

A66 No, this is not a reasonable assumption. No other recent DTE system expansion project with over 300 projected customers has come close to full subscription, much less demonstrated further "miscellaneous" customer growth beyond the level projected based on existing buildings.

Q67 If the Mesick-Buckley project is typical in its customer adoption rates, how much will other DTE ratepayers be subsidizing the customers served by the project?

A67 If two-thirds of the projected customers sign up, without any additional miscellaneous growth, and DTE charges its projected amount for contributions in aid of construction (i.e., $27.76 per month for residential customers), DTE will face a present-value shortfall of about $838,000. Of this, a small (less than $50,000) net shortfall would result in the first three years and thus may be borne by DTE investors (assuming DTE does not file another rate case within three years), while about $800,000 present value of costs would be borne by DTE's ratepayers as a whole after the assets are all included in rate base at the next rate case. This shortfall calculation assumes that the remainder of DTE's assumptions hold, including the average use per customer and that use staying constant over 20 years.

Q68 Could you please describe how you calculated the present value of the expected shortfall to be about $838,000?

A68 I used the New Customer Attachments file that DTE provided in MNSCDG-1.7f, entitled *NDA U-21291 MNSCDG-1.7f Mesick-Buckley Capm 133a Effective 01012022.xls*. I modified the values on the "CAP Input" sheet to reduce the number of new customers and service lines to two-thirds of the values that DTE used. I also removed all miscellaneous growth. The shortfall is the value for the "Cum[ulative] NPV" presented on the "Cost of Service" sheet.

Q69 Is it reasonable for DTE to shift $800,000 of cost to customers who will not use or benefit from the Mesick-Buckley project?

A69 No, it is not. DTE has used unreasonable assumptions regarding customer connections to this project, and the resulting rates are therefore not just and reasonable.

Q70 If DTE were to adjust the additional monthly customer charge for the Mesick-Buckley customers to account for this average shortfall, what would the new fixed charge be?

A70 The additional fixed connection charge would rise from $27.76 per month to $62.74 per month (or about $753 per year). Commercial customers would pay $5,000 up front (rather than $2,212). These fixed charges are reasonable charges because they reflect reasonable expectations regarding customer connections to this project. I calculated this value using the same file from MNSCDG-1.7f mentioned previously, but this time I adjusted the customer surcharge to achieve a zero net-present-value cost.

Q71 What if DTE also adjusted the timeframe for addressing the revenue deficiency to 2034, as you recommend?

A71 In this case, the additional fixed connection charge would rise from $27.76 per month to $70.20 per month (or about $842 per year). Commercial customers would pay $5,594 up front. These fixed charges are reasonable charges because they reflect a reasonable assessment of the time before which newly connected customers should contribute to the costs of the greater gas system from which they benefit. I calculated this value using the same file from MNSCDG-1.7f mentioned previously, but this time I adjusted the customer surcharge to achieve a zero net-present-value cost, including only the costs and revenues over the first 10 years of operation.

Q72 How would the corrected connection charge affect the economics of electrification with heat pumps compared to pipeline gas?

A72 Assuming that electric heat pumps for space and water heating are about three times as efficient as the fossil fuel equipment being replaced, an average Mesick-Buckley residential customer in this case would save about $439 per year in energy costs by going all-electric rather than signing up for pipeline gas. Their annual cost for electricity would go up about $1,510 versus taking on a gas bill of around $1,948. In other words, electricity would offer about $1125 in annual savings relative to propane while gas would offer $687. Exhibit MEC-7 shows this calculation.

Q73 **Would the policy and market shift toward electrification that you detailed earlier in this testimony make it more likely that Mesick-Buckley customers would choose electricity over pipeline gas?**

A73 Yes. Federal and state incentives for heat pumps and heat pump water heaters will make those technologies more accessible and affordable to households and businesses. Even without correcting the Mesick-Buckley connection charge, the high performance and reduced cost of these technologies may increase the fraction of households that choose not to connect to the gas system.

Q74 **What is a typical useful life of gas mains and service lines?**

A74 These assets generally have engineering lives of more than 50 years.

Q75 **Would extending the cost-revenue calculation beyond 20 years enable the Mesick-Buckley project to break even with the lower ($27.76) connection charge after a few more years, thereby obviating the need for a greater connection charge?**

A75 I estimate that it would take about 50 years for the present value of the reasonably-expected fixed level of sales and customer charges on the Mesick-Buckley expansion to pay off the cost of building the expansion.

Q76 **Is it reasonable to think that the gas system 50 years from now will have the same number of customers and same level of volumetric sales as it does today?**

A76 No, it is not. 50 years from now is 2074, far past 2050, which is the date at which the United States and Michigan have committed to carbon neutrality and net-zero or net-negative emissions. It is not reasonable to assume that Michigan can meet its carbon neutrality plan while retaining all gas throughput and customers. A declining trajectory is likely to occur in subsets of the DTE system, such as the Mesick-Buckley expansion. I conclude that it is unlikely that the increased revenue from the proposed connection charge in this project, along with the spread from customers served by the project, will ever pay off the cost of the expansion. If anything, I expect that customers taking action in line with the energy transition will reduce the income from this project sooner than 20 years, thereby creating even more of a net cost for DTE ratepayers not served by this project.

Q77 What is the Peach Ridge expansion project?

A77 This is a $4.9 million project to serve up to 493 homes in the Peach Ridge Area. DTE states that “DTE Gas has received several inquiries from homeowners in the Peach Ridge area located in the Kent City area. Due to the density of existing homes and potential for additional growth through new homes and subdivisions, this area was economically viable to expand our natural gas facilities to serve the area.”[62]

Q78 Have you conducted a similar analysis of this project to what you have done for Mesick-Buckley?

A78 Yes, I have estimated that DTE will likely experience a revenue deficiency with a present value of about $912,000 if customer attachments for the Peach Ridge project proceed according to DTE’s average experience of customer attachments to expansion projects. Under DTE’s existing practice, this shortfall will be largely

[62] Exhibit A-12, Schedule B5.5, p. 38 of 45.

recovered from other DTE ratepayers who will see no benefit from the Peach Ridge project.

Q79 How did you calculate the $912,000 shortfall?

A79 I used the same approach as previously described for Mesick-Buckley, but this time using the file *NDA U-21291 MNSCDG-8.5 Peach Ridge Capm133a Effective 01012022.xls*, provided in MNSCDG-8.5.

Q80 If DTE accounted for typical under-subscription when setting the customer contributions in aid of construction, and limited subsidies to 2034, what impact would that have on the monthly customer contribution?

A80 Making that correction would increase the contribution from about $44 per month to about $125 per month.

Q81 What impact would these changes in community expansion charges have on the attractiveness of gas versus electricity in Peach Ridge?

A81 At DTE's proposed customer charge addition in Peach Ridge, gas customers would save about $95 per year relative to using efficient electric equipment. In contrast, adjusting to a 10-year deficiency window (2024 to 2034) and accounting for under-subscription would mean savings of $869 per year from choosing electrification instead of gas. See Exhibit MEC-7. DTE's overly optimistic assumptions about customer signups in Peach Ridge are essential to justify the argument that gas is the least-cost option. If more customers instead choose not to adopt gas, aligned with all other recent expansions, all-electric homes will be less expensive to heat. Higher resulting gas rates could drive customers to not sign up for gas, thus exacerbating the revenue deficiency borne by all DTE customers.

Q82 What conclusions do you draw with respect to the cost recovery gap for the 15 large existing expansion projects you evaluated?

A82 None of the 15 projects I examined have fully subscribed (although one has more customers as of now than it was projected to have at this date). Assuming average levels of customer attachments, the Mesick-Buckley project is about $800,000 under-recovered (a bit more than 10 percent of the project's net cost after accounting for the grant funds). The Peach Ridge project is about $900,000 under-recovered—a bit more than 20 percent of that project's cost. Based on this 10- to 20-percent under recovery range, I anticipate that the 15 other projects, which have a combined budget of more than $56 million, likely have an aggregate under-recovery of more than $6 million (present value) and perhaps as much as $11 million, before accounting for cost overruns.

Q83 What do you recommend to the Commission regarding the risk of expansion project undersubscription?

A83 I recommend that the Commission order DTE to use customer adoption rates based on historical experience when calculating new attachment surcharges, and order DTE to gradually sunset subsidies for new attachments by 2034, aligned with my recommendation for individual customers. This approach sets reasonable rates for customer contributions that are fair to both new customers and DTE's existing customers because they are based on real-world experience of customer attachments, reasonable expectations of stable consumption levels, and a fair time before new customers should contribute to the cost of the rest of the gas system.

These values would be $70.20 per month for Mesick-Buckley (or $5,594 up front) and $124.54 per month for Peach Ridge (or $9,925 up front). If DTE is unable to change the values for these projects (for example if customer attachment contracts are already set and DTE is unwilling or unable to change the monthly charge), then the Commission should reduce the allowed revenue requirement by $838,000 for Mesick-Buckley and $912,000 for Peach Ridge.

An alternative, albeit more complex, approach, would be to establish a tracker that shifts the risk of customer attachment decisions from DTE's existing customers to DTE investors and the customers who will utilize the projects. Specifically, DTE investors could bear the final risk for whether sufficient revenue is recovered from each project to cover the cost of the expansion. By shifting risk to DTE's investors, in line with Witness Abona's statement that "[i]f volumes/connections are not obtained, DTE shareholders will bear the costs,"[63] DTE would have an incentive to set appropriate rates for new customers. If DTE were overly optimistic about revenue from customer connections, shareholders would bear the costs. DTE would therefore be more likely to make reasonable assumptions. I would support such an approach, although I think it would be simpler to require DTE to simply use better assumptions from the start.

[63] MNSCDG-1.9.

Q84 Who bears the risk of additional costs if the actual costs to construct a system expansion project exceeds the projected cost?

A84 Witness Abona states that "[a]ny difference resulting from higher or lower costs than those projected and included in this case are initially covered by DTE shareholders and then any differences would be accounted for in DTE Gas's next general rate case."[64] In this way, risk from overruns and underruns in project costs are treated similarly to over- and under-estimates of new customer attachments in a given expansion area: the Company takes a small amount of initial risk but shortly after construction the actual costs are included in rate base and set for full recovery.

Q85 Does DTE do an accurate job of projecting expansion project costs?

A85 No. On average, DTE underestimates the cost to construct community expansion projects by 16 to 17 percent—16 percent on a project-weighted basis and 17 percent on a dollar-weighted basis. The following table shows projected project costs, actual project costs, and overrun percentage for the 15 recent projects targeting over 300 new attachments. The standard deviation of the overrun is 33 percent. That means that the scatter in the cost projection relative to the actual cost is about one-third of the projected cost. The extreme cases are Epsilon/Pickerel Lake, where the expansion cost 79 percent more than expected, and Cherry Homes/Northport, which cost 24 percent less than expected.

[64] MNSCDG-8.4.

Project	Projected Cost	Actual Cost	Over-run %
Ellsworth	2,082,368	1,614,173	-22%
NW Torch Lake	5,454,337	6,959,846	28%
Elk Tip	1,810,511	2,894,945	60%
NE Torch Lake	6,179,193	9,150,395	48%
Epsilon/Pickerel Lake	2,464,620	4,416,825	79%
Cherry Homes/Northport	5,582,000	4,255,178	-24%
Evanston	2,500,000	1,945,053	-22%
Lake Skegemog	2,334,000	1,787,139	-23%
Myers Lake - Peterson Farms	6,542,000	9,382,686	43%
Ferry Road	4,585,000	4,465,323	-3%
Holton Duck Lake	2,761,000	2,824,351	2%
Higgins Lake	2,354,000	2,672,417	14%
Arthur St	3,265,000	4,724,342	45%
Blue Lake	3,905,000	3,885,304	-1%
W County Line	4,731,000	5,322,606	13%
TOTAL	**56,550,029**	**66,300,584**	**17%**

Q86 What is DTE's aggregate overrun for these 15 projects?

A86 It is about $9.75 million.

Q87 If DTE accurately estimated the cost of expansion projects, would that tend to increase or decrease stranded cost risk?

A87 Better estimation would decrease stranded cost risk because it would allow the Company to assign more accurate costs to the customers who are connecting. As it stands, DTE tends to undercharge these customers both because it underestimates the cost of construction and overestimates the number of customers. When DTE under-collects from new customers (due to both of these effects), it puts more risk on its investors and on other ratepayers.

Q88 What do you recommend to the Commission regarding the risk of expansion project cost overruns?

A88 I recommend that the Commission shift the risk of expansion project cost overruns off DTE's existing customers, and onto DTE investors. If the actual cost of the projects were known at the time when the contributions in aid of construction are decided, these contributions would protect other non-benefitting ratepayers from the cost overrun. There is no reason for non-benefitting ratepayers to pay extra simply because the Company underestimated the cost, when they would otherwise be held harmless. The Commission should make clear that cost overruns for expansion projects will face a rebuttable presumption to be imprudent and disallowed. As Company support for system expansion phases out over the period through 2034, there will be reduced need for anyone other than the new customers to take this risk.

VII. THE FUTURE OF HEAT

Q89 Do you have other recommendations to the Commission regarding how it can address issues you raise in your testimony?

A89 Yes. My testimony, as well as that of my colleague Ms. Napoleon, is informed by the fact that meeting state and federal GHG reduction goals will necessarily mean that widespread electrification will change the way Michiganders heat their homes. These changes will have long-lasting and deeply impactful implications for DTE, Michigan's other gas utilities, and the state's electric system. I recommend that the Commission conduct a "Future of Heat" proceeding that would bring all essential utilities and stakeholders together to address this transformation in a manner that will protect ratepayers.

Q90 Why is a separate proceeding appropriate?

A90 A standalone proceeding is appropriate because the future of heat has implications for both electric and gas systems, and a coordinated response on both systems is necessary for the Commission to help the utilities chart a path forward that maintains safe and reliable heating service to all customers throughout the energy transition. Once there is a well-established joint framework, the Commission can expect each utility to bring forward its specific investments and other choices in company-specific dockets.

Q91 Does the need for a Future of Heat docket mean that it is appropriate for DTE to defer consideration of the energy transition in this proceeding?

A91 No. Recognizing the need for coordination among the state's utilities does not obviate the need for DTE to behave prudently and draw upon the best available information in its own planning and proposals in this or any other docket.

Q92 What are the core components of a Future of Heat proceeding?

A92 One core objective for a Future of Heat proceeding should be to develop a shared vision regarding the physical configuration of the future of heating for buildings and industry in a state. In many cases, this requires a study that examines different decarbonization pathways and quantifies the relative advantages and disadvantages of each one. While each state likes to consider itself unique, in practice, such studies conducted by independent analysts tend to follow a common structure and reach similar conclusions: electrification using heat pump technology is the primary cost-effective technology to decarbonize buildings; RNG and other low-carbon fuels are limited, expensive, and generally play a limited role serving end uses that are hard to electrify; and the use of hybrid heating systems can be effective in the near term (noting that using the gas system to serve building heat only on the coldest days creates challenges for the gas utility business model).

Once a common understanding is developed for the physical configuration of the future heating ecosystem, the proceeding moves to evaluating regulatory policy and utility business models. This phase considers:

- the allocation of costs and risk—over time and among customers and utility investors, including detailed analysis of stranded assets, stranded costs, and their mitigation and allocation;
- how to evaluate and implement non-pipeline alternatives and/or clustered or targeted electrification in concert with gas and electric utility capital planning;
- cost allocation for system expansion and new customer attachments;
- electric-gas utility interaction and coordination;
- utility business model innovation and shareholder incentives;
- protections and mitigations for low- and moderate-income customers and communities from adverse customer impacts;
- workforce development and job impacts;
- environmental justice; and
- depreciation approaches for existing and future capital assets.

The energy transition will not a be a "set it and forget it" process—the Commission should plan to revisit these questions on a recurring basis to ensure the transition is on track and to adapt to new technologies, regulatory innovations, and market changes.

Q93 Would Michigan be the first state to conduct a coordinated Future of Heat proceeding?

A93 No, and in fact Michigan can benefit from the work done in other states to scope such proceedings and learn about the issues likely to arise.

Q94 What are some examples that Michigan could use?

A94 The processes in Massachusetts and Rhode Island are illuminating.

Q95 Could you describe the Massachusetts process you reference?

A95 Of course. The Massachusetts Department of Public Utilities (DPU, its regulatory commission) opened Case No. 20-80 in 2020, in part in response to a petition from the state's Attorney General, to investigate how the state's net-zero emissions law would impact the state's gas utilities. The DPU required the state's gas distribution utilities to contract with a consultant team to conduct an independent study of pathways to deep decarbonization and the resulting regulatory implications. The consultant team conducted a series of stakeholder meetings to inform its analysis, then presented its conclusions. The utilities then proposed regulatory steps informed by the consultant work. The DPU issued Order 20-80 in late 2023, drawing upon the full record in the proceeding. I have attached the DPU's order as Exhibit MEC-8. Order 20-80 established a new framework for the gas utility system in Massachusetts, including: (1) an expectation of increased utility support for electrification; (2) rejection of adding RNG to default gas supply portfolios; (3) support for pilots of networked geothermal, targeted electrification, hybrid heating systems, and renewable hydrogen, with the greatest emphasis on networked geothermal and targeted electrification; (4) to dissuade gas customer expansion, adjustment of the decoupling mechanism to eliminate the incentive for customer growth and examine depreciation rates; and (5) placement of the burden on the gas utilities to show that non-pipeline alternatives are non-viable or cost-prohibitive in order to receive cost recovery for new investments. The DPU specifically highlighted the need to reexamine how costs are allocated for expansion to serve new customers, and it directed the gas utilities to review policies and tariffs to determine whether current practices accurately reflect how capital investments will be recovered (among other considerations). Finally, the DPU ordered that each gas utility prepare and submit Climate Compliance Plans every five years, to be developed in coordination with electric distribution companies.

Q96 What process lessons do you draw from the Massachusetts example?

A96 The Massachusetts process had a number of promising features, but also some shortcomings. On the positive side, the use of an independent consultant to conduct analysis provided important shared facts for all parties in the proceeding. The scope of the consultants' pathways and regulatory studies was appropriately broad and covered important aspects of cost, risk, and equity. The stakeholder input process also held great promise, and the recurring Climate Compliance Plan process will provide an opportunity for revision and course correction. However, some participants found the stakeholder process to be frustrating because the consultants were not required to incorporate any of the suggestions or concerns raised by stakeholders.[65] The consultants were selected and hired by the utilities, and that colored how their results were received. Further, one potential advantage of being hired by the utilities was lost: the consultants were not granted access to any non-public information about the gas system. By putting the gas utilities in the center of this process, the DPU also sidelined the important contributions that the electric utilities could have provided regarding impacts on and of their systems.[66] Based on this experience, I would recommend that Michigan not rely on its gas utilities to oversee or conduct the primary analysis in a Future of Heat proceeding.

Q97 Could you describe the Rhode Island process you reference?

A97 The Rhode Island Public Utilities Commission ("RIPUC") opened a Future of Gas proceeding on its own initiative in June 2022. The RIPUC began the process by consulting with stakeholders to establish the scope for a study to be conducted by

[65] Gandbhir, P. Dec. 8, 2022. *Building a Successful Future of Gas Proceeding*. Presentation to the Connecticut 2022 Comprehensive Energy Strategy Technical Session 7. On behalf of Conservation Law Foundation. See https://portal.ct.gov/deep/energy/comprehensive-energy-plan/comprehensive-energy-strategy and https://ctdeep.zoom.us/rec/play/aoHZ0bFjyoimFGQIvLNedPni0JFEtH8asoPTHwy66J13xC27kKqgwBV3q2ZW1Adp69AKOKr4XhxbYGOA.75oC4K8rPVzfoFZ2?startTime=1670508004000&_x_zm_rtaid=uom_SMlKRpivO-62XizETg.1670871656268.fe90398f6d04d63e3a6591ca10f5a11a&_x_zm_rhtaid=953 beginning circa 4:33 timestamp.

[66] Massachusetts's largest gas utilities, as in Michigan, are dual-fuel utilities and share a corporate parent with an electric utility. However, the electric utility service territories are largely disjoint from the gas territories and the electric utilities are run as relatively separate organizations.

an independent consultant, who would be contracted to the RIPUC. After developing the scope, the RIPUC contracted with a consulting firm, which has conducted a study. The consultant held a series of stakeholder working group sessions to vet assumptions, develop scenarios, and receive feedback on methods and results. The gas utility, Rhode Island Energy, participated in these stakeholder meetings and provided information requested by the consultants. Rhode Island Energy is also the state's dominant electric utility; but unfortunately, the electric utility staff were less engaged. This was in part because the study was framed as the future of gas, rather than the future of heat. I would recommend that electric and gas utilities be equal stakeholders in a future of heat proceeding to avoid this asymmetry. As of this writing, the RIPUC has not issued an order addressing the results of the study.

Q98 What process lessons do you draw from the Rhode Island example?

A98 The RIPUC learned from the Massachusetts example and improved upon the process for scoping and conducting analysis. Specifically, the RIPUC consulted extensively with stakeholders to set the scope for the study and contracted with the consultant directly. This should result in more stakeholder trust of the final analysis. By empowering the consultant through the imprimatur of the RIPUC, the consultants were able to access important utility data and insights in an open way that educated all stakeholders.

Q99 Could you summarize your recommendations regarding the Future of Heat?

A99 I recommend that the Commission open a "future of heat" proceeding with the following characteristics:

- Required engagement from all electric and gas utilities in the state;
- An open process for stakeholder participation;
- A participatory process to set the scope for the proceeding and required analysis;
- Learnings from similar processes conducted in other places;
- Expert advice, analysis, and modeling conducted on behalf of the Commission; and
- Explicit goals to develop both (1) a shared understanding of the range of policy-consistent futures for building and industrial heat in Michigan, including an expected pathway to use for planning, and (2) a set of regulatory and policy tools to use in pursuing that pathway and adapting utility finance and business models to it.

Q100 Does this conclude your testimony at this time?

A100 Yes, it does.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, April 2019 – present, *Principal Associate*, January 2017 – March 2019.

Conducts research and writes expert testimony and reports related to state energy policy and planning, energy efficiency, strategic electrification, deep decarbonization, and the present and future of electric and gas utility regulatory and business models.

Vermont Public Service Department, Montpelier, VT. *Director of Energy Policy and Planning,* October 2011 – December 2016

State energy planning and utility regulation

- Directed the year-long development of the 2016 Vermont Comprehensive Energy Plan, including stakeholder meetings, public forums, and coordination of contributions from other departments and the Governor's office. Primary author of the executive summary and five chapters.
- Led the Department's approach to establishing budgets and performance targets for energy efficiency utilities. Oversaw staff conducting program evaluation and savings verification.
- Submitted testimony and conducted analysis in support of public advocacy and negotiation in prominent litigated regulatory proceedings.

Policy development, analysis, and advocacy

- Developed the structure of Vermont's 2015 Renewable Energy Standard, including its novel "energy transformation" requirement. Worked with stakeholders to develop support for the policy and with the legislature to shepherd it to passage. This policy will result in more reduction of Vermont's GHG emissions than any others passed in the last 15 years.
- Led execution of Vermont's Total Energy Study, which examined technology and policy pathways for Vermont to meet GHG emission and renewable energy goals.
- Led cost-benefit analysis of Vermont's existing net metering structure and led the development of departmental proposals for a new structure.
- Prepared and delivered public, stakeholder, and interagency presentations, including to agency and business leaders, legislative committees, and the governor.
- Oversaw programs providing financing, technical, and process assistance to clean energy projects.

During tenure, Vermont rose in the rankings on national clean energy state scorecards: ACEEE State Energy Efficiency Scorecard from 5th to 3rd and U.S. Clean Tech Leadership Index from 10th to 3rd.

U.S. Department of Energy, Washington, DC. *Special Advisor to the Under Secretary for Science / AAAS Science and Technology Policy Fellow,* September 2010 – August 2011

Dr. Hopkins served as the assistant project director for the Department of Energy's first Quadrennial Technology Review. In this role, he coordinated a team that solicited input from Department of Energy and National Laboratory staff and scientists, ran a series of public workshops, facilitated coordination with the White House, developed a set of technology assessments, and ultimately drafted the Report on the First QTR, published Sept. 27, 2011.

Lawrence Berkeley National Laboratory, Berkeley, CA. *Environmental Energy Policy Postdoctoral Fellow*, January 2009 – August 2010

Conducted technical and economic analysis to support the Department of Energy in setting the energy efficiency standards that appliances must meet in order to be sold in the United States.

California Institute of Technology, Pasadena, CA. *Graduate Research Fellow,* 2002 – 2008

Los Alamos National Laboratory, Los Alamos, NM. *Post-Baccalaureate Researcher, Theoretical Division,* June 2001 – June 2002

EDUCATION

California Institute of Technology, Pasadena, CA
Doctor of Philosophy in Physics, 2008
Master of Science in Physics, 2007

Haverford College, Haverford, PA
Bachelor of Science *summa cum laude*, in Physics with minors in Computer Science and Growth and Structure of Cities, 2001

SELECTED PROJECTS

The Future of Gas Utilities – Dr. Hopkins leads Synapse's work in the area of the future of gas utilities. He and his team are assisting a number of clients to understand the future of gas utilities in the context of deep building decarbonization objectives. This work includes assisting Conservation Law Foundation in Massachusetts Department of Public Utilities Docket 20-80 (an investigation into "the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals"); the Industrial Gas Users Association in evaluation of energy-transition-related business risk to Quebecois and Ontario gas utilities; Natural Resources Defense Council in New York and Nevada's regulatory proceedings regarding the future of gas; the Colorado Energy Office regarding approaches to decision-making in the face of uncertainty, in the context of Colorado's regulatory proceedings regarding gas utility Clean Heat plans and building decarbonization; the County of San Diego (with the University of California San Diego) in developing the buildings and utilities portion of its Regional Decarbonization Framework; the Maryland

Office of People's Counsel in modeling the impact of the state's decarbonization objectives on utility sales and finances; and the District of Columbia Department of Energy and Environment in assessing Washington Gas Light's Climate Business Plan and rate case filings.

Puerto Rico Energy Bureau – Synapse has provided extensive support to Puerto Rico's electricity regulator since 2015. Dr. Hopkins has coordinated the engagement since 2018. Dr. Hopkins has led or substantially contributed to the development of Puerto Rico's first energy efficiency and demand response regulations; emergency microgrid regulations; and the review of the island's second Integrated Resource Plan and subsequent processes to optimize resilience using both transmission and distributed generation resources.

Massachusetts Comprehensive Energy Plan – On behalf of the Massachusetts Department of Energy Resources (the state energy office), Synapse and Sustainable Energy Advantage assisted DOER and its sister agencies in the development of Massachusetts's first Comprehensive Energy Plan. Dr. Hopkins assisted DOER leadership in defining the scope and approach for the CEP, to distinguish it from other state planning processes. He worked with Pat Knight to develop an approach to modeling energy transformations toward low-carbon alternatives in electricity, buildings, and transportation that are consistent with state policy and approaches while being grounded in stock turnover rates and feasible policies and programs.

Northeastern Regional Assessment of Strategic Electrification – On behalf of the Northeast Energy Efficiency Partnerships, Synapse and Meister Consultants Group identified the opportunity, costs, and benefits available if strategic electrification is adopted as a key strategy for decarbonization in New York and New England. Dr. Hopkins, Kenji Takahashi, and Pat Knight are primary authors of the resulting report, published in July 2017, which characterizes the current markets for efficiency electrification technologies (such as heat pumps and electric vehicles), identifies policies to overcome market barriers, assesses the state of electrification technologies, and models the extent of electrification both possible given market dynamics and required to meet regional greenhouse gas emission goals.

2016 Vermont Comprehensive Energy Plan – Directed the year-long development of the 2016 plan, including setting its strategic approach to current Vermont energy planning challenges and grounding it in quantitative analysis. Developed the public engagement process, then hosted expert stakeholder meetings and public forums. Adapted the results of the 2014 Total Energy Study to produce scenarios that illustrate the proposed pathways identified in the plan. Coordinated contributions from staff and leaders in other departments, and from the Governor's office. Wrote the executive summary and 5 of the 14 chapters.

Total Energy Study – Scoped and led a legislatively-mandated report on policy and technology pathways to meet Vermont's renewable energy and greenhouse gas emission goals. Designed and facilitated a focus-group-based stakeholder engagement process to identify technology and policy visions for analysis. Retained outside modeling consultant, then worked closely with them to build credible business-as-usual and policy case models of Vermont's energy economy to the year 2050 using the

TIMES/FACETS integrated assessment model. Translated those model results to make REMI PI+ calculations of impact on Vermont GDP and jobs. Synthesized qualitative and quantitative results into intermediate and final reports identifying key outcomes for policy design.

Demand Resources Plan Proceedings – In each of three, three-year cycles, led the development of the Department of Public Service's positions regarding appropriate budgets, rate and bill impacts, and performance targets for Vermont's energy efficiency utilities. Analyzed current efficiency utility performance to calibrate expected future performance. Negotiated performance metrics that reflect policy priorities. Developed new regulatory and budget treatment of research and development for behavioral energy efficiency programs.

Quadrennial Technology Review – As Assistant Project Director, managed the project activities of the eight-person core team for the U.S. Department of Energy's first Quadrennial Technology Review. This review of DOE's energy technology activities established a robust framework and codified principles used to build DOE's energy technology portfolio (including identifying the appropriate and highest-leverage activities for DOE relative to the private sector and other government actors). Extensive collaboration and discussions within DOE, as well the public through a series of workshops with industry, government, national laboratory, and academic participation, culminated in the publication of the first DOE-QTR report in September 2011. Coordinated successful stakeholder workshops; facilitated focus groups. Drafted discussion papers that served as the basis for extensive intra- and inter-agency and White House coordination and negotiation. Primary author of the final report's section on building and industrial energy efficiency. Project was completed on schedule and on budget, and met its critical milestones.

REPORTS

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Hopkins, A.S., P. Knight, J. Frost. 2021. *Rhode Island Carbon Pricing Study.* Synapse Energy Economics and the Cadmus Group for the Rhode Island Office of Energy Resources.

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Hopkins, A. S., S. Fields, T. Vitolo. 2017. *Policies to Cost-Effectively Retain Existing Renewables in New York*. Synapse Energy Economics for the Alliance for Clean Energy New York.

Vitolo, T., A. S. Hopkins. 2017. *The Mounting Losses at CWLP's Dallman Station: A Study of the Relative Costs of Operating Each of the Four Dallman Units*. Synapse Energy Economics for the Sierra Club.

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TESTIMONY

Connecticut Public Utilities Regulatory Authority (Docket No. 23-11-02): Direct and surrebuttal testimony regarding the application of Connecticut Natural Gas Corporation and the Southern Connecticut Gas Company to amend their rate schedules, with focus on gas capital planning in the context of decarbonization. On behalf of the Connecticut Office of Consumer Counsel, February and March 2024.

Public Utilities Commission of the State of Colorado (Proceeding No. 23A-0392EG): Answer and cross-answer regarding the application of Public Service Company of Colorado for approval of its 2024-2028 Clean Heat Plan, with focus on rate and bill impacts. On behalf of Sierra Club and Natural Resources Defense Council, January and February 2024.

Maryland Public Service Commission (Case No. 9692): Direct and Surrebuttal Testimony of Asa Hopkins regarding the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People's Counsel, August 2023.

Ontario Energy Board (EB-2022-0200): Testified as an expert on the business risk facing Enbridge Gas, Inc. related to the energy transition and other risks, as part of a rate case proceeding to set the utility's capital structure. On behalf of the Industrial Gas Users Association, 2023.

Washington DC Public Service Commission (FC 1169): Provided direct and rebuttal expert testimony regarding Washington Gas's application for an increase in rates, from the standpoint of the District of Columbia's climate and clean energy policies. On behalf of the District of Columbia Government, November 2022 and January 2023.

New York Public Utilities Commission (Case No. 22-E-0064 and 22-G-0065): Direct and Rebuttal Testimony of Alice Napoleon and Asa Hopkins regarding Con Edison's proposed gas-side investments as greenhouse gas mitigation strategies and gas extension allowance rule changes and the need for long-term planning for the gas system and adequacy of the company's non-pipe alternatives framework. On behalf of Natural Resources Defense Council, May 2022.

Régie de l'énergie du Québec (R-4156-2021): Testified as an expert on the business risk facing Quebec's natural gas utilities related to the energy transition, as part of a proceeding to set the utilities' cost of capital and capital structure. On behalf of the Industrial Gas Users Association, 2022.

Vermont Public Utility Commission (Case No. 21-1107-PET and 21-1109-PET): Addressed the impact of GlobalFoundries proposed “self-managed utility” on the general good of the state and Vermont’s energy policy, with particular focus on the impact on environmental soundness and greenhouse gas emissions mitigation. On behalf of Conservation Law Foundation, June 2021.

Public Service Commission of Wisconsin (Docket No. 5-CG-106): Addressed the need for a pair of liquified natural gas facilities in light of the fossil fuel use reductions required to meet state and federal goals for mitigating climate change and the potential for cost-effective demand-side alternatives. On behalf of the Sierra Club, June 2021.

Vermont Senate Finance Committee: Provided expert testimony in the form of a presentation entitled “Updating Vermont’s Renewable Energy Standard” to the Vermont Senate Finance Committee in January of 2020. Dr. Hopkins presented on the history of the standard, what has changed since 2015, and future potential.

Vermont Public Utility Commission (Case No. 17-1247-NMP): Addressed the consistency of a proposed solar generation facility with the Vermont Comprehensive Energy Plan. On behalf of Derby GLC Solar LLC, January 2018.

Washington DC Public Service Commission (FC 1142): Provided expert testimony regarding the merits of the proposed merger of Washington Gas and AltaGas, Ltd. with respect to the impact on environmental quality, with particular emphasis on the impact of utility management and its approach to climate change on the ability of the District to achieve its climate change mitigation goals. On behalf of the District of Columbia Government.

Régie de l’énergie du Québec (R-3986-2016): Provided an expert report and testimony regarding best practices in utility demand response programs, in the context of Hydro Québec Distribution’s ten-year Supply Plan. On behalf of the Regroupment national des conseils régionaux de l’environment du Québec (RNCREQ).

Vermont Public Service Board (Dockets No. 8586 and 8685): Addressed the need for a proposed solar PV generator and its associated contract under PURPA rates, its economic impact on the state, and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, July 2016.

Vermont Public Service Board (Docket No. 8684): Proposed avoided energy and capacity cost rates for use in Rule 4.100, Vermont’s implementation of PURPA. On behalf of the Vermont Department of Public Service, October 2015 and May 2016.

Vermont Public Service Board (Docket No. 8600): Addressed the need for a proposed solar PV generator, its economic impact on the state, and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, March 2016.

Vermont Public Service Board (Docket No. 8525): Introduced a memorandum of understanding between the DPS and Green Mountain Power regarding a proposed rate design, with particular focus on new critical peak price rates to be available and marketed. On behalf of the Vermont Department of Public Service, November 2015.

Vermont Public Service Board (Docket No. 7970): Addressed whether increases in the expected cost of a gas pipeline expansion project were sufficient to warrant reopening the underlying proceeding, particularly with respect to the need for the project, the economic impact on the state, and consistency with the general good of the state and the Vermont Comprehensive Energy Plan. On behalf of the Vermont Department of Public Service, May 2015.

Vermont Public Service Board (Docket No. 8311): Addressed how statutory criteria for the use of electric energy efficiency funds for electrification measures (such as heat pumps) might be met. On behalf of the Vermont Department of Public Service, January 2015.

Vermont Public Service Board (Docket No. 7862): Presented the Department's positions regarding whether Entergy Vermont Yankee should be granted a continued certificate of public good, with particular focus on the need for the plant, the economic benefit of continued operation, consistency with the Vermont Electric Plan, and whether continued operation by Entergy was in the general good of the state. On behalf of the Vermont Department of Public Service, October 2012 and April 2013.

Vermont Public Service Board (Docket No. 7833): Addressed the need for a proposed biomass electric generator and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, October and November 2012; February and September 2013.

Vermont Public Service Board (Docket No. 7770): Addressed a number of topics related to the merger of Green Mountain Power and Central Vermont Public Service, most particularly the disposition of a windfall repayment due to ratepayers. On behalf of the Vermont Department of Public Service, January and March 2012.

Vermont Public Service Board (Docket No. 7815): Addressed consistency of a proposed long-term PPA with the Vermont Electric Plan and the utility's integrated resource plan. On behalf of the Vermont Department of Public Service, January 2012.

SELECTED PRESENTATIONS

Hopkins, A. S., S. Kwok, A. Napoleon, K. Schultz, K. Takahashi. "Massachusetts Clean Heat Standard: Policy and Regulatory Analysis" presented with Conservation Law Foundation, February 2023.

Hopkins, A. S. "IIJA, IRA, and the Growing Federal Role in Transmission—and Why States Should Care," presented at the National Association of State Energy Officials Annual Meeting, October 2022.

Hopkins, A. S., J. Litynski, A. Takasugi. "Policy approaches to increasing electricity affordability in California," presented to various California stakeholders on behalf of Natural Resources Defense Council, February 2022.

Shipley, J., Hopkins, A. S., Takahashi, K., & Farnsworth, D. "Renovating regulation to electrify buildings: A guide for the handy regulator," presented with Regulatory Assistance Project, January 2021.

Hopkins, A. S. 2019. "Efficiency, Electrification, and Renewables in New England and Puerto Rico" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Hopkins, A. S. 2019. "Strategic electrification and winter cold snaps: A resource and a challenge" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Panelist on "Deep Dive Session on State and Local Electrification Roadmaps" at Electric Power Research Institute (EPRI)/Northeast Energy Efficiency Partnerships (NEEP) Electrification Summit, August 2019.

Hopkins. A. S., K. Takahashi, D. Lis. 2018. "Decarbonization through Strategic Electrification Meets Utilities and Regulation in the Northeast" at the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 2018.

Hopkins, A. S. 2019. "Strategic Electrification: Impacts and approaches to meeting decarbonization goals in the northeastern states (and elsewhere)" at Lawrence Berkeley National Laboratory, Energy Technologies Area, August 2018.

Hopkins, A. S. 2017. "Utility Performance Regulation" at the Western States Regional Meeting of the National Association of State Energy Officials, April 2017.

Panelist on "A Regulatory Perspective of Grid Transformation" at the IEEE Innovative Smart Grid Technologies Conference, September 2016.

Panelist on the "Comprehensive Energy Plan Update" at the Renewable Energy Vermont Conference, October 2015.

Hopkins, A. S. 2015. "Vermont's Total Energy Study." Presentation at the National Association of State Energy Officials Energy Policy Outlook Conference, February 2015.

Panelist on "The Role of Energy Efficiency in Mitigating Winter Peak Issues" at the Association of Energy Services Professionals (Northeast Chapter) & Northeast Energy Efficiency Council, November 2014.

Hopkins, A. S. 2014. "Total Energy Study." Presentation at the Renewable Energy Vermont Conference, October 2014.

Panelist on "State Energy & Economic Policy Impacts on Industry Transformation" at the Power Industry Transformation Summit, April 2014.

Hopkins, A. S. 2008. "Mobilizing Pasadena Democrats: Measuring the Effects of Partisan Campaign Contacts." Presentation at the American Political Science Association Annual Meeting, August 2008.

HONORS, AWARDS, AND FELLOWSHIPS

Certified Public Manager, 2014

AAAS Science and Technology Policy Fellowship, 2010 – 2011

Dean's Award for Community Service, 2009

Delegate to the 2004 Democratic National Convention

NSF Graduate Research Fellow, 2002 – 2005

Los Alamos National Laboratory Student Distinguished Performance Award, 2002

Two-time first-team Academic All American, 2000 and 2001

Barry M. Goldwater Scholar, 1999 – 2001

OTHER ACTIVITIES

NASEO - Electricity Committee: Affiliate Co-Chair, 2020-present

Newton, MA Citizens Commission on Energy: Member 2017-present, Co-Chair 2023-present

Guest on Synapse Energy Economics, Inc.'s *Energy Nerd Show,* Aug 6, 2020

Board Member, National Association of State Energy Officials, 2015-16

Industrial Advisory Board for ARPA-E-funded project "Packetized Energy Management," 2016

Burlington, VT Public Works Commission: Member 2012 –2014, Chair 2015

Resume updated April 2024

Michigan Renewable Natural Gas Study

Final Report

September 23, 2022

Submitted to:
Michigan Public Service Commission

Submitted by:
ICF Resources, L.L.C.
9300 Lee Highway
Fairfax, VA 22031

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List of Abbreviations

AD	Anaerobic digestion
AGF	American Gas Foundation
ATB	Advanced Technology Baseline
CAFO	Concentrated animal feeding operation
CCST	California Council on Science and Technology
CH4	Methane
CI	Carbon intensity
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CWC	Cellulosic Waiver Credit
CWNS	Clean Watersheds Needs Survey
DGE	Diesel gallon equivalent
DOE	United States Department of Energy
EFI	Energy Futures Initiative
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
EREF	Environmental Research & Education Foundation
gCO_2e/MJ	grams of CO_2e per megajoule
GHG	Greenhouse gas
H2S	Hydrogen sulfide
HHV	Higher heating value
IOU	Investor-Owned Utilities
KDF	Bionergy Knowledge Discovery Framework
LCFS	Low Carbon Fuel Standard
LCOE	Levelized cost of energy
LFG	Landfill gas
LFGE	Landfill gas to electricity
LMOP	Landfill Methane Outreach Program
M&HDV	Medium- and heavy-duty vehicle
MGD	Million gallons per day
MMBtu	Million British thermal units
$MMtCO_2e$	Million metric tons of CO_2e
MOU	Municipally-Owned Utilities
MSW	Municipal solid waste
N_2	Nitrogen
NGV	Natural gas vehicle
O_2	Oxygen
P2G	Power to gas
PA-CAP	Pennsylvania Climate Action Plan
PEM	Proton exchange membrane
POLYSYS	Policy Analysis System
REC	Renewable Energy Certificate

RFS	Renewable Fuel Standard
RIN	Renewable Identification Number
RNG	Renewable natural gas
RPS	Renewable Portfolio Standard
RVO	Renewable Volume Obligations
SCFM	Standard cubic feet per minute
tBtu	Trillion British thermal units
tCO_2e	Metric ton of CO_{2e}
Tpd	Tons per day
USDA	United States Department of Agriculture
WRI	World Resources Institute
WRRF	Water resource recovery facilities
ZEV	Zero emission vehicle

Executive Summary

This study is in response to the directives of Michigan Public Act 87 of 2021, which requires the Michigan Public Service Commission to conduct a study into the potential for renewable natural gas development in the state. ICF developed this study to provide data and accompanying analysis regarding renewable natural gas production potential in Michigan to help inform policymakers and decisionmakers. Stakeholder engagement included hosting three public meetings dedicated to receiving stakeholder input, soliciting peer-reviewed studies that would enrich this study, providing multiple documents that were used to develop the study's structure and findings for stakeholder review, providing stakeholders an opportunity to submit comments regarding the methodologies and assumptions employed in this study, and providing stakeholders an opportunity to submit comments regarding the draft version of this study.[1] Furthermore, the Michigan Public Service Commission accommodated multiple meeting requests from stakeholders regarding this study and incorporated stakeholder comments throughout the process.

The timing of this report is critical as the market for biogas and renewable natural gas is in transition. Biogas already plays a role in Michigan's renewable energy landscape, most notably by generating electricity to help comply with Michigan's Renewable Portfolio Standard. Michigan benefits from a variety of investments that have been made to capture biogas for beneficial use. Today, about 40 Michigan landfills have installed more than 135 megawatts of electricity generation, and five landfills in Michigan have so-called direct use applications, which uses biogas in boilers or other direct thermal uses.

As a result of policy changes at the federal level, however, the biogas market has undergone significant changes over the last eight years. During that time, investments in biogas-to-electricity projects slowed and the market shifted towards producing renewable natural gas for pipeline injection. Rather than using biogas to generate electricity for use on-site or selling it into electricity markets, that biogas is now upgraded and processed so that it can be injected into common carrier pipelines as renewable natural gas.

Today, there are at least six operational renewable natural gas projects at Michigan landfills, with two to three more expected to be online by early 2023. Similarly, there are at least four operational anaerobic digesters in Michigan that produce renewable natural gas from the capture of methane emitted from animal manure, and at least another three that have broken ground and will be fully operational towards the end of 2022. While most of the renewable natural gas produced in Michigan today is used as a transportation fuel, there is emerging demand for renewable natural gas in non-transportation applications.

In this study, ICF characterizes the potential for renewable natural gas as a greenhouse gas emission reduction strategy in the State of Michigan, including a review of how much renewable natural gas could be produced from in-state resources, the associated cost of producing renewable natural gas, an assessment of how renewable natural gas compares to other

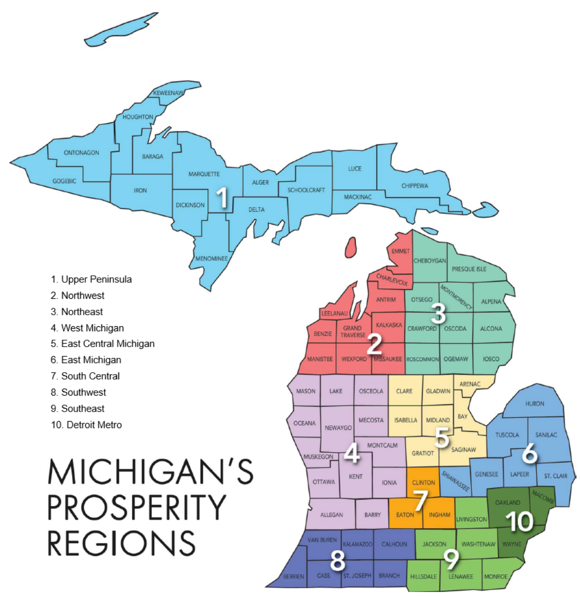
[1] Stakeholder comments are available on the MPSC's Renewable Natural Gas Study Workgroup website.

potential abatement strategies, and a review of the opportunities and barriers that exist to renewable natural gas production, including environmental impacts.

Public Act 87 of 2021 defines renewable natural gas as "a biogas that has been processed or upgraded to be interchangeable with conventional natural gas and to meet pipeline quality standards or transportation fuel grade requirements." Because renewable natural gas is a 'drop-in' replacement for natural gas, it can be safely employed in any end use typically fueled by natural gas, including space heating and cooling, industrial applications, transportation, and electricity production.

RNG Production Potential in Michigan

ICF developed three resource potential scenarios by considering renewable natural gas production from nine feedstocks and two production technologies. The feedstocks include landfill gas, animal manure, water resource recovery facilities, food waste, agricultural residues, forestry and forest product residues, energy crops, and the biogenic fraction of municipal solid waste. These feedstocks were assumed to be processed using anaerobic digesters or thermal gasification systems. ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks for renewable natural gas production.



ICF estimated renewable natural gas potential at the county level across Michigan and included facility-level information for relevant feedstocks where available (e.g., for landfills and water resource recovery facilities). While the underlying data is collected for all 83 counties in Michigan, in this report we aggregate and present the data based on Michigan's ten prosperity regions.[2] ICF developed a maximum renewable natural gas potential for each feedstock and production technology in Michigan, reported in trillion British thermal units per year (tBtu/y). The renewable natural gas potential includes different variables for each feedstock, but ultimately reflects the most aggressive options available to achieve maximum renewable natural gas production potential.

[2] https://www.michigan.gov/images/mshda/MI-prosperity-regions-map-LG_616814_7.png

ICF also developed renewable natural gas supply curves for two additional scenarios for each feedstock and region included in the renewable natural gas inventory. The renewable natural gas potential scenarios included in the supply curves are based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, renewable natural gas costs, technological development, and the policies in place that might support renewable natural gas project development. ICF assessed the renewable natural gas resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are). The two supply scenarios are characterized as achievable and feasible:

- **Achievable** represents a low level of feedstock utilization, with utilization levels depending on feedstock, with a range from 20% to 50% of technically available feedstocks that were converted to renewable natural gas using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario is 30%, at lower biomass prices. Overall, the Achievable scenario captures 18% of the renewable natural gas feedstock resource in Michigan.
- **Feasible** represents balanced assumptions regarding feedstock utilization, with a range from 60% to 85% for feedstocks that were converted to renewable natural gas using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranges from 40% to 50% at moderate biomass prices. Overall, the Feasible scenario captures 47% of the renewable natural gas feedstock resource available in Michigan.

The table below includes renewable natural gas supply estimates for 2050 from in-state resources using the constraints that ICF developed for the Achievable and Feasible scenarios; the last column shows the maximum development potential for each feedstock in 2050 based on the feedstock inventory developed (reported in units of trillion British thermal units per year).

Maximum Renewable Natural Gas Production Potential by Feedstock (tBtu/y)

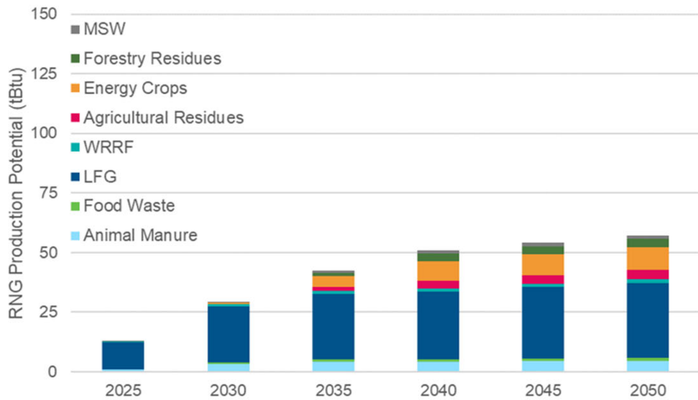
RNG Feedstock		Scenario		
		Achievable	Feasible	Inventory
Anaerobic Digestion	Animal Manure	4.6	9.3	39.0
	Food Waste	1.2	1.8	3.0
	LFG	31.5	53.5	67.8
	Water Resource Recovery Facilities	1.5	2.3	3.5
Thermal Gasification	Agricultural Residue	3.8	30.3	69.9
	Energy Crops	9.6	42.0	112.3
	Forestry and Forest Product Residue	3.5	5.9	11.8
	Municipal Solid Waste	1.5	3.1	6.1
Total		**57.2**	**148.0**	**313.4**
Percentage of Total Available Feedstock[3]		**18%**	**47%**	**100%**

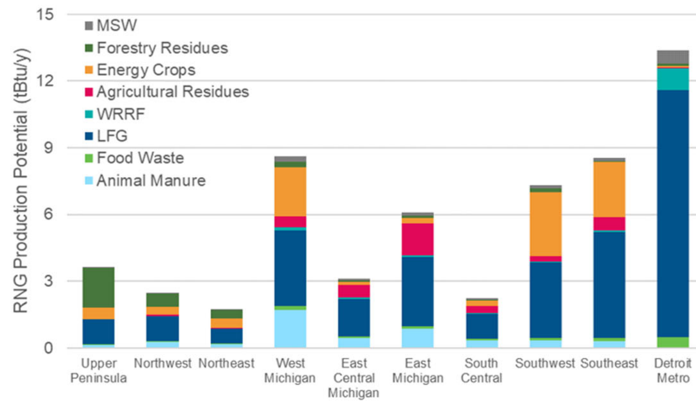
The renewable natural gas resources in Michigan are diverse, including significant potential from landfills, municipal solid waste, animal manure, and energy crops. The variety in renewable natural gas feedstocks is driven by the diverse nature of Michigan's renewable resources, including the mix of rural areas with agricultural activity and significant population centers that provide a source of biomass-based waste. For the sake of reference, Michigan consumed an average of 673 tBtu of natural gas in residential, commercial, and industrial, and vehicle sectors from 2016 to 2020, with a minimum of 642 tBtu in 2020 and a maximum of 713 tBtu in 2019.[4] In other words, ICF's estimates for renewable natural gas deployment in Michigan for the Achievable and Feasible scenarios amount to 8.5% and 22.0% of the average annual natural gas consumption in relevant sectors for the last five years for which there are data available.

The figure below shows four graphs, outlining the renewable natural gas production potential for each feedstock out to 2050, and the corresponding renewable natural gas production potential for each region in 2050. The top two graphs correspond to the Achievable scenario, whereas the bottom two graphs correspond to the Feasible scenario.

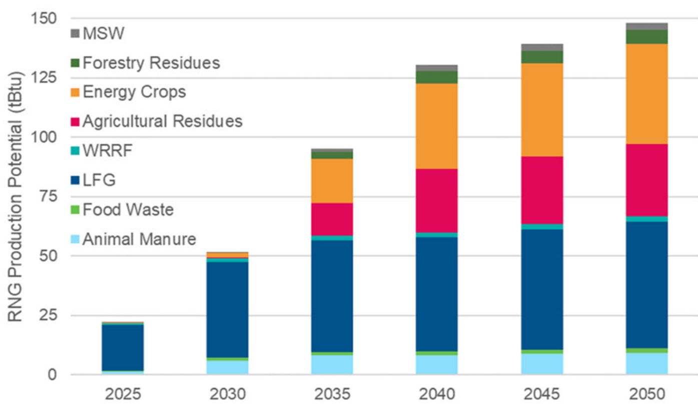
[3] Total feedstock reflects the maximum volume of RNG feedstocks available in Michigan, including all facilities and all biomass, and no restrictions are applied.
[4] Based on ICF analysis of data reported by the EIA regarding *Natural Gas Consumption by End Use*, available online at https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMI_A.htm. ICF excluded natural gas used in electric power generation in our consideration here because RNG is unlikely to displace natural gas used in electricity production given its higher cost.

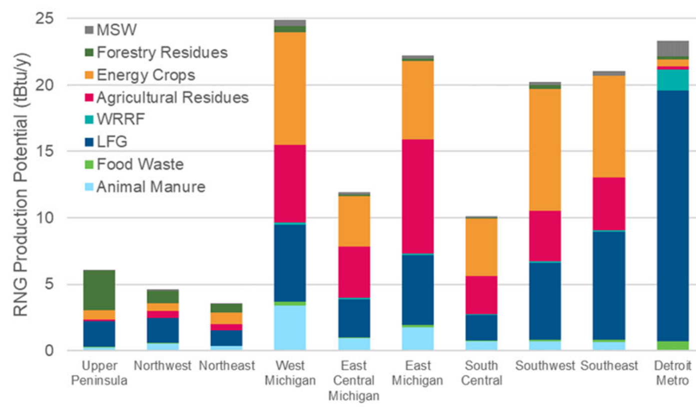
Achievable Scenario





Feasible Scenario





In the Achievable scenario, renewable natural gas from anaerobic digestion feedstocks represent the majority of overall production potential, with landfill gas and animal manure making up a large proportion out to 2050. Commercial deployment of the thermal gasification production technology after 2030 sees the increased deployment of feedstocks that utilize that technology, with energy crops and to a lesser degree agricultural residue and forestry residue contributing larger shares of overall potential. Consistent with the statewide timeseries, regions in Michigan with high feedstock potential from landfills and animal manure are the main sources of renewable natural gas production potential in the Achievable scenario. For example, the Detroit Metro has significant potential from landfills, while West Michigan has significant potential from animal manure.

Similar to the Achievable scenario, the Feasible scenario shows an early penetration of renewable natural gas from anaerobic digestion feedstocks, with an increased penetration of renewable natural gas from thermal gasification feedstocks taking place post-2030. With the higher deployment of energy crops and agricultural residues in the Feasible scenario, regions with large agricultural-based industries contribute a higher share to statewide renewable natural gas potential, such as West Michigan, East Michigan, Southeast and Southwest.

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.

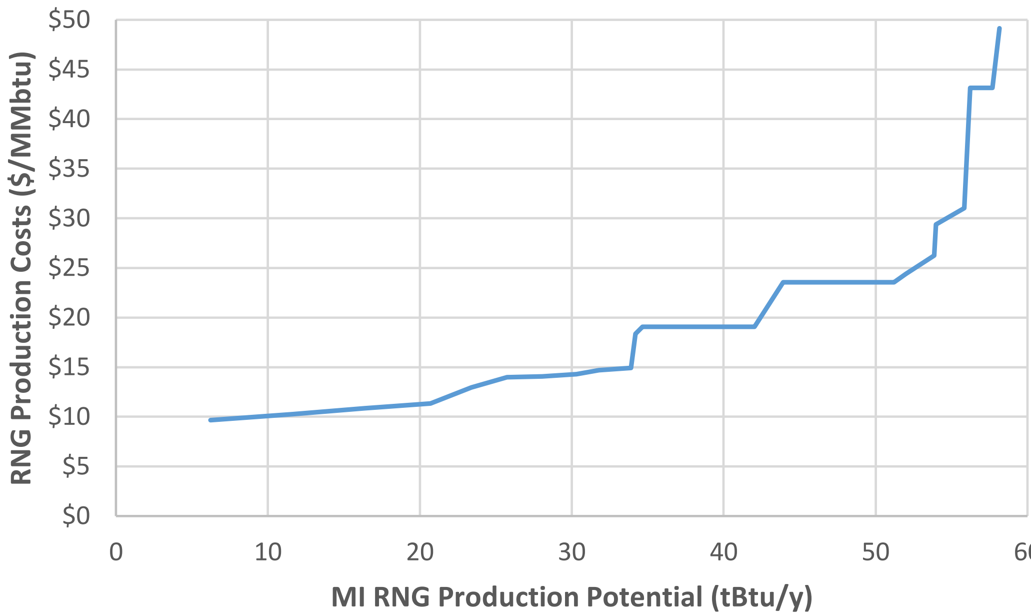
The table below summarizes the range of renewable natural gas production costs, broken down by feedstock. The range for each feedstock reflects variations in considerations associated with scale of individual renewable natural gas production facilities.

	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%.

The greenhouse gas emission reduction potential for renewable natural gas is best understood in the context of cost-effectiveness or in units of dollars per ton of emissions reduced. The reasoning is simple: absent cost reductions in renewable natural gas production technology, there will always be a potential “sticker shock” associated with renewable natural gas when framed using traditional metrics, like dollars per unit of energy (e.g., $/MMBtu). However, the cost-effectiveness of renewable natural gas deployment is a better metric to contextualize the opportunities for and barriers to broader renewable natural gas deployment as part of deep decarbonization considerations. For abatement cost estimates, renewable natural gas under $10/MMBtu is equivalent to about $130/tCO$_2$e, while renewable natural gas at $25/MMBtu has an estimated cost-effectiveness of about $400/tCO$_2$e.

Although ICF did not develop new analysis and modeling that estimates abatement costs for emission reduction measures beyond RNG, such as residential electrification and renewable hydrogen, this study does provide a first order comparison to other GHG abatement strategies. ICF analysis included renewable hydrogen blending, building electrification, electricity generation (including renewable electricity generation and nuclear electricity generation), and transportation electrification. The table below and the figure that follows summarizes the estimated abatement cost ranges for the four groupings of abatement measures.

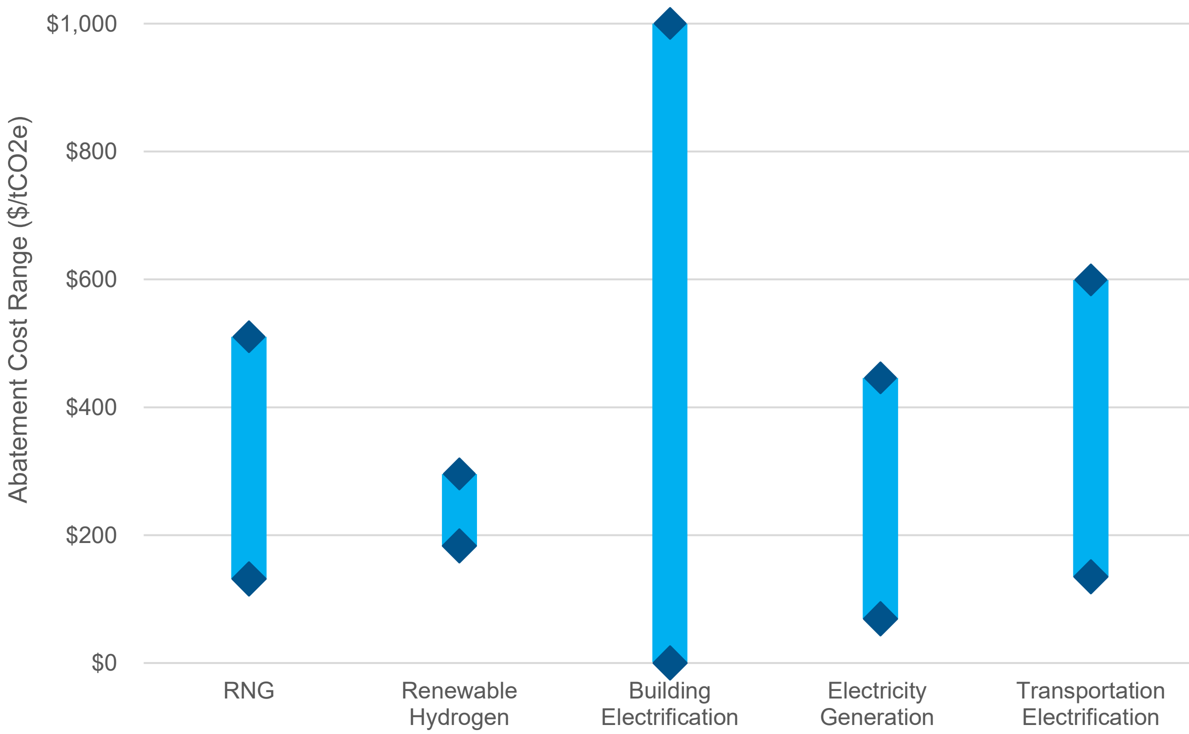
Summary of Abatement Costs for Emission Reduction Measures

Emission Reduction Measure	Abatement Cost ($/tCO$_2$e)	
	Low	High
Renewable Natural Gas (this study)	**$132**	**$510**
Renewable Hydrogen Blending Range	**$183**	**$296**
ICF Production Cost Estimates in 2050	$183	$296
Comparisons (Columbia Center on Global Energy Policy and US DOE)	$85	$791
Building Electrification Range	**$0**	**$1,000**
Pennsylvania Climate Action Plan[5]	-	$502
Energy Futures Initiative (EFI): California Deep Decarbonization[6]	$380	$540
University of Texas, Carnegie Mellon & University of Michigan[7]	$0	$1,000
Electricity Generation	**$69**	**$446**
E3: PJM 80-100% RPS 2050 (2020)[8]	$69	$220

[5] Pennsylvania Department of Environmental Protection, 2021. Pennsylvania Climate Action Plan, https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx
[6] EFI, 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://energyfuturesinitiative.org/efi-reports
[7] Thomas A Deetjen *et al* 2021 *Environ. Res. Lett.* 16 084024. US residential heat pumps: the private economic potential and its emissions, health, and grid impacts, https://iopscience.iop.org/article/10.1088/1748-9326/ac10dc#erlac10dcs6.
[8] E3, 2020. Least Cost Carbon Reduction Policies in PJM, https://www.ethree.com/least-cost-carbon-reduction-in-pjm/.

Emission Reduction Measure	Abatement Cost ($/t$CO_2$e)	
	Low	High
EFI & E3: New England Net Zero (2020)[9]	-	$446
Transportation Electrification	**$135**	**$599**
ICF Comparison of Medium and Heavy-Duty Truck Technologies10	$135	$400
E3: Deep Decarbonization in a High Renewables Future[11]	$359	$599

Full GHG Abatement Cost Ranges in 2050, Selected Measures ($/t$CO_2$e)



Across all the selected measures, there are broad ranges of abatement costs. These large ranges reflect the unique circumstances and factors involved with the practical and detailed implementation of each greenhouse gas emission reduction measure. Costs and emission reductions are greatly influenced by technology costs, efficiencies and availability, climate and geography, practical infrastructure constraints, whether local or system-wide, and the interconnected nature of emission reduction trends across the economy.

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[9] E3 and EFI, 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future, https://www.ethree.com/new-study-evaluates-deep-decarbonization-pathways-in-new-england/.
[10] ICF updated analysis of Comparison of Medium- and Heavy-Duty Technologies in California. Available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=236878.
[11] California Energy Commission, 2018. Deep Decarbonization in a High Renewables Future, https://www.energy.ca.gov/publications/2018/deep-decarbonization-high-renewables-future-updated-results-california-pathways.

These abatement cost ranges make direct comparisons across emission reduction measures challenging, particularly if there is a lack of rigorous analysis designed for specific circumstances, such as in the context of Michigan. However, the abatement cost estimates for renewable natural gas developed as part of this study can be used as a starting point to enable effective comparisons across emission reduction options. It is clear based on the abatement costs shown that renewable natural gas is potentially cost-competitive as an emission reduction approach, compared to other options relevant to the end-use of renewable natural gas.

Opportunities and Barriers for RNG Production in Michigan

There are multiple opportunities for renewable natural gas deployment to continue to be an effective GHG emission reduction measure in Michigan. The physical and environmental characteristics of renewable natural gas make for high development potential in Michigan, particularly in the context of ambitious long-term climate objectives. However, barriers and challenges remain, including limited capacity in current end-use markets, environmental impacts and social justice issues for some renewable natural gas feedstocks, and a limited policy structure. These barriers would need to be appropriately and adequately addressed through a robust, transparent and fair policy and regulatory environment that is not just limited to RNG, but for climate action more broadly.

The deployment of, and end-use demand for renewable natural gas is nascent but growing. With the ongoing expansion of the renewable natural gas market, there is increasing attention given to the opportunities and barriers associated with renewable natural gas production, delivery and end-use. In this section, ICF considers the highest-value opportunities and the corresponding challenges to realizing the potential of these opportunities in the renewable natural gas market. While the technical, market, regulatory, and environmental drivers for renewable natural gas are inextricably linked, we have distinguished between the key opportunities and challenges across these broad areas.

The table below summarizes the opportunities and barriers across the dimensions ICF considered in the analysis: technical, market, regulatory and policy, and environmental impacts.

RNG Deployment	Opportunities	Challenges
Technical	▪ RNG fulfills current definitions of a renewable resource in Michigan with carbon neutral characteristics using a combustion accounting framework for greenhouse gas emissions. Greenhouse gas emissions from RNG are lower than conventional natural gas across the board. The introduction of RNG has the potential to reduce greenhouse gas emissions significantly from the natural gas system. ▪ RNG utilizes the same existing infrastructure as conventional natural gas. When conditioned and upgraded to pipeline specifications, RNG can use the same extensive system of pipelines for the transmission and distribution of natural gas. Improved and continuous monitoring of potential harmful constituents from RNG production can decrease the technical risks of contamination in the pipeline.	▪ Feedstock location and accessibility will constrain RNG production potential. The location and availability of RNG feedstocks is mismatched with traditional demand centers for natural gas consumption. ▪ Competition for feedstocks will constrain RNG production potential. There is a diverse array of feedstocks available for RNG production yet accessing some of those feedstocks can be difficult or prohibitive. ▪ Gas quality and gas composition for RNG remains an engineering concern. There is no existing industrywide standard for RNG gas quality and gas composition, and with limited operational data, some concerns remain regarding RNG injection into a pipeline system. ▪ Seasonal variability in Michigan's natural gas systemwide demand may require the RNG production market to adapt. Like other regions with colder winters, Michigan's natural gas system sees a significant winter peak, largely driven by space heating demand.
Market	▪ RNG can deliver cost-effective greenhouse gas emission reductions for decarbonization. RNG can play an important role in helping to achieve decarbonization out to 2050. ▪ RNG helps maximize the utilization of evolving waste streams. The anaerobic digestion of biomass, including at landfills and water resource recovery facilities, helps maximize the use of waste. ▪ RNG markets are evolving to reflect utilities and corporations with climate and sustainability goals. There is increasing activity and interest in RNG outside of the transportation sector, and beyond jurisdictions where carbon constraining policies are influential. ▪ RNG helps give suppliers and consumers a viable decarbonization option in an evolving market and policy environment.	▪ Changes in existing programs may negatively impact the economic feasibility of existing Michigan-based RNG projects or limit the near-term growth potential for RNG projects in Michigan. ▪ Markets for RNG beyond transportation fuel are nascent. The long-term growth potential for RNG is dependent on transitioning to end uses other than transportation. ▪ RNG production and processing costs need to be reduced to improve cost-competitiveness. ▪ There is limited availability of qualified and experienced RNG developers to expand RNG production in the near-term future.

RNG Deployment	Opportunities	Challenges
		▪ The value of RNG is dependent on appropriately valuing environmental benefits compared to conventional alternatives. ▪ Interconnection costs for RNG suppliers and developers can be high.
Regulatory	▪ Conditioning and Interconnection Tariffs can help decrease the costs to developers of biogas conditioning and upgrading, and thereby providing more competitive pricing to consumers. ▪ Emergence of legislation and regulations for both mandatory and voluntary programs can help spur investment. ▪ Complementary policies could facilitate RNG feedstock collection (e.g., waste diversion and management), that help improve the accessibility of feedstocks while improving project development economics.	▪ The pathway for policies and incentives promoting RNG in market segments other than transportation is unclear and not uniform. ▪ The industry will face limits as technical and market constraints emerge in the near- to mid-term future, and the pathway for cost recovery may become less clear as incentives from out-of-state programs become less effective at promoting RNG deployment.
Environmental Impacts	▪ Investments in RNG production can yield positive environmental impacts upstream from the gas system and beyond greenhouse gas emissions. These include reducing or avoiding methane emissions from certain biomass feedstocks, helping to achieve waste management targets (e.g., waste diversion and waste utilization), supporting sustainable management practices in the agricultural and forestry sectors, and reducing the environmental impacts of concentrated animal feeding operations. ▪ If new policies are implemented to support RNG deployment in Michigan, they should ensure no back-sliding on other environmental indicators and avoid environmental injustices that have historically impacted at-risk communities.	▪ As with the natural gas industry more broadly, RNG development will face scrutiny as it relates to fugitive methane emissions, which occur along the entire natural gas supply chain—during processing, transmission, and distribution. ▪ There are a variety of environmental impacts of concentrated animal feeding operations, which represent one of the key feedstocks for RNG production in Michigan. At present, there is no clear indication that RNG policies or RNG production will impact industry trends related to concentrated animal feeding operations or contribute to the expansion of concentrated animal feeding operations in Michigan. However, it is important that there are controls put in place to ensure that RNG development would not lead to increased environmental harms or increase the risk of exposure to environmental injustices in at risk communities.

1. Introduction

Long-term environmental and energy policies for the state of Michigan are currently under development to meet aggressive long-term objectives to reduce greenhouse gas (GHG) emissions. Governor Gretchen Whitmer signed Executive Order 2020-182 and Executive Directive 2020-10 to create the MI Healthy Climate Plan. This plan establishes a pathway for Michigan to become carbon-neutral by 2050. To achieve these ambitious objectives, Michigan's policymakers, decision makers and stakeholders will need a solid evidence base for all available abatement options to make informed decisions on the most appropriate path forward. Renewable natural gas (RNG) has the potential to be a key contributor to this path to reach net zero carbon by 2050.

There is a key distinction to be made between the terms RNG and biogas. Typically, biogas refers to a mixture of gases, primarily consisting of methane (CH_4), carbon dioxide (CO_2), and hydrogen sulfide (H_2S) produced from the anaerobic digestion of renewable resources such as landfill waste, agricultural waste, animal manure, food waste, and other biomass. Biogas is captured to help avoid methane emissions, which are particularly harmful in the context of climate change because of methane's high global warming potential. When biogas is captured, it can either be a) flared to ensure the destruction of methane via combustion, emitting the less harmful carbon dioxide or b) used for beneficial energy end uses. Biogas has a methane content in the range of 45-75%. This methane content is adequate for biogas-to-electricity pathways. In most cases, biogas is used as fuel in combustion engines, which convert it to mechanical energy, powering an electric generator to produce electricity. The electric generator produces alternating current electricity, and the technology is well developed and widely available. The other beneficial use of the biogas is to condition it, which entails the removal of various constituents (like H2S, nitrogen, and oxygen), and upgrade it, which yields a high energy product that can be injected into a pipeline. This pathway yields RNG, which is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As a point of reference, Act 87 of Michigan Public Acts of 2021 uses the following definition for RNG:[12]

> *a biogas that has been processed or upgraded to be interchangeable with conventional natural gas and to meet pipeline quality standards or transportation fuel grade requirements.* [13]

Overview of Biogas in Michigan

Biogas already plays a role in Michigan's renewable energy landscape, most notably via the Renewable Portfolio Standard (RPS). Michigan enacted its RPS in 2008, referred to as the Clean, Renewable, and Efficient Energy Act (Public Act 295). The original RPS required the

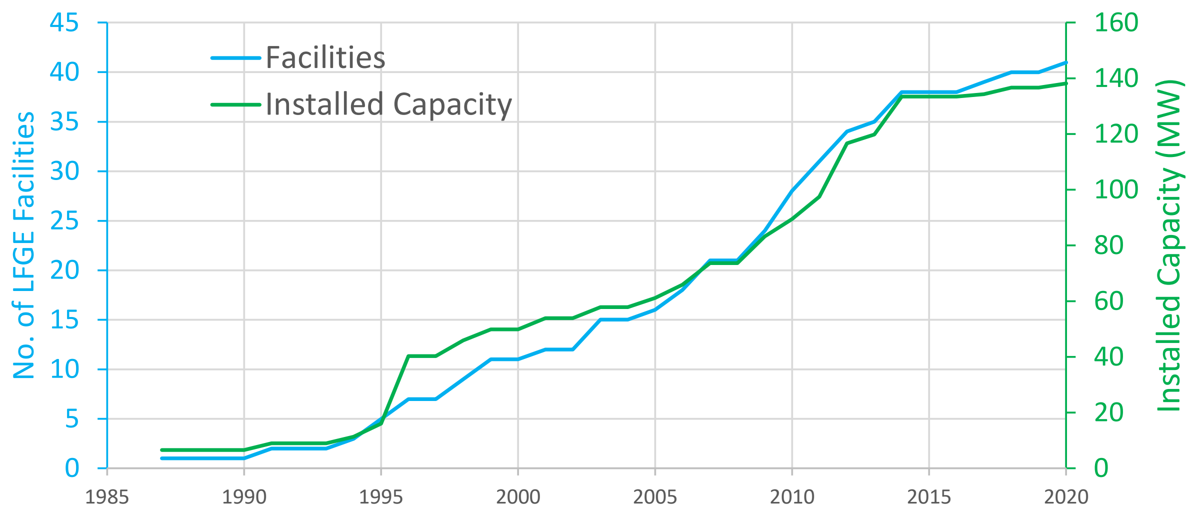
[12] Michigan Public Acts of 2021, Act No.87, https://www.legislature.mi.gov/documents/2021-2022/publicact/htm/2021-PA-0087.htm

[13] ICF notes that this is a useful definition but excludes RNG produced from the thermal gasification technology. The thermal gasification of sustainable biomass-based feedstocks delivers lower greenhouse gas emissions than geological natural gas and is interchangeable with natural gas and RNG. As a result, RNG from thermal gasification is included as a resource in this study.

state's investor-owned utilities (IOUs) and other electricity suppliers (e.g., municipally owned electric utilities, MOUs) to generate 10% of their retail electricity sales from renewable energy resources by 2015. This was subsequently increased to 15% by 2021 when Public Act 342 of 2016 was signed in December 2016.[14] The RPS identifies landfill gas, municipal solid waste (MSW), and biomass as eligible technologies, noting that biomass "means any organic matter that is not derived from fossil fuels, that can be converted to usable fuel for the production of energy, and that replenishes over a human, not a geological, time frame."[15] According to the most recent information available from the Public Service Commission (PSC), Michigan electric providers retired nearly 13 million renewable energy certificates (RECs) in 2019, equivalent to roughly 13% of retail sales. Of the 13 million RECs, landfill gas, MSW, and biomass represented 9%, 4%, and 13%, respectively.

Based on ICF's research, it appears that Michigan's first biogas-to-electricity project was deployed at the Riverview Land Preserve, a landfill in Wayne County, in 1987 as a 6.6 MW system using a gas turbine. This landfill gas to electricity (LFGE) project is common in Michigan; as of 2020, for instance, 41 of these projects have been deployed across the state with a cumulative installed capacity of 138.2 MW (see graph below). Michigan's expansion of LFGE projects continued in earnest, with the most consistent growth between 1995 and 2013.

Figure 1-1. LFGE facilities and installed capacity (MW) deployed in Michigan



Michigan benefits from a variety of investments that have been made to capture biogas for beneficial use. In addition to the 41 landfills that have installed more than 135 MW of electricity generation, 5 landfills in Michigan have so-called direct use applications, which uses biogas in boilers or other direct thermal uses.

[14] Michigan's two largest investor-owned utilities, DTE Electric and Consumers Energy, have additional obligations beyond those of other utilities.

[15] Biomass includes agricultural crops and crop wastes, short-rotation energy crops, herbaceous plants, trees and wood (with sustainable management practices in place), paper and pulp products, precommercial wood thinning waste, brush or yard waste, wood wastes and residues from the processing of wood products or paper; animal wastes, wastewater sludge or sewage; aquatic plants, food production and processing waste, and organic by-products from the production of biofuels.

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.

[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.

Stakeholder Engagement

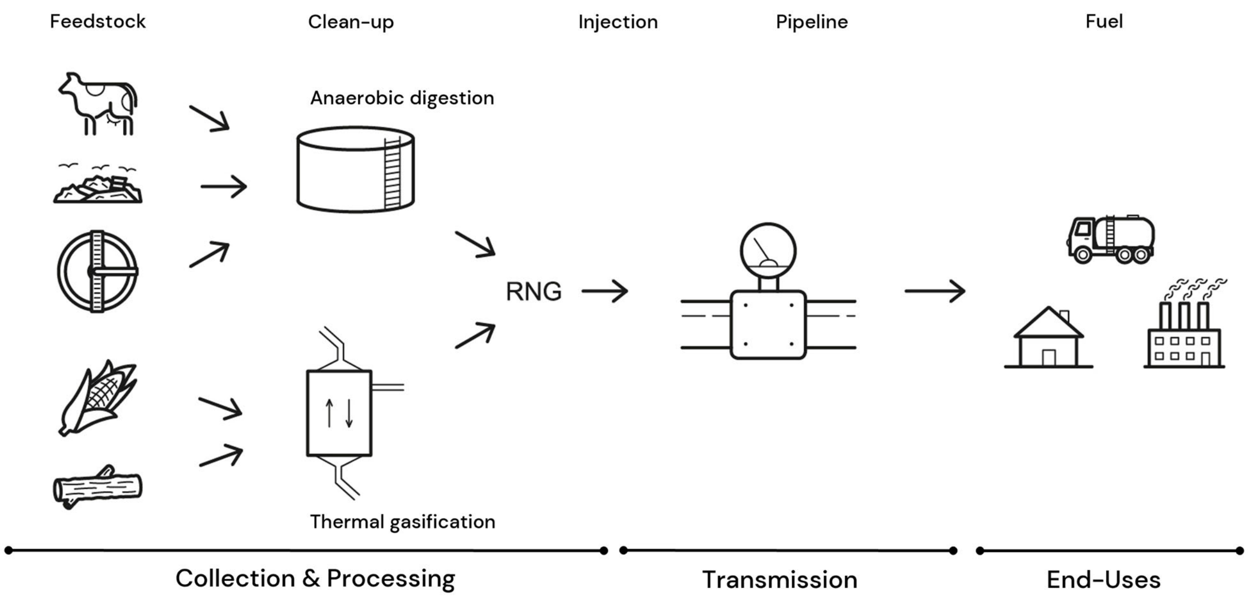
ICF worked in partnership with the Michigan Public Service Commission (MPSC) to conduct stakeholder engagement as part of this study. There were multiple opportunities for stakeholder engagement throughout this study. ICF and MPSC appreciate and value stakeholder efforts and input. All information submitted during the stakeholder engagement process was considered during the completion of this study. ICF and MPSC conducted the following stakeholder engagement in the process of finalizing this study:

- MPSC developed the Renewable Natural Gas Study Workgroup page on the MPSC website and used this site to post and update information relating to the study which includes:
    - Documents and resources
    - Actions to date (including stakeholder comments received)
    - Next steps
    - Information on stakeholder meetings (including agenda, presentations, and a recording of each)
- MPSC created a Renewable Gas Study Workgroup Mailing List that interested stakeholders could sign up for to receive email updates about key dates and information.
- MPSC posted an outline of the proposed study in December 2021 for stakeholder review.
- MPSC hosted and ICF led or participated in three public meetings. In the first public meeting in January 2022, ICF reviewed the scope of work and the key elements of the strategy to complete that scope of work. At the second public meeting in April 2022, ICF reviewed the assumptions and methodology that were used to develop the study assumptions. A background document was provided in advance of the meeting and posted publicly. Stakeholders also presented during the second meeting. In the third and final public meeting in June 2022, ICF reviewed the key findings of the study.
- In March 2022, MPSC issued a request for input from stakeholders concerning existing GHG emission reduction studies, especially those that quantify GHG abatement costs of comparable technologies. Ultimately, a list of resources received was posted online and each of these were considered for incorporation into the report (see Section 7).
- MPSC posted the draft version of this study for review on June 8, which allowed three weeks for review in advance of the June 29 meeting. ICF responded to subsequent data requests issued by stakeholders in July 2022, and MPSC extended the deadline for submission of public comments to August 3, 2022.

2. RNG Production

RNG is produced over the series of steps shown in Figure 2-1 including collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression, and injection into the pipeline.

Figure 2-1. RNG Production Process via Anaerobic Digestion and Thermal Gasification



In this study ICF considers two production technologies: anaerobic digestion and thermal gasification.

Anaerobic Digestion

The most common way to produce RNG today is via anaerobic digestion (AD), whereby microorganisms break down organic material in an environment without oxygen. The four key processes in anaerobic digestion are hydrolysis, acidogenesis, acetogenesis, and methanogenesis. Hydrolysis is the process whereby longer-chain organic polymers are broken down into shorter-chain molecules like sugars, amino acids, and fatty acids that are available to other bacteria. Acidogenesis is the biological fermentation of the remaining components by bacteria, yielding volatile fatty acids, ammonia, carbon dioxide, hydrogen sulfide, and other byproducts. Acetogenesis of the remaining simple molecules yields acetic acid, carbon dioxide, and hydrogen. Lastly, methanogens use the intermediate products from hydrolysis, acidogenesis, and acetogenesis to produce methane, carbon dioxide, and water, where the majority of the biogas is emitted from anaerobic digestion systems.

The process for RNG production generally takes place in a controlled environment, referred to as a digester or reactor, including landfill gas facilities. When organic waste, biosolids, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide. The biogas requires capture and then subsequent conditioning and upgrade before pipeline injection. The conditioning and upgrading helps to remove any contaminants and other trace constituents, including siloxanes, sulfides and nitrogen, that cannot be injected into common carrier pipelines, and increases the heating value of the gas for injection.

Thermal Gasification

Biomass-like agricultural residues, forestry and forest produce residues, and energy crops have high energy content and are ideal candidates for thermal gasification. The thermal gasification of biomass to produce RNG occurs over a series of steps:

- Feedstock pre-processing in preparation for thermal gasification (not in all cases).
- Gasification, which generates synthetic gas (syngas), consisting of hydrogen and carbon monoxide (CO).
- Filtration and purification, where the syngas is further upgraded by filtration to remove remaining excess dust generated during gasification, and other purification processes to remove potential contaminants like hydrogen sulfide, and carbon dioxide.
- Methanation, where the upgraded syngas is converted to methane and dried prior to pipeline injection.

Biomass gasification technology is at an early stage of commercialization, with the gasification and purification steps presenting challenges. The gasification process typically yields a residual tar, which can foul downstream equipment. Furthermore, the presence of tar effectively precludes the use of a commercialized methanation unit. The high cost of conditioning the syngas in the presence of these tars has limited the potential for thermal gasification of biomass. For instance, in 1998, Tom Reed[20] concluded that after "two decades" of experience in biomass gasification, "'tars' can be considered the Achilles heel of biomass gasification."

Over the last several years, however, a few commercialized technologies have been deployed to increase syngas quantity and prevent the fouling of other equipment by removing the residual tar before methanation. There are a handful of technology providers in this space, including Haldor Topsoe's tar-reforming catalyst. Frontline Bioenergy takes a slightly different approach and has patented a process producing tar-free syngas (referred to as TarFreeGas™).

More recently, a handful of thermal gasification projects are in the late stages of planning and development in North America. For example, REN is proposing to build a modular thermal gasification facility in British Columbia using wood waste to produce pipeline-quality RNG for the local natural gas utility, FortisBC.[21] Sierra Energy's thermal gasification and biorefinery facility in Nevada produces RNG and liquid fuels using municipal solid waste as a feedstock.[22] West Biofuels have a number of demonstration and research projects using biomass to produce RNG, as well as commercialized thermal gasification facilities producing other renewable fuels.[23] Further afield there are demonstration and early-commercialization thermal gasification projects across Europe, including Sweden, France and Austria.[24]

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[20] NREL, Biomass Gasifier "Tars": Their Nature, Formation, and Conversion, November 1998, NREL/TP-570-25357. Available online at https://www.nrel.gov/docs/fy99osti/25357.pdf.
[21] FortisBC, 2020. Filing of a Biomethane Purchase Agreement between FEI and REN Energy International Corp, https://www.bcuc.com/Documents/Proceedings/2020/DOC_57461_B-1-FEI-REN-Sec-71-BPA-Application-Confidential-Redacted.pdf.
[22] Sierra Energy, 2020. https://sierraenergy.com/projects/fort-hunter-liggett/
[23] West Biofuels, 2020. http://www.westbiofuels.com/projects?filter=research
[24] Thunman, H. et al, 2018. Advanced biofuel production via gasification - lessons learned from 200 years man-years of research activity with Chalmers' research gasifier and the GoBiGas demonstration plant. Energy Science & Engineering, 29.

ICF notes that biomass, particularly agricultural residues, are often added to anaerobic digesters to increase gas production (by improving carbon-to-nitrogen ratios, especially in animal manure digesters). It is conceivable that some of the feedstocks considered here could be used in anaerobic digesters. For simplicity, ICF did not consider any multi-feedstock applications in our assessment; however, it is important to recognize that the RNG production market will continue to include mixed feedstock processing in a manner that is cost-effective.

3. RNG Feedstock Inventory

RNG Feedstocks

RNG can be produced from a variety of renewable feedstocks, as described in the table below.

Table 3-1. RNG Feedstock Types

Feedstock for RNG		Description
Anaerobic Digestion	Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
	Food waste	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
	Landfill gas (LFG)	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
	Water resource recovery facilities (WRRF)	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.
Thermal Gasification	Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
	Energy crops	Inclusive of perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production.
	Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
	Municipal solid waste (MSW)	The biogenic fraction of waste that would be landfilled after diversion of other waste products (e.g., food waste or other organics), including paper and paperboard and yard trimmings.

While this resource assessment applies these biomass feedstock categories as a framework to assess RNG potential, ICF notes that these categories are not necessarily discrete, and that RNG production facilities can utilize multiple feedstock and waste streams. For example, food waste is often added to anaerobic digester systems at WRRFs to augment biomass and overall gas production. In addition, current wastes streams can potentially be diverted from one feedstock category to another, such as MSW or food waste that is currently landfilled being diverted away from landfills and LFG facilities.

To avoid the potential double counting of biomass, LFG potential is derived from current waste-in-place estimates and does not include any projections of waste accumulation or the introduction of waste diversion. This likely underestimates the potential of RNG from LFG, but additional biomass that could potentially be used to produce RNG is captured in other feedstock categories, such as MSW and food waste.

Inventory Methodology

ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks. The table below summarizes some of the resources that ICF drew from to complete our resource assessment, broken down by RNG feedstock:

Table 3-2. List of Data Sources for RNG Feedstock Inventory

Feedstock for RNG	Potential Resources for Assessment
Animal manure	▪ U.S. Environmental Protection Agency (EPA) AgStar Project Database ▪ U.S. Department of Agriculture (USDA) Census of Agriculture ▪ Michigan Department of Environment, Great Lakes and Energy Concentrated Animal Feeding Operation Database
Food waste	▪ U.S. Department of Energy (DOE) 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework (KDF)
LFG	▪ U.S. EPA Landfill Methane Outreach Program ▪ Environmental Research & Education Foundation (EREF) ▪ Michigan Department of Environment, Great Lakes and Energy Concentrated Solid Waste Facilities Database
WRRFs	▪ U.S. EPA Clean Watersheds Needs Survey (CWNS) ▪ Water Environment Federation
Agricultural residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Energy crops	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
MSW	▪ U.S. DOE 2016 Billion Ton Report ▪ Waste Business Journal

This RNG feedstock inventory does not take into account 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 3.

Consistent across all feedstocks, ICF estimates RNG potential at the county level across Michigan. Where possible, ICF includes facility-level information for relevant feedstocks, notably landfill gas facilities and WRRFs. While the underlying RNG data is collected for all 83 counties in Michigan, in this report we aggregate and present the data based on Michigan's ten prosperity regions,[25] shown in Figure 3-1 below.

[25] https://www.michigan.gov/images/mshda/MI-prosperity-regions-map-LG_616814_7.png

Figure 3-1. Michigan Prosperity Regions

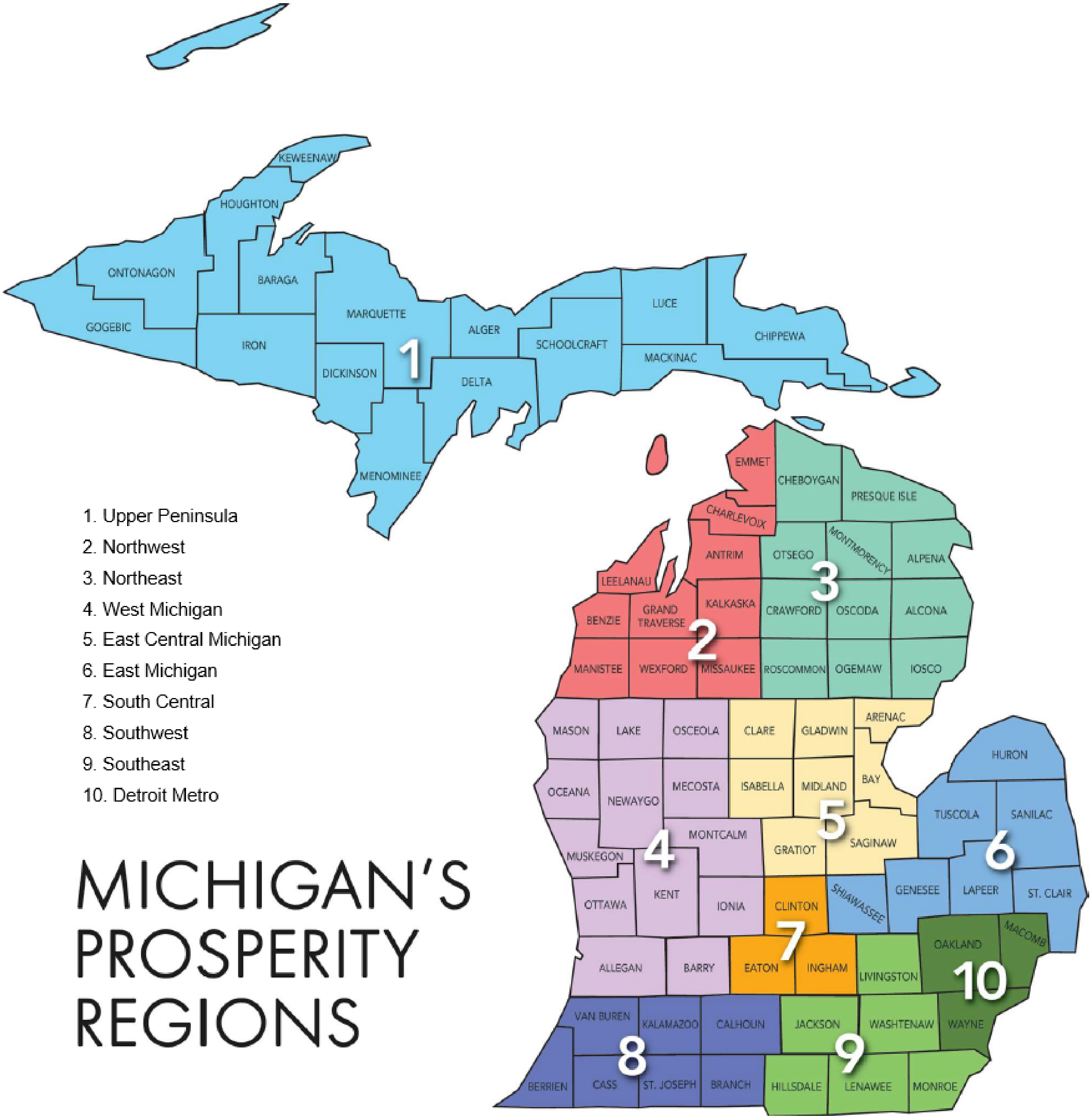
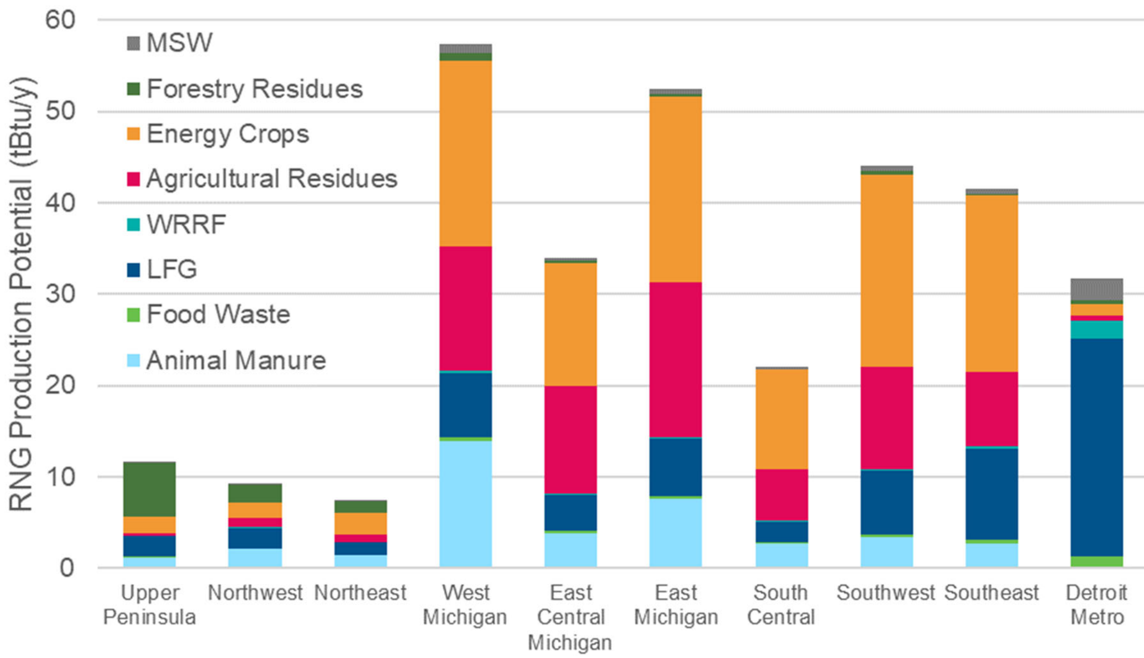


Figure 3-2 below shows the maximum RNG production potential broken out by region. Regions with large and concentrated land sector-based industries, such as West Michigan and East Michigan, have the greatest RNG production potential, reflecting significant volumes of feedstocks including animal manure, agricultural residue, and energy crops. Regions with large populations, such as Southeast and Detroit Metro, have the highest potential from population-based waste streams, including landfills, wastewater and food waste.

Figure 3-2. Maximum RNG Production Potential by Region (tBtu/y)



RNG: Anaerobic Digestion of Biogenic or Renewable Resources

Animal Manure

Animal manure as an RNG feedstock is produced from the manure generated by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses. The U.S. EPA lists a variety of benefits associated with the anaerobic digestion of animal manure at farms as an alternative to traditional manure management systems, including but not limited to:[26]

- Diversifying farm revenue: the biogas produced from the digesters has the highest potential value. Digesters can also provide revenue streams via “tipping fees” from non-farm organic waste streams that are diverted to the digesters, organic nutrients from the digestion of animal manure, and displacement of animal bedding or peat moss by using digested solids.
- Conservation of agricultural land: digesters can help to improve soil health by converting the nutrients in manure to a more accessible form for plants to use and help protect the local water resources by reducing nutrient run-off and destroying pathogens.

[26] More information available online at https://www.epa.gov/agstar/benefits-anaerobic-digestion.

- Promoting energy independence: the RNG produced can reduce on-farm energy needs or provide energy via pipeline injection for use in other applications, thereby displacing conventional natural gas.
- Bolstering farm-community relationships: digesters help to reduce odors from livestock manure, improve growth prospects by minimizing potential negative impacts of farm operations on local communities, and help forge connections between farmers and the local community through environmental and energy stewardship.

The main components of anaerobic digestion of manure include manure collection, the digester, effluent storage (e.g., a tank or lagoon), and gas handling equipment. There are a variety of livestock manure processing systems that are employed at farms today, including plug-flow or mixed plug-flow digesters, complete-mixed digesters, covered lagoons, fixed-film digesters, sequencing-batch reactors, and induced-blanked digesters. Most dairy manure projects today, including those in Michigan, use the plug-flow or mixed plug-flow digesters.

ICF considered animal manure from a variety of animal populations, including beef and dairy cows, broiler chickens, layer chickens, turkeys, and swine. Animal populations were derived from the United States Department of Agriculture's (USDA) National Agricultural Statistics Service. ICF used information provided from the most recent census year (2017) and extracted total animal populations on a county and state level.[27] Based on this information, ICF identified animal populations for Michigan by county.

ICF developed the maximum RNG potential using animal manure production and the energy content of dried manure taken from a California Energy Commission report prepared by the California Biomass Collaborative.[28] These inputs are summarized in Table 3-3 below, with the formula and an example calculation of a 10,000-head dairy farm included for reference:

$$number\ of\ livestock\ \times volatile\ solids\ \times heating\ value\ = RNG\ production\ potential$$

$$10{,}000\ head\ \times 3{,}020\ \frac{kg\ (dry)}{head} \times 16{,}111\ \frac{Btu}{kg\ (dry)} \times \frac{1}{1.0^6} = 486{,}491\ MMBtu$$

[27] USDA, 2017. 2017 Census of Agriculture, https://www.nass.usda.gov/AgCensus/index.php
[28] Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. Available online here.

Table 3-3. Key Parameters for Animal Manure Resource RNG Potential

Animal Type	Volatile Solids (kg/head/year)	Higher Heating Value (HHV) (Btu/kg, dry basis)
Dairy	3,020	16,111
Beef: - Cattle - Other	 1,674 750	 16,345 16,345
Swine	149	15,077
Poultry: - Layer Chickens - Broiler Chickens - Turkeys	 8.3 9.1 25.0	 14,689 15,077 14,830
Sheep & Goats	242	9,362

The U.S. EPA AgStar database indicates that there are eight operational anaerobic digesters at farms in Michigan, with another four under construction.[29]

The animal manure inventory does not identify specific facilities or locations where RNG will likely be produced. However, concentrated animal feeding operations (CAFOs) provide an indication of where RNG from animal manure could be produced. For example, of the eight operational anaerobic digesters at farms in Michigan, six are also licensed CAFOs.

The existing accumulation of animal manure at CAFOs located near pipeline infrastructure could conceivably increase the productive potential of animal manure as an RNG feedstock. The Michigan Department of Environment, Great Lakes and Energy (EGLE) reports that there are 290 CAFOs in Michigan.[30]

The table below shows the volume of animal feedstock available and maximum RNG potential in Michigan and for each prosperity region. Note that the maximum RNG potential does not take into account the numerous limiting factors that would constrain the volume of RNG that could be produced from animal manure. The significant animal head count figure for the West Michigan region reflects large poultry farms in counties such as Allegan, Ionia and Ottawa, including the operations of Herbuck's Poultry Ranch, a leading producer in the state.

[29] U.S. EPA, 2020. AgStar Database, https://www.epa.gov/agstar/livestock-anaerobic-digester-database.
[30] Michigan EGLE, 2021. CAFO Database, https://www.michigan.gov/egle/0,9429,7-135-3313_71618_3682_3713-96774--,00.html.

Table 3-4. Animal Manure Resource RNG Potential

Region	Animal Head Count (millions)	Maximum RNG Potential (tBtu)
Region 1 – Upper Peninsula	0.1	1.2
Region 2 – Northwest	0.1	2.1
Region 3 – Northeast	0.1	1.4
Region 4 – West Michigan	23.1	13.9
Region 5 – East Central Michigan	0.5	3.9
Region 6 – East Michigan	0.4	7.6
Region 7 – South Central	0.1	2.7
Region 8 – Southwest	1.7	3.4
Region 9 – Southeast	0.2	2.8
Region 10 – Detroit Metro	0.0	0.1
Michigan Total	**26.5**	**39.0**

Food Waste

Food waste includes biomass sources from commercial, industrial and institutional facilities, including from food processors and manufacturers, grocery stores, cafeterias, and restaurants. Food waste from residential sources is not reflected in this analysis, but could be an additional resource for food waste biomass with the implementation of effective waste diversion policies.

Food waste is a significant component of MSW—accounting for about 15% of MSW streams. More than 75% of food waste is landfilled. Food waste can be diverted from landfills to a composting or processing facility where it can be treated in an anaerobic digester. ICF limited consideration to the potential for utilizing the food waste that would otherwise be landfilled as a feedstock for RNG production via AD, thereby excluding the 25% of food waste that is recycled or directed to waste-to-energy facilities. In addition, food waste that is potentially diverted from landfills in the future is not included in the landfill gas analysis (outlined in more detail below), thereby avoiding any issues around double counting of biomass from food waste.

As food waste is generated from population centers and typically diverted at waste transfer stations rather than delivered to landfills, it is challenging to identify specific facilities or projects that will generate RNG from food waste. However, food waste can potentially utilize existing or future AD systems at LFG and WRRF facilities.

ICF extracted county-level information from the U.S. DOE's Bioenergy Knowledge Discovery Framework (KDF), which includes information collected as part of U.S. DOE's Billion Ton Report (updated in 2016). The Bioenergy KDF includes food waste at tipping fee price points ranging from $70/ton to $100/ton. ICF assumed a high heating value of 12.04 MMBtu/ton (dry). Note that the values from the Bioenergy KDF are reported in dry tons, so the moisture content of the food waste has already been accounted for in the DOE's resource assessment.

The table below shows the maximum volume of food waste available, and the maximum RNG potential for the ten prosperity regions, and the state as a whole, noting that no limiting factors were applied to the RNG potential.

Table 3-5. Maximum Food Waste Potential in 2040

Region	Maximum Production (dry tons)	Maximum RNG Potential (tBtu)
Region 1 – Upper Peninsula	8,690	0.1
Region 2 – Northwest	6,755	0.1
Region 3 – Northeast	5,205	0.1
Region 4 – West Michigan	38,790	0.5
Region 5 – East Central Michigan	14,505	0.2
Region 6 – East Michigan	21,898	0.3
Region 7 – South Central	11,807	0.1
Region 8 – Southwest	19,678	0.2
Region 9 – Southeast	25,064	0.3
Region 10 – Detroit Metro	97,687	1.2
Michigan Total	**250,079**	**3.0**

Landfill Gas

The Resource Conservation and Recovery Act of 1976 (RCRA, 1976) sets criteria under which landfills can accept municipal solid waste and nonhazardous industrial solid waste. Furthermore, the RCRA prohibits open dumping of waste, and hazardous waste is managed from the time of its creation to the time of its disposal. Landfill gas (LFG) is captured from the anaerobic digestion of biogenic waste in landfills and produces a mix of gases, including methane, with a methane content generally ranging 45%–60%. The landfill itself acts as the digester tank—a closed volume that becomes devoid of oxygen over time, leading to favorable conditions for certain micro-organisms to break down biogenic materials.

The composition of the LFG is dependent on the materials in the landfill, and other factors, but is typically made up of methane, carbon dioxide (CO_2), nitrogen (N_2), hydrogen, carbon monoxide (CO), oxygen (O_2), sulfides (e.g., hydrogen sulfide or H_2S), ammonia, and trace elements like amines, sulfurous compounds, and siloxanes. RNG production from LFG requires advanced treatment and upgrading of the biogas via removal of CO_2, H_2S, siloxanes, N_2, and O_2 to achieve a high-energy (Btu) content gas for pipeline injection. The table below summarizes landfill gas constituents, the typical concentration ranges in LFG, and commonly deployed upgrading technologies in use today.

Table 3-6. Landfill Gas Constituents and Corresponding Upgrading Technologies

LFG Constituent	Typical Concentration Range	Upgrading Technology for Removal
Carbon dioxide, CO_2	40% – 60%	▪ High-selectivity membrane separation ▪ Pressure swing adsorption (PSA) systems ▪ Water scrubbing systems ▪ Amine scrubbing systems
Hydrogen sulfide, H_2S	0 – 1%	▪ Solid chemical scavenging ▪ Liquid chemical scavenging ▪ Solvent adsorption ▪ Chemical oxidation-reduction
Siloxanes	<0.1%	▪ Non-regenerative adsorption ▪ Regenerative adsorption
Nitrogen, N_2 Oxygen, O_2	2% – 5% 0.1% – 1%	▪ PSA systems ▪ Catalytic removal (O_2 only)

To estimate the feedstock potential of LFG, ICF used outputs from the LandGEM model, which is an automated tool with a Microsoft Excel interface developed by the U.S. EPA to estimate the emissions rates for landfill gas and methane based on user inputs including waste-in-place (WIP), facility location and climate conditions, and waste received per year. The estimated LFG output was estimated on a facility-by-facility basis. About 1,150 facilities report methane content; for the facilities for which no data were reported, ICF assumed the median methane content of 49.6%.

To develop the RNG potential from LFG, ICF extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. EPA, which included more than 2,000 landfills, with 60 in Michigan and included in the inventory. The U.S. EPA's LMOP database shows that there are 35 landfills in Michigan which have operational LFG-to-energy projects.[31] ICF cross-checked the U.S. EPA LMOP database with Michigan EGLE Department's solid waste facilities database and confirmed that the list of facilities was consistent across the two datasets.[32]

The U.S. EPA currently estimates that there are 15 candidate landfills in Michigan that could capture LFG for use as energy—the U.S. EPA characterizes candidate landfills as those that are accepting waste or have been closed for five years or less, have at least one million tons of WIP, and do not have operational, under-construction, or planned projects. Candidate landfills can also be designated based on actual interest by the site.

[31] Some landfills have multiple landfill-to-gas energy projects, with 41 projects in total across the 35 landfills.
[32] Michigan EGLE Department Solid Waste Facilities, 2021. https://www.michigan.gov/egle/0,9429,7-135-3312_4123-9894--,00.html

Table 3-7. Michigan Landfills by Region[33]

Region	Landfills	Landfill-to-Energy Projects	EPA Candidate Landfills
Region 1 – Upper Peninsula	7	-	6
Region 2 – Northwest	4	1	2
Region 3 – Northeast	3	1	2
Region 4 – West Michigan	8	5	1
Region 5 – East Central Michigan	6	5	-
Region 6 – East Michigan	8	5	2
Region 7 – South Central	2	2	-
Region 8 – Southwest	6	4	1
Region 9 – Southeast	6	4	1
Region 10 – Detroit Metro	10	8	-
Michigan Total	**60**	**35**	**15**

There are 47 large landfills in Michigan that have more than one million tons of WIP, with the largest 30 shown in the table below. Due to the minimal and declining methane production of waste after 25 years in landfills, ICF typically only considers RNG potential from landfills that are either currently open or were closed post-2000.

Of the 47 large landfills, nine do not have landfill gas collection systems in place and are identified by the U.S. EPA as candidate landfills. The remaining 38 landfills all have existing gas collection systems, with 31 having LFG-to-energy projects in place. LFG-to-energy projects typically use unprocessed biogas (the feedstock for RNG) to power reciprocating engines to produce electricity, or fuel cogeneration or boiler systems.

Table 3-8. Large Landfills in Michigan

Landfill	County	LFG Collection Project Type	RNG Potential (MMBtu/year)
Arbor Hills Landfill Inc.	Washtenaw	Electricity (combined cycle)	6,217,557
Woodland Meadows Landfill	Wayne	RNG for pipeline injection	5,380,443
Carleton Farms Landfill	Wayne	Electricity (reciprocating engine)	4,760,141
Pine Tree Acres LF Inc.	Macomb	Electricity (reciprocating engine)	4,343,810
Ottawa County Farms LF	Ottawa	Electricity (reciprocating engine)	2,688,298
Sauk Trail Hills Landfill	Wayne	RNG for pipeline injection	2,341,448
Forest Lawn Landfill	Berrien	Flared (candidate landfill)	2,324,167
Riverview Land Preserve	Wayne	Electricity & RNG	2,260,223

[33] Based on data from the LMOP at the U.S. EPA (updated March 2022).

Landfill	County	LFG Collection Project Type	RNG Potential (MMBtu/year)
Vienna Junction Landfill	Monroe	Boiler	2,102,949
Oakland Heights Landfill	Oakland	Boiler	1,773,192
Brent Run Landfill	Genesee	Electricity (reciprocating engine)	1,697,294
C&C Landfill	Calhoun	Electricity (reciprocating engine)	1,584,403
Citizens Disposal Landfill	Genesee	Electricity (cogeneration)	1,520,132
Westside Recycling Facility	St. Joseph	RNG for pipeline injection	1,401,147
Granger Wood Street LF	Clinton	RNG for pipeline injection	1,396,661
Autumn Hills Facility	Ottawa	Electricity (reciprocating engine)	1,392,323
Eagle Valley RDF	Oakland	Electricity (reciprocating engine)	1,329,123
People's Landfill, Inc.	Saginaw	Electricity (reciprocating engine)	1,187,972
Venice Park Facility	Shiawassee	Electricity (reciprocating engine)	1,155,545
City of Midland Sanitary LF	Midland	Electricity (cogeneration)	1,028,101
Smiths Creek Landfill	St. Clair	Electricity (reciprocating engine)	992,838
Kent County South Kent LF	Kent	Electricity (reciprocating engine)	915,719
Central Sanitary LF	Montcalm	Electricity (reciprocating engine)	894,786
Granger Grand River LF	Clinton	Electricity (reciprocating engine)	887,075
Adrian Landfill	Lenawee	Electricity (reciprocating engine)	861,493
Orchard Hill SLF	Berrien	Electricity (reciprocating engine)	741,651
Southeast Berrien County LF	Berrien	Electricity (reciprocating engine)	724,194
Manistee County LF	Manistee	Flared (candidate landfill)	667,793
Waters Landfill	Crawford	Boiler	659,205
Menominee Landfill	Menominee	No collection (candidate landfill)	658,622
Wexford County Landfill	Wexford	Flared (candidate landfill)	566,898
Whitefeather Landfill	Bay	Electricity (reciprocating engine)	553,972
Glen's Sanitary Landfill Inc.	Leelanau	Boiler	550,732
Northern Oaks Facility	Clare	Electricity (reciprocating engine)	548,748
Cedar Ridge Facility	Charlevoix	No collection	504,560
Muskegon County SWF	Muskegon	Boiler	469,621
Tri-City RDF	Sanilac	Flared (candidate landfill)	447,593
Hastings Sanitary Landfill	Barry	Flared (candidate landfill)	435,283
K&W LF	Ontonagon	No collection (candidate landfill)	382,241
Montmorency-Oscoda-Alp. LF	Montmorency	No collection (candidate landfill)	376,232
Huron Landfill	Huron	No collection (candidate landfill)	358,248
McGill Road Landfill	Jackson	Flared (candidate landfill)	346,746
Dafter Sanitary Landfill Inc	Chippewa	No collection (candidate landfill)	330,171

Landfill	County	LFG Collection Project Type	RNG Potential (MMBtu/year)
Elk Run Sanitary Landfill	Presque Isle	No collection (candidate landfill)	317,718
Delta County Landfill	Delta	Flared (candidate landfill)	309,862
Wood Island Waste LF	Alger	No collection (candidate landfill)	309,174
Marquette County SWL	Marquette	No collection (candidate landfill)	272,805

The table below shows overall maximum RNG potential from LFG facilities for Michigan, as well as the potential at landfills that do not have landfill-to-energy projects. ICF notes that the RNG potential from unutilized landfills in Michigan is likely an underestimation, as while the majority of LFG is already utilized in existing LFG-to-energy projects, many of the systems operate at maximum capacity, with excess gas flared. In addition, there is a growing trend for landfill operators to convert existing energy projects to produce RNG, driven by regulatory incentives as well as a higher-value end product.

Table 3-9. RNG Potential from Landfills by Region

Region	Landfills	Unutilized LFG Potential[34] (tBtu/y)	Maximum RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	7	2.3	2.3
Region 2 – Northwest	4	1.7	2.3
Region 3 – Northeast	3	0.7	1.4
Region 4 – West Michigan	8	0.8	7.2
Region 5 – East Central Michigan	6	0.6	4.0
Region 6 – East Michigan	8	1.1	6.4
Region 7 – South Central	2	-	2.3
Region 8 – Southwest	6	2.7	7.1
Region 9 – Southeast	6	0.6	10.3
Region 10 – Detroit Metro	10	2.3	24.6
Michigan Total	**60**	**12.7**	**67.8**

Water Resource Recovery Facilities

Wastewater is created from residences and commercial or industrial facilities, and it consists primarily of waste liquids and solids from household water usage, from commercial water usage, or from industrial processes. Depending on the architecture of the sewer system and local regulation, it may also contain storm water from roofs, streets, or other runoff areas. The contents of the wastewater may include anything which is expelled (legally or not) from a household and enters the drains. If storm water is included in the wastewater sewer flow, it may

[34] Unutilized LFG reflects RNG potential from landfills that do not have existing landfill-to-energy projects.

also contain components collected during runoff: soil, metals, organic compounds, animal waste, oils, and solid debris such as leaves and branches.

Processing of the influent to a large water resource recovery facility (WRRF) is comprised typically of four stages: pre-treatment, primary, secondary, and tertiary treatments. These stages consist of mechanical, biological, and sometimes chemical processing.

- Pre-treatment removes all the materials that can be easily collected from the raw wastewater that may otherwise damage or clog pumps or piping used in treatment processes.
- In the primary treatment stage, the wastewater flows into large tanks or settling bins, thereby allowing sludge to settle while fats, oils, or greases rise to the surface.
- The secondary treatment stage is designed to degrade the biological content of the wastewater and sludge, and is typically done using water-borne micro-organisms in a managed system.
- The tertiary treatment stage prepares the treated effluent for discharge into another ecosystem, and often uses chemical or physical processes to disinfect the water.

The treated sludge from the WRRF can be landfilled, and during processing it can be treated via anaerobic digestion, thereby producing methane which can be used for beneficial use with the appropriate capture and conditioning systems put in place.

To determine the WRRFs in Michigan, ICF used the Clean Watersheds Needs Survey (CWNS) conducted in 2012 by the U.S. EPA, an assessment of capital investment needed for wastewater collection and treatment facilities to meet the water quality goals of the Clean Water Act, and includes more than 14,500 WRRFs. ICF distinguishes between facilities based on location and facility size as a measure of average flow (in units of million gallons per day, MGD). ICF also reviewed more than 1,200 facilities that are reported to have anaerobic digesters in place, as reported by the Water Environment Federation.

To estimate the amount of RNG produced from wastewater at WRRFs, ICF used data reported by the U.S. EPA,[35] a study of WRRFs in New York State,[36] and previous work published by AGF.[37] ICF used an average energy yield of 7.003 MMBtu/MG of wastewater.

There are 393 WRRFs in Michigan, with a total flow of over 1,360 MGD. Of the 393 WRRFs, 59 have AD systems with a total flow of 166 MGD, or 12% of Michigan's total flow. These existing AD systems collect biogas and generally use it to produce electricity (which is eligible for REC generation) or direct heat applications. The table below summarizes WRRFs by flow and RNG potential for the ten regions and the entire state.

[35] US EPA, Opportunities for Combined Heat and Power at Wastewater Treatment Facilities, October 2011. Available online here.

[36] Wightman, J and Woodbury, P., Current and Potential Methane Production for Electricity and Heat from New York State Wastewater Treatment Plants, New York State Water Resources Institute at Cornell University. Available online here.

[37] AGF, The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality, September 2011.

Table 3-10. WRRFs by Existing Flow and Region

Region	Large Facilities (>7 MGD)	Small Facilities (<7 MGD)	Total Flow (MGD)	RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	-	53	27.5	0.07
Region 2 – Northwest	-	23	12.4	0.03
Region 3 – Northeast	-	18	8.5	0.02
Region 4 – West Michigan	4	63	137.8	0.35
Region 5 – East Central Michigan	4	32	71.6	0.18
Region 6 – East Michigan	3	60	92.2	0.24
Region 7 – South Central	2	24	40.0	0.10
Region 8 – Southwest	3	33	65.8	0.17
Region 9 – Southeast	4	48	91.9	0.23
Region 10 – Detroit Metro	5	14	816.7	2.09
Michigan Total	**25**	**368**	**1,364.3**	**3.49**

RNG: Thermal Gasification of Biogenic or Renewable Resources

The biomass feedstocks for RNG production potential via thermal gasification include agricultural residues, energy crops, forestry and forest product residues, and the non-biogenic fraction of MSW. Given that biomass gasification technology is at an early stage of commercialization, RNG production potential for these feedstocks cannot be determined to a facility-specific level, in contrast to other feedstocks such as LFG and WRRFs. However, sources of thermal gasification feedstocks can be approximated at a regional level based on existing land use patterns and population levels. The specific approach for each feedstock is outlined below.

To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems. This factor is based in part on the 2011 AGF Report on RNG, indicating a range of thermal gasification efficiencies in the range of 60% to 70%, depending upon the configuration and process conditions. The report authors also used a conversion efficiency of 65% in their assessment. More recently, GTI estimated the potential for RNG from the thermal gasification of wood waste in California, and assumed a conversion efficiency of 60%.[38]

[38] GTI, Low-Carbon Renewable Natural Gas from Wood Wastes, February 2019, available online at https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf

Agricultural Residues

Agricultural residues include the material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. More specifically, this resource is inclusive of the unusable portion of crop, stalks, stems, leaves, branches, and seed pods. Agricultural residues (and sometimes crops) are often added to anaerobic digesters.

ICF extracted information from the U.S. DOE Bioenergy KDF, including the following agricultural residues relevant to Michigan: corn stover, noncitrus residues, tree nut residues, and wheat straw. These estimates are based on modeling undertaken as part of the 2016 Billion Ton Study, and utilizes the Policy Analysis System (POLYSYS), a policy simulation model of the U.S. agricultural sector. The POLYSYS modeling framework simulates how commodity markets balance supply and demand via price adjustments based on known economic relationships, and is intended to reflect how agricultural producers respond to new and different agricultural market opportunities, such as for biomass. Available biomass is constrained to not exceed the tolerable soil loss limit of the USDA Natural Resources Conservation Service and to not allow long-term reduction of soil organic carbon.

POLYSYS simulates exogenous price changes introduced as a farmgate price, which then solves for biomass supplies that may be brought to market in response to these prices. The farmgate price is held constant nationwide in all counties over all years of the simulation to allow farmers to respond by changing crops and practices gradually over time.[39]

Agricultural residue volumes are then derived from these estimates at a county level, and reflect total aboveground biomass produced as byproducts of conventional crops, and then limited by sustainability and economic constraints. Not all agricultural residues are made available, as crop residues often provide important environmental benefits, such as protection from wind and water erosion, maintenance of soil organic carbon, and soil nutrient recycling.

In the simulations no land use change is assumed to occur, except within the agricultural sector (i.e. forested land is not converted to agricultural land for agricultural residue or energy crop purposes).

To summarize, the DOE modeling approach attempts to capture the economic and environmental potential of biomass over time, reflected through the introduction of escalating economic incentives to collect and aggregate various agricultural residues at a granular (farm) level. An increase in economic incentive (measured in dollars per dry ton of biomass) leads to the rising availability of biomass, which in turn could be directed towards RNG production (among other productive end uses). ICF extracted data from the Bioenergy KDF modeling at $10 price point increments, from $30/ton to $100/ton, that showed variation in production potential for agricultural residue biomass from 2025 out to 2040.

The table below lists the energy content on a higher heating value (HHV) basis for the various agricultural residues included in the analysis. The energy content is based on values reported by the California Biomass Collaborative.

[39] DOE, 2016. 2016 Billion Ton Report, https://www.energy.gov/eere/bioenergy/2016-billion-ton-report.

Table 3-11. Heating Values for Agricultural Residues

Agricultural Component	MMBtu/ton, dry
Corn stover	15.174
Noncitrus residues	15.476
Tree nut residues	17.194
Wheat straw	15.054

The volume of agricultural residue was extracted at the county level in Michigan. The table below shows an annotated summary of the maximum agricultural residue potential at biomass prices that showed significant variation in 2040, broken down by region.

Table 3-12. Agricultural Residue Production Potential in 2040 by Region (dry tons)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	963	25,336	28,254	38,782
Region 2 – Northwest	20,318	97,618	96,374	90,641
Region 3 – Northeast	15,595	97,414	85,264	82,692
Region 4 – West Michigan	166,328	1,184,611	1,352,845	1,369,436
Region 5 – East Central Michigan	199,670	791,660	1,104,265	1,197,744
Region 6 – East Michigan	486,766	1,738,713	1,692,419	1,723,393
Region 7 – South Central	105,621	579,306	595,868	574,760
Region 8 – Southwest	81,133	773,274	1,032,552	1,140,187
Region 9 – Southeast	201,398	801,103	862,653	829,372
Region 10 – Detroit Metro	9,352	55,855	51,748	49,838
Michigan Total	**1,287,144**	**6,144,890**	**6,902,242**	**7,096,845**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from agricultural residue feedstocks at the different biomass prices in 2040, broken down by the different geographies.

Table 3-13. Agricultural Residue RNG Production Potential in 2040 by Region (tBtu/y)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	0.01	0.25	0.28	0.38
Region 2 – Northwest	0.20	0.97	0.95	0.90
Region 3 – Northeast	0.15	0.96	0.84	0.81
Region 4 – West Michigan	1.64	11.68	13.35	13.51
Region 5 – East Central Michigan	1.95	7.79	10.87	11.80
Region 6 – East Michigan	4.76	17.11	16.66	16.97
Region 7 – South Central	1.03	5.70	5.87	5.66
Region 8 – Southwest	0.80	7.63	10.19	11.25
Region 9 – Southeast	1.97	7.89	8.49	8.17
Region 10 – Detroit Metro	0.09	0.55	0.51	0.49
Michigan Total	**12.63**	**60.53**	**68.01**	**69.95**

Energy Crops

Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. Energy crop estimates are based on the same modeling framework used to derive the agricultural residue estimates, outlined in the previous section. With respect to land use, rather than shifting existing agricultural production (e.g. corn and soy) to energy crop production, DOE's modeling also shows that energy crops are largely grown on idle or available pasture lands, particularly at lower farmgate prices. Similar to agricultural residues, in the simulations no land use change is assumed to occur, except within the agricultural sector (i.e., forested land is not converted to agricultural land for agricultural residue or energy crop purposes).

To summarize, the DOE modeling approach attempts to capture the economic and environmental potential of biomass over time, reflected through the introduction of escalating economic incentives to grow energy crops at a granular (farm) level. An increase in economic incentive (measured in dollars per dry ton of biomass) leads to the rising availability of biomass, which in turn could be directed towards RNG production (among other productive end uses). ICF extracted data from the Bioenergy KDF modeling at $10 price point increments, from $30/ton to $100/ton that showed variation in production potential for energy crops from 2025 out to 2040. The table below lists the energy content on an HHV basis for the various energy crops relevant to Michigan.

Table 3-14. Heating Values for Energy Crops

Energy Crop	Btu/lb, dry	MMBtu/ton, dry
Biomass sorghum	7,240	14.48
Miscanthus	7,900	15.80
Poplar	7,775	15.55
Switchgrass	7,929	15.86
Willow	8,550	17.10

The volume of energy crops was extracted at the county level in Michigan. The table below shows the maximum energy crop production potential broken down by region at biomass prices with significant variation in 2040.

Table 3-15. Energy Crop Production Potential in 2040 by Region (dry tons)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	181,279	189,140	189,267	179,214
Region 2 – Northwest	99,342	121,046	132,954	161,510
Region 3 – Northeast	126,570	195,393	203,129	228,662
Region 4 – West Michigan	657,442	1,981,729	1,602,460	1,953,107
Region 5 – East Central Michigan	38,866	894,677	1,503,020	1,280,928
Region 6 – East Michigan	78,961	1,389,039	1,594,457	1,944,888
Region 7 – South Central	77,120	1,016,716	937,507	1,040,974
Region 8 – Southwest	864,296	2,160,014	1,832,502	2,013,347
Region 9 – Southeast	763,023	1,790,265	1,510,526	1,864,410
Region 10 – Detroit Metro	17,148	122,345	111,982	123,596
Michigan Total	**2,904,047**	**9,860,364**	**9,617,804**	**10,790,636**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from energy crop feedstocks at the different biomass prices in 2040, broken down by region.

Table 3-16. Energy Crop RNG Production Potential in 2040 by Region (tBtu/y)

Region	Biomass Price $40	Biomass Price $60	Biomass Price $80	Biomass Price $100
Region 1 – Upper Peninsula	1.92	1.98	1.95	1.84
Region 2 – Northwest	1.06	1.29	1.40	1.68
Region 3 – Northeast	1.37	2.10	2.16	2.38
Region 4 – West Michigan	7.31	21.17	16.91	20.34
Region 5 – East Central Michigan	0.43	9.42	15.95	13.41
Region 6 – East Michigan	0.88	14.76	16.61	20.24
Region 7 – South Central	0.86	10.83	9.93	10.86
Region 8 – Southwest	9.61	22.99	19.13	20.93
Region 9 – Southeast	8.31	19.12	15.84	19.34
Region 10 – Detroit Metro	0.19	1.30	1.18	1.29
Michigan Total	**31.92**	**104.96**	**101.07**	**112.30**

Forestry and Forest Product Residues

Forestry and forest product residues includes biomass generated from logging, forest and fire management activities, and milling. Logging residues (e.g., bark, stems, leaves, branches), forest thinnings (e.g., removal of small trees to reduce fire danger), and mill residues (e.g., slabs, edgings, trimmings, sawdust) are also considered in the analysis. This includes materials from public forestlands (e.g., state, federal), but not specially designated forests (e.g., roadless areas, national parks, wilderness areas) and includes sustainable harvesting criteria as described in the U.S. DOE Billion Ton Update. The updated DOE Billion Ton study was altered to include additional sustainability criteria. Some of the changes included: [40]

- Alterations to the biomass retention levels by slope class (e.g., slopes with between 40% and 80% grade included 40% biomass left on-site, compared to the standard 30%).
- Removal of reserved (e.g., wild and scenic rivers, wilderness areas, USFS special interest areas, national parks) and roadless designated forestlands, forests on steep slopes and in wet land areas (e.g., stream management zones), and sites requiring cable systems.
- The assumptions only include thinnings for over-stocked stands and did not include removals greater than the anticipated forest growth in a state.
- No road building greater than 0.5 miles.

These additional sustainability criteria provide a more realistic assessment of available forestland than other studies.

ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g.,

[40] DOE, 2011. *2011 Billion Ton Update – Assumptions and Implications Involving Forest Resources*, http://web.ornl.gov/sci/ees/cbes/workshops/Stokes_B.pdf

mixedwood, hardwood, and softwood). The Bioenergy KDF estimates are based on ForSEAM, a linear programming model constructed to estimate forestland production over time, including both traditional forest products but also products that meet biomass feedstock demands. The model assumes that projected traditional timber demands will be met and estimates costs, land use, and competition between lands. The forestry and forest product residue estimates also reflect a cost minimization framework that minimizes the total costs (harvest costs and other costs) under a production target goal in addition to land, growth, and other constraints. The cost minimization framework includes the POLYSYS model as well as IMPLAN, an input-output model that estimates impacts to the economy.[41]

To summarize, the DOE modeling approach attempts to capture the economic and environmental potential of biomass over time, reflected through the introduction of escalating economic incentives to collect and aggregate various forestry residues at a granular level. An increase in economic incentive (measured in dollars per dry ton of biomass) leads to the rising availability of biomass, which in turn could be directed towards RNG production (among other productive end uses). ICF extracted data from the Bioenergy KDF modeling at price points, from $30/ton to $100/ton, although the price points did not show any variation in production potential for forest and forest product residue biomass from 2025 out to 2040.

The table below lists the energy content on an HHV basis for the various forest and forest product residue elements considered in the analysis. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 3-17. Heating Values for Forestry and Forest Product Residues

Forestry and Forest Product	Btu/lb, dry	MMBtu/ton, dry
Other forest residue	8,597	17.19
Primary mill residue		
Secondary mill residue		
Mixedwood, residue	6,500	13.00
Hardwood, lowland, residue		
Softwood, natural, residue		
Softwood, planted, residue		

The table below shows the maximum forestry and forest product residue potential broken down by region.

[41] DOE, 2016. 2016 Billion Ton Report, https://www.energy.gov/eere/bioenergy/2016-billion-ton-report

Table 3-18. Forestry and Forest Product Residue Production Potential in 2040 by Region (dry tons)

Region	Biomass (dry tons)
Region 1 – Upper Peninsula	716,074
Region 2 – Northwest	202,669
Region 3 – Northeast	147,139
Region 4 – West Michigan	84,554
Region 5 – East Central Michigan	21,438
Region 6 – East Michigan	40,129
Region 7 – South Central	5,027
Region 8 – Southwest	49,917
Region 9 – Southeast	8,768
Region 10 – Detroit Metro	35,829
Michigan Total	**1,311,544**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from forestry and forest product residue feedstocks in 2040, broken down by region.

Table 3-19. Forestry and Forest Product Residue RNG Potential in 2040 by Region (tBtu/y)

Region	RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	6.11
Region 2 – Northwest	1.73
Region 3 – Northeast	1.31
Region 4 – West Michigan	0.93
Region 5 – East Central Michigan	0.21
Region 6 – East Michigan	0.37
Region 7 – South Central	0.06
Region 8 – Southwest	0.55
Region 9 – Southeast	0.10
Region 10 – Detroit Metro	0.40
Michigan Total	**11.76**

Municipal Solid Waste

MSW represents the trash and various items that household, commercial, and industrial consumers throw away—including materials such as glass, construction and demolition (C&D) debris, food waste, paper and paperboard, plastics, rubber and leather, textiles, wood, and yard trimmings. About 25% of MSW is currently recycled, 9% is composted, and 13% is combusted for energy recovery, with the roughly 50% balance landfilled.

ICF limited consideration to biogenic MSW types not covered in other feedstock categories – paper and paperboard, and yard trimmings. We further limited MSW to only the potential for utilizing MSW that would otherwise be landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities. To be clear, ICF assumes that this MSW would not be landfilled so as to avoid any double counting of RNG production potential associated with the capture of landfill gas.

ICF extracted information from the U.S. DOE's Bioenergy KDF, which includes information collected as part of U.S. DOE's Billion Ton Report (updated in 2016). The Bioenergy KDF includes the following waste residues: construction and demolition (C&D) debris, paper and paperboard, plastics, rubber and leather, textiles, wood, yard trimmings, and other. ICF extracted data from the Bioenergy KDF at price points between $30/ton and $60/ton.

The table below lists the energy content on an HHV basis for the various components of MSW relevant to Michigan. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 3-20. Heating Values for MSW Components

MSW Component	Btu/lb, dry	MMBtu/ton, dry
Paper and paperboard	7,642	15.28
Yard trimmings	6,448	12.90

The table below shows the maximum MSW potential broken down by region at prices of $30/ton and $60/ton.

Table 3-21. MSW Production Potential in 2040 by Geography and Price (dry tons)

Region	Biomass Price $30	Biomass Price $60
Region 1 – Upper Peninsula	17,618	22,067
Region 2 – Northwest	13,698	17,157
Region 3 – Northeast	10,554	13,218
Region 4 – West Michigan	78,653	98,507
Region 5 – East Central Michigan	29,414	36,839
Region 6 – East Michigan	44,404	55,612
Region 7 – South Central	23,940	29,983
Region 8 – Southwest	39,900	49,972
Region 9 – Southeast	50,822	63,651
Region 10 – Detroit Metro	198,073	248,074
Michigan Total	**507,076**	**635,080**

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from MSW at prices of $30/ton and $60/ton, broken down by region.

Table 3-22. RNG Production Potential from MSW in 2040 by Region and Price (tBtu/y)

Region	Biomass Price $30	Biomass Price $60
Region 1 – Upper Peninsula	0.17	0.21
Region 2 – Northwest	0.14	0.17
Region 3 – Northeast	0.10	0.13
Region 4 – West Michigan	0.78	0.95
Region 5 – East Central Michigan	0.29	0.35
Region 6 – East Michigan	0.44	0.53
Region 7 – South Central	0.24	0.29
Region 8 – Southwest	0.40	0.48
Region 9 – Southeast	0.50	0.61
Region 10 – Detroit Metro	1.97	2.39
Michigan Total	**5.04**	**6.11**

Feedstock Summary

The following table summarizes the maximum RNG potential for each feedstock and production technology in Michigan, reported in trillion British thermal units (tBtu) per year (tBtu/y). The RNG potential includes different variables for each feedstock, but ultimately reflects the most aggressive options available, such as the highest biomass price and the utilization of all feedstocks at all facilities, including existing RNG production in the state of Michigan.

ICF emphasizes that the estimates included in the table below are based on the theoretical maximum RNG production potential from all feedstocks, and does not apply any economic or technical constraints on feedstock availability. An assessment of resource availability is addressed in Section 4.

Table 3-23. Maximum RNG Production Potential by Feedstock (tBtu/y)

RNG Feedstock	Michigan
Animal Manure	39.0
Food Waste	3.0
Landfill Gas[42]	67.8
Water Resource Recovery Facilities	3.5

[42] Landfill gas estimate includes RNG production potential from landfills with existing landfill-to-energy projects, such as biogas collected and used for heat or electricity.

RNG Feedstock	Michigan
Anaerobic Digestion Sub-Total	*113.3*
Agricultural Residue	69.9
Energy Crops	112.3
Forestry & Forest Product Residue	11.8
Municipal Solid Waste	6.1
Thermal Gasification Sub-Total	*200.1*
Total	**313.4**

4. RNG Supply Scenarios

ICF developed economic supply curves for two separate scenarios for each feedstock and region included in the RNG inventory in Section 3. The RNG potential included in the supply curves are based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple 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).

For the RNG market more broadly, ICF assumed that the national market would grow at a compound annual growth rate slightly higher than we have seen over the last five years—a rate of about 35%.[43] ICF applied a logistic function to model the growth potential of the RNG production, whereby the initial stage of growth is approximated as an exponential, and thereafter growth slows to a linear rate and then approaches a plateau (or limited to no growth) at maturity.

In addition to the RNG inventory, ICF developed two scenarios for each feedstock, with varying assumptions that influence the level of feedstock utilization relative to the RNG inventory.

- **Achievable** represents a low level of feedstock utilization, with utilization levels depending on feedstock, with a range from 20% to 50% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rate of feedstocks for thermal gasification in this scenario is 30%, at lower biomass prices. Overall, the Achievable scenario captures 18% of the RNG feedstock resource in Michigan, based on the inventory developed in Section 3.
- **Feasible** represents balanced assumptions regarding feedstock utilization, with a range from 60% to 85% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranges from 40% to 50% at moderate biomass prices. Overall, the Feasible scenario captures 47% of the RNG feedstock resource available in Michigan.

In the following sub-sections, ICF outlines the potential for RNG for pipeline injection, broken down by the feedstocks presented previously and considering the potential for RNG growth over time, with 2050 being the final year in the analysis. ICF presents the Achievable and Feasible RNG production scenarios, varying both the assumed utilization of existing resources as well as the rate of project development required to deploy RNG at the volumes presented. Consistent with Section 3, we present the RNG potential scenarios for Michigan as a whole, as well as the ten regions.

[43] ICF estimates that nationally there was about 17 tBtu of RNG produced for pipeline injection in 2016 and that there was about 70 tBtu of RNG produced for pipeline injection at the end of 2021—this yields a compound annual growth rate in excess of 30%.

Summary of RNG Potential

The following subsections summarize the RNG potential for each feedstock and production technology by scenario and geography of interest.

Table 4-1 below includes estimates for Michigan for the Achievable and Feasible scenarios and shows the development potential of each feedstock in 2050, reported in units of tBtu per year. For reference, the table also shows the RNG inventory from Section 3.

Table 4-1. Estimated Annual RNG Production in Michigan by 2050 (tBtu/y)

RNG Feedstock		Scenario		
		Achievable	Feasible	Inventory
Anaerobic Digestion	Animal Manure	4.6	9.3	39.0
	Food Waste	1.2	1.8	3.0
	LFG	31.5	53.5	67.8
	WRRFs	1.5	2.3	3.5
Thermal Gasification	Agricultural Residue	3.8	30.3	69.9
	Energy Crops	9.6	42.0	112.3
	Forestry and Forest Product Residue	3.5	5.9	11.8
	Municipal Solid Waste	1.5	3.1	6.1
Total		**57.2**	**148.0**	**313.4**
Percentage of Total Available Feedstock[44]		**18%**	**47%**	**100%**

Table 4-2. Estimated Annual RNG Production by Region in 2050 (tBtu/y)

Region	Scenario		
	Achievable	Feasible	Inventory
Region 1 – Upper Peninsula	3.6	6.1	11.7
Region 2 – Northwest	2.5	4.6	9.4
Region 3 – Northeast	1.8	3.6	7.5
Region 4 – West Michigan	8.6	24.9	57.6
Region 5 – East Central Michigan	3.1	11.9	34.0
Region 6 – East Michigan	6.1	22.2	52.6
Region 7 – South Central	2.2	10.1	22.1
Region 8 – Southwest	7.3	20.2	44.2
Region 9 – Southeast	8.6	21.0	41.8

[44] Total feedstock reflects the maximum volume of RNG feedstocks available in Michigan, including all facilities and all biomass, and no restrictions are applied.

Region	Scenario		
	Achievable	Feasible	Inventory
Region 10 – Detroit Metro	13.4	23.3	32.6
Michigan	**57.2**	**148.0**	**313.4**

The RNG resources in Michigan are diverse, including significant potential from landfills, MSW, animal manure, and energy crops, among other feedstocks. The variety in RNG feedstocks is driven by the diverse nature of Michigan, including predominantly rural areas as well as significant population centers that provide a source of biomass-based wastes.

For the sake of reference, Michigan consumed an average of 673 tBtu of natural gas in residential, commercial, and industrial, and vehicle sectors from 2016 to 2020, with a minimum of 642 tBtu in 2020 and a maximum of 713 tBtu in 2019.[45] In other words, ICF's estimates for RNG deployment in Michigan for the Achievable and Feasible scenarios amount to 8.5% and 22.0% of the average annual natural gas consumption in relevant sectors for the last five years for which there are data available.

Summary of RNG Potential by Scenario

Figure 4-1 through Figure 4-4 below show the total RNG potential for each feedstock by scenario in Michigan from 2025 out to 2050, as well as RNG potential by region in 2050.

In the Achievable scenario (Figure 4-1), RNG from anaerobic digestion feedstocks dominate overall potential, with landfill gas and animal manure making up a large proportion out to 2050. Commercial deployment of the thermal gasification production technology after 2030 sees the increased deployment of feedstocks that utilize that technology, with energy crops and to a lesser degree agricultural residue and forestry residue contributing larger shares of overall potential.

Consistent with the statewide timeseries, regions in Michigan with high feedstock potential from landfills and animal manure are the main sources of RNG production potential in the Achievable scenario (Figure 4-2). For example, the Detroit Metro has significant potential from landfills, while West Michigan has significant potential from animal manure.

Similar to the Achievable scenario, the Feasible scenario shows an early penetration of RNG from anaerobic digestion feedstocks, with an increased penetration of RNG from thermal gasification feedstocks taking place post-2030 (Figure 4-3). With the higher deployment of energy crops and agricultural residues in the Feasible scenarios, regions with large agricultural-based industries contribute a higher share to statewide RNG potential, such as West Michigan, East Michigan, Southeast and Southwest (Figure 4-4).

[45] Based on ICF analysis of data reported by the EIA regarding *Natural Gas Consumption by End Use*, available online at https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMI_A.htm. ICF excluded natural gas used in electric power generation in our consideration here because RNG is unlikely to displace natural gas used in electricity production given its higher cost.

Achievable Scenario

Figure 4-1. Achievable Scenario Annual RNG Production in Michigan, 2025-2050 (tBtu/y)

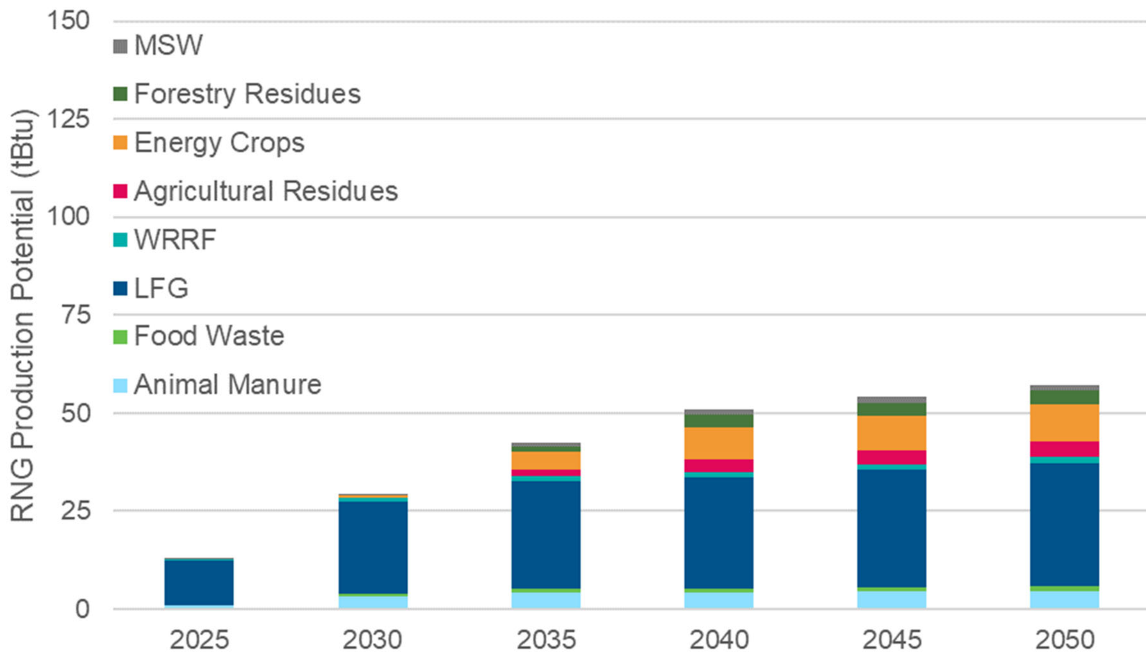
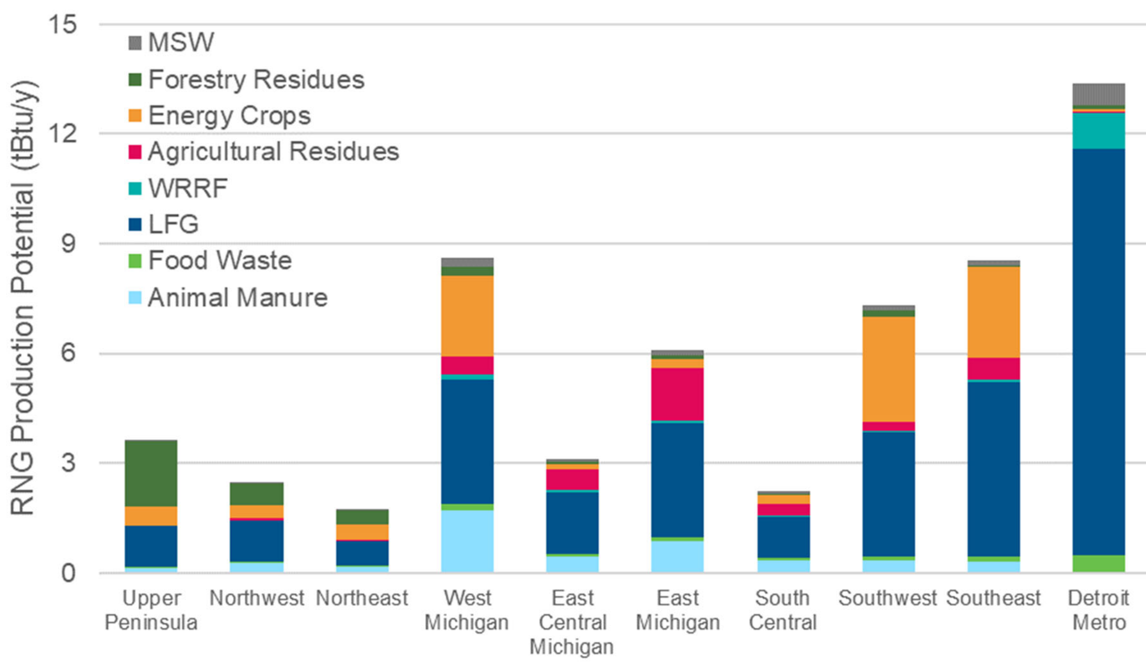


Figure 4-2. Achievable Scenario RNG Production by Region in 2050 (tBtu/y)



Feasible Scenario

Figure 4-3. Feasible Scenario Annual RNG Production in Michigan, 2025-2050 (tBtu/y)

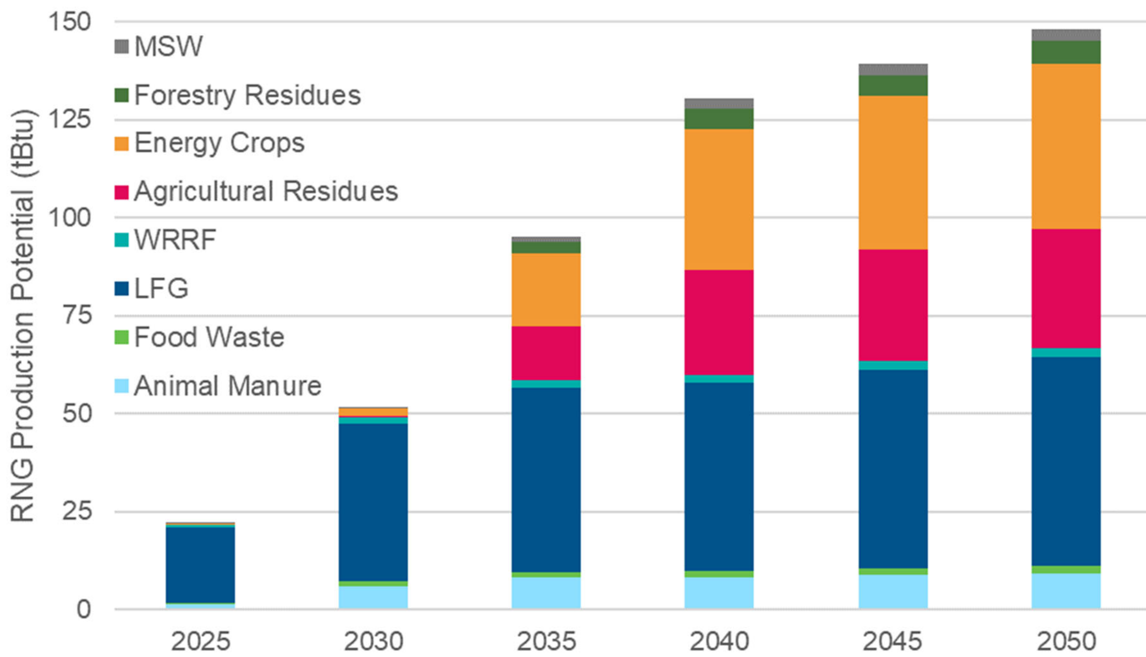
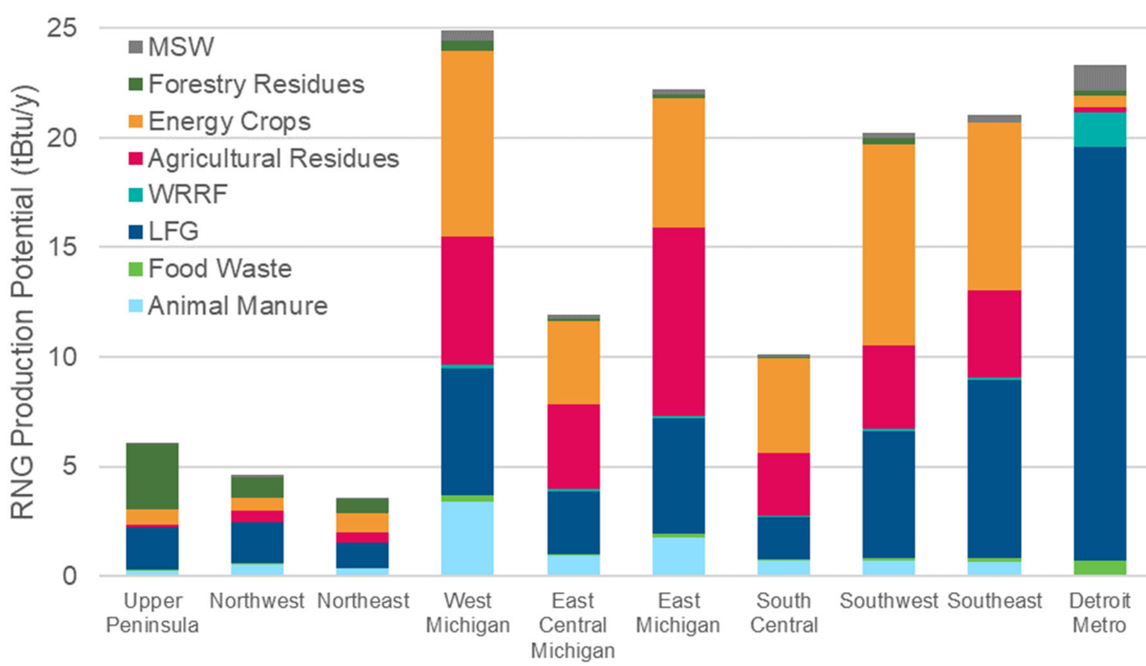


Figure 4-4. Feasible Scenario RNG Production by Region in 2050 (tBtu/y)



RNG: Anaerobic Digestion of Biogenic or Renewable Resources

Animal Manure

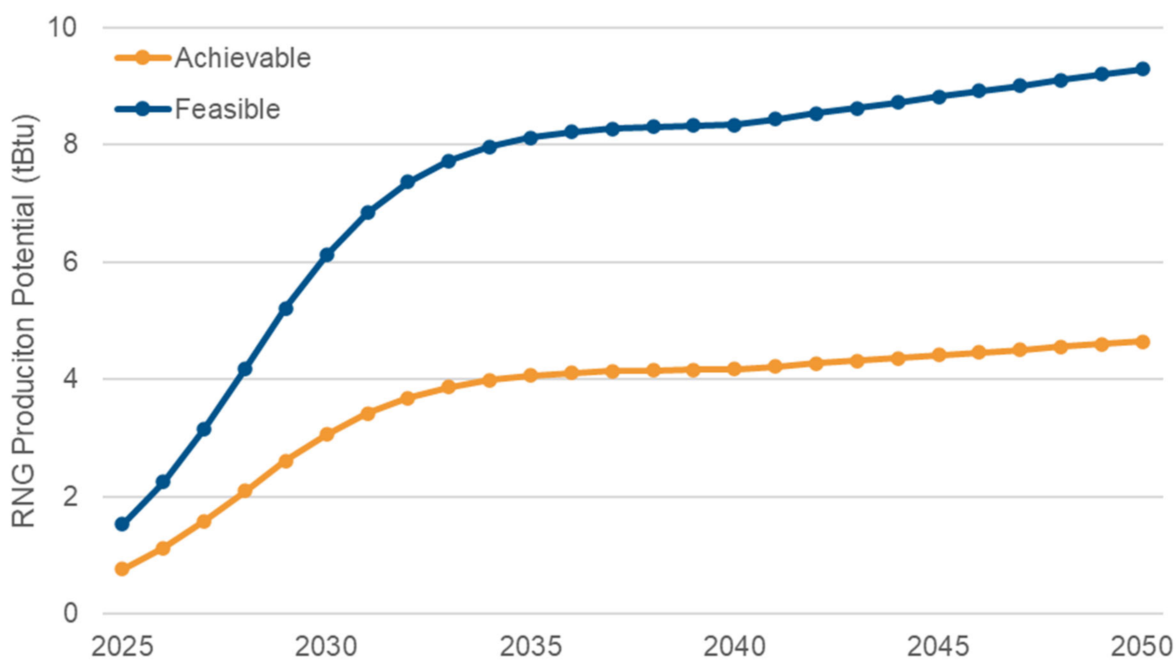
Prior to the application of economic and market constraints for animal manure as an RNG feedstock, ICF applied technical availability factors to each manure type to reflect that not all animal manure can be collected, due to practical considerations such as small farming operations and the inability to collect manure from grazing animals. After applying these technical availability factors for each animal manure type, the total available animal manure potential is reduced by over half.

ICF developed the following assumptions for resource potentials for RNG production from the anaerobic digestion of animal manure in the two scenarios.

- In the Achievable scenario, ICF assumed that RNG could be produced from 30% of the animal manure, after accounting for the technical availability factor.
- In the Feasible scenario, ICF assumed that RNG could be produced from 60% of the animal manure, after accounting for the technical availability factor.

The figure below shows the Achievable and Feasible resource potential from animal manure between 2025 and 2050 in Michigan.

Figure 4-5. Annual RNG Production Potential from Animal Manure in Michigan (tBtu/y)



Food Waste

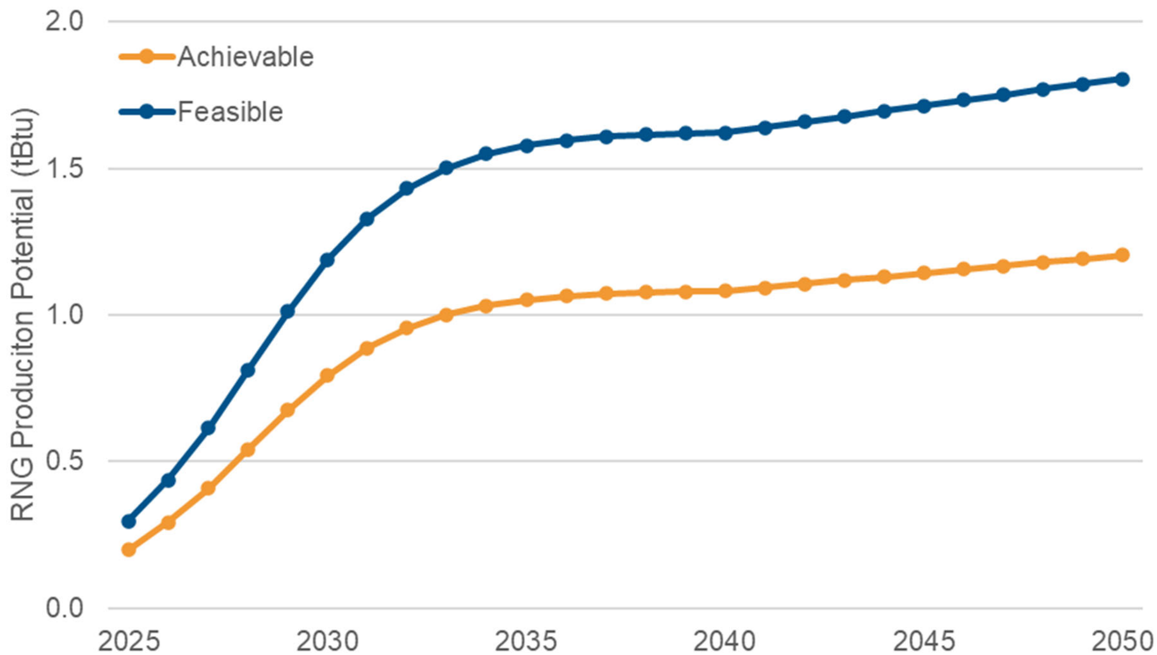
ICF developed the following assumptions for the RNG production potential from food waste in the two scenarios:

- In the Achievable scenario, ICF assumed that 40% of available food waste would be diverted to AD systems.

- In the Feasible scenario, ICF assumed that 60% of available food waste would be diverted to AD systems.

The figure below shows the Achievable and Feasible resource potential scenarios from the anaerobic digestion of food waste between 2025 and 2050 in Michigan.

Figure 4-6. Annual RNG Production Potential from Food Waste in Michigan (tBtu/y)



Landfill Gas

To develop the RNG potential from LFG, ICF extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. EPA, which included more than 2,000 landfills, with 60 in Michigan and included in the inventory. Due to the minimal and declining methane production of waste after 25 years in landfills, in building the scenarios ICF considered only landfills that are either open or were closed post-2000, and landfills with waste-in-place greater than one million tons. In contrast to the overall landfill inventory outlined in Section 3, and summarized in Table 3-7 and Table 3-9, these constraints reduce the number of landfills included in our scenario analysis to 47 in Michigan, summarized by category in Table 4-3 below.

Table 4-3. Landfills included in Scenario Analysis by Region[46]

Region	EPA Candidate Landfills	Landfill-to-Energy Projects	Total Landfills
Region 1 – Upper Peninsula	6	-	6
Region 2 – Northwest	2	1	3
Region 3 – Northeast	2	1	3
Region 4 – West Michigan	1	5	6
Region 5 – East Central Michigan	-	4	4
Region 6 – East Michigan	2	4	7
Region 7 – South Central	-	2	2
Region 8 – Southwest	1	4	5
Region 9 – Southeast	1	3	4
Region 10 – Detroit Metro	-	7	7
Michigan	**15**	**31**	**47**

The U.S. EPA's LMOP database shows that there are at least 31 operational LFG-to-energy projects in Michigan. 20 of the projects capture LFG and combust it in reciprocating engines to make electricity, five landfills have direct use for the energy (e.g., thermal use on-site), and six produce RNG, mostly for use in natural gas vehicles.

The U.S. EPA currently estimates that there are 15 candidate landfills in Michigan that could capture LFG for use as energy, shown in the table below. The U.S. EPA characterizes candidate landfills as those that are accepting waste or have been closed for five years or less, have at least one million tons of WIP, and do not have operational, under-construction, or planned projects. Candidate landfills can also be designated based on actual interest by the site.

[46] Based on data from the LMOP at the U.S. EPA (updated March 2022).

Table 4-4. EPA Candidate Landfills in Michigan

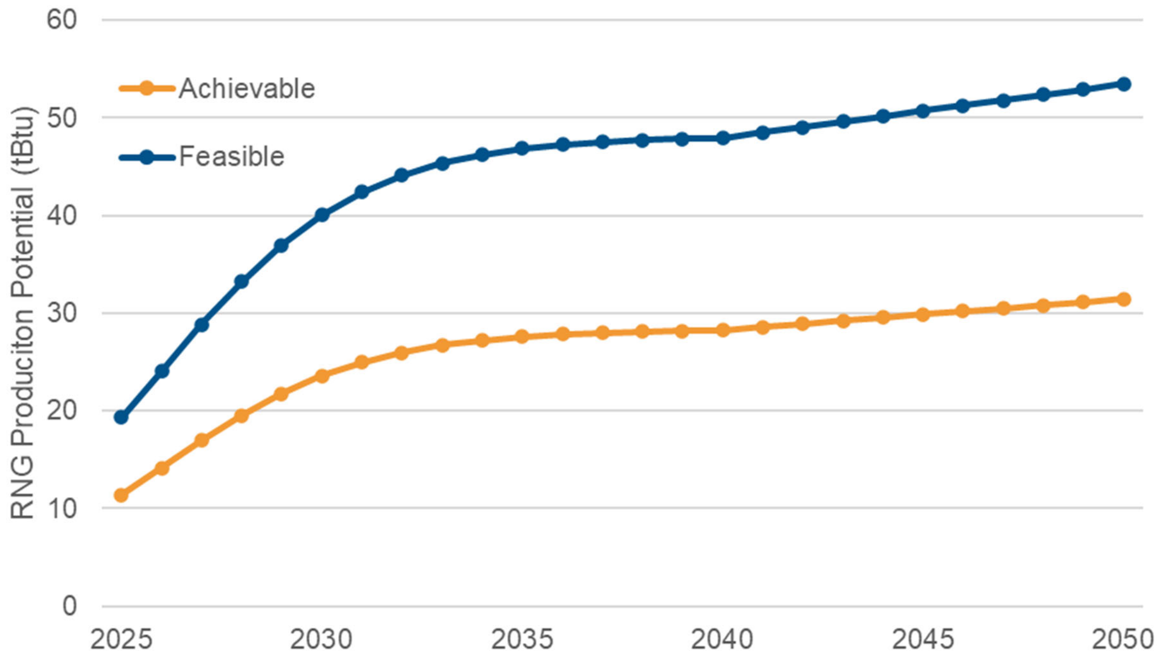
Landfill	County	LFG Collection	RNG Potential (MMBtu/year)
Forest Lawn Landfill	Berrien	Yes	2,324,167
Manistee County LF	Manistee	Yes	667,793
Menominee Landfill	Menominee	No	658,622
Wexford County Landfill	Wexford	Yes	566,898
Tri-City RDF	Sanilac	Yes	447,593
Hastings Sanitary Landfill	Barry	Yes	435,283
K&W LF	Ontonagon	No	382,241
Montmorency-Oscoda-Alpena LF	Montmorency	No	376,232
Huron Landfill	Huron	No	358,248
McGill Road Landfill	Jackson	Yes	346,746
Dafter Sanitary Landfill Inc	Chippewa	No	330,171
Elk Run Sanitary Landfill	Presque Isle	No	317,718
Delta County Landfill	Delta	Yes	309,862
Wood Island Waste Management	Alger	No	309,174
Marquette County SWL	Marquette	No	272,805

ICF developed assumptions for the resource potentials for RNG production at landfills in the two scenarios, considering the potential at LFG facilities with collection systems in place, LFG facilities that do not have collection systems in place, and candidate landfills identified by the U.S. EPA.

- In the Achievable scenario, ICF assumed that 50% of eligible LFG facilities would produce RNG.
- In the Feasible scenario, ICF assumed that 85% of eligible LFG facilities would produce RNG.

The figure below shows the Achievable and Feasible RNG resource potential from LFG between 2025 and 2050 in Michigan.

Figure 4-7. Annual RNG Production Potential from Landfill Gas in Michigan (tBtu/y)



Water Resource Recovery Facilities

There are 393 WRRFs in Michigan, with a total flow of over 1,360 MGD. Of the 393 WRRFs in Michigan, 59 have anaerobic digestion systems with a total flow of 167 MGD, or 12% of the Michigan's total flow. The table below summarizes WRRFs by flow and RNG potential by region in Michigan.

Table 4-5. WRRFs by Existing Flow and Geography

Region	Large Facilities (>7 MGD)	Small Facilities (<7 MGD)	Total Flow (MGD)	RNG Potential (tBtu/y)
Region 1 – Upper Peninsula	-	53	27.5	0.07
Region 2 – Northwest	-	23	12.4	0.03
Region 3 – Northeast	-	18	8.5	0.02
Region 4 – West Michigan	4	63	137.8	0.35
Region 5 – East Central Michigan	4	32	71.6	0.18
Region 6 – East Michigan	3	60	92.2	0.24
Region 7 – South Central	2	24	40.0	0.10
Region 8 – Southwest	3	33	65.8	0.17
Region 9 – Southeast	4	48	91.9	0.23
Region 10 – Detroit Metro	5	14	816.7	2.09
Michigan Total	**25**	**368**	**1,364.3**	**3.49**

The figures and table above illustrate the unique opportunities for Michigan associated with deploying AD systems at WRRFs: roughly 15% of WRRFs have an AD system, covering 12% of flow and RNG potential. Typically, facilities that have AD systems in place are capturing biogas for on-site electricity production rather than for pipeline injection. With an effective policy and regulatory framework, these facilities present a near-term opportunity for RNG to be directed into the pipeline, rather than for on-site electricity production.

The table below shows the 25 largest WRRFs in Michigan, with a flow greater than 7 MGD. In addition to WRRFs that have existing AD systems in place, the WRRF list shows there remains significant potential for WRRFs without AD systems.

Table 4-6. Large WRRFs in Michigan

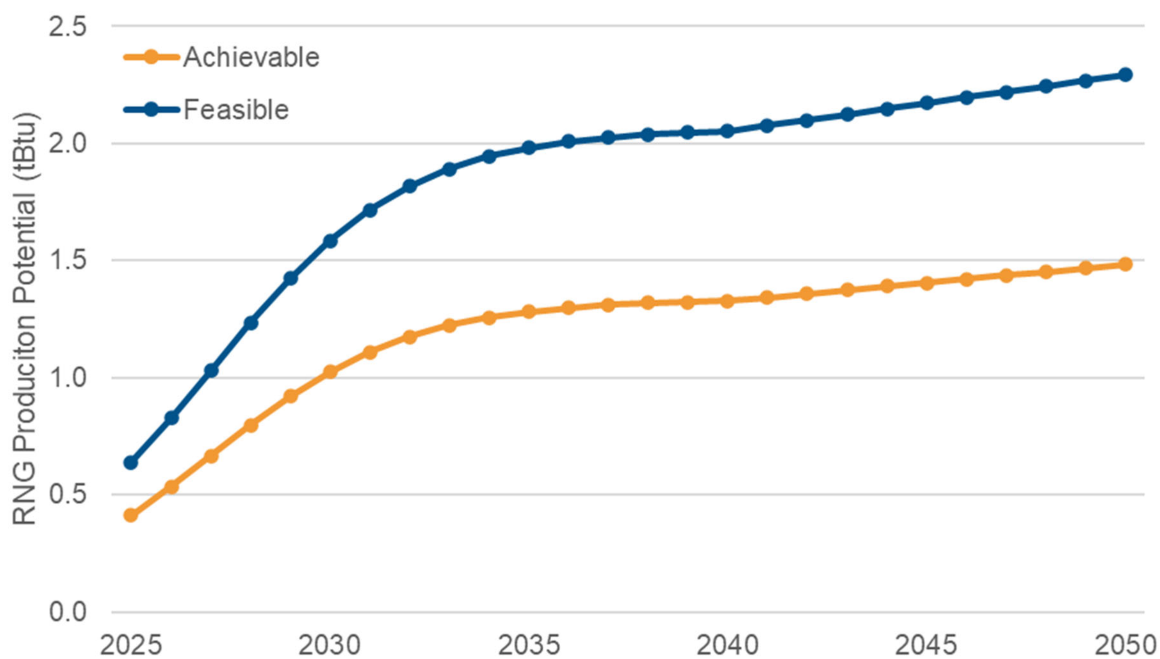
Landfill	County	Flow (MGD)	AD System	RNG Potential (MMBtu/year)
Detroit STP	Wayne	660.5	No	1,688,549
Wyandotte WWTP	Wayne	81.0	No	207,074
Grand Rapids WWTP	Kent	50.4	No	128,846
Flint WPCF	Genesee	43.3	Yes	110,695
Muskegon County STP	Muskegon	32.3	No	82,446
Warren WWTP	Macomb	30.0	No	76,694
Kalamazoo WWTP	Kalamazoo	28.0	No	71,581
Saginaw STP	Saginaw	25.0	No	63,912
YCUA WWTP	Washtenaw	24.2	No	61,953
Wyoming WWTP	Kent	16.5	No	42,182
Ann Arbor WWTP	Washtenaw	15.1	No	38,705
Ragnone DIST.#2 WWTP	Genesee	14.0	No	35,791
Huron Valley WWTP South	Wayne	14.0	No	35,791
Lansing WWTP	Ingham	13.5	No	34,589
Jackson WWTP	Jackson	13.4	Yes	34,333
East Lansing WWP	Ingham	13.4	No	34,257
Monroe Metro WWTP	Monroe	13.4	No	34,257
Battle Creek STP	Calhoun	11.0	No	28,121
Port Huron WWTP	St. Clair	11.0	No	28,121
Holland WTF	Ottawa	9.5	No	24,286
Bay City STP	Bay	9.1	No	23,264
Midland WWTP	Midland	8.5	Yes	21,730
Pontiac STP	Oakland	8.0	Yes	20,452
West Bay Regional WWTP	Bay	7.9	Yes	20,273
Benton Harbor-St Joseph	Berrien	7.2	Yes	18,432

ICF developed the following assumptions for the resource potentials for RNG production at WRRFs in the two scenarios:

- In the Achievable scenario, ICF assumed that 50% of the WRRFs with a capacity greater than 7 MGD would produce RNG.
- In the Feasible scenario, ICF assumed that 75% of the WRRFs with a capacity greater than 3.5 MGD would produce RNG.

The figure below shows the Achievable and Feasible RNG resource potential from WRRFs between 2025 and 2050 in Michigan.

Figure 4-8. Annual RNG Production Potential from WRRFs in Michigan (tBtu/y)



RNG: Thermal Gasification of Biogenic or Renewable Resources

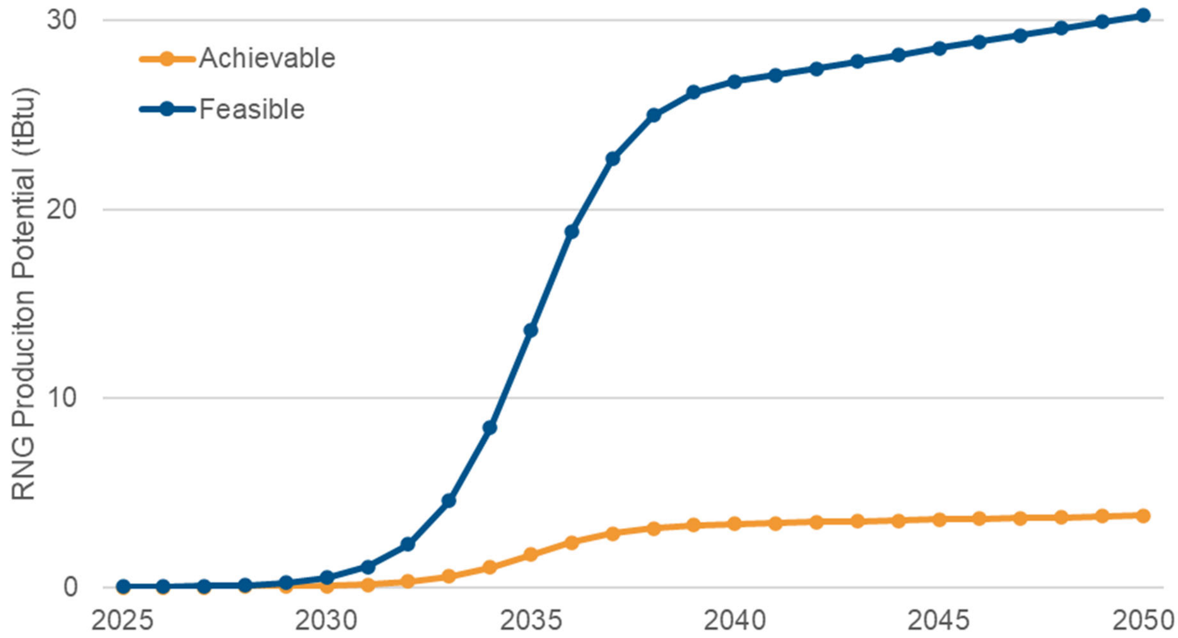
Agricultural Residues

ICF developed the following assumptions for the RNG production potential from agricultural residues in the two scenarios.

- In the Achievable scenario, ICF assumed that 30% of the agricultural residues available at $40/dry ton would be diverted to thermal gasification systems.
- In the Feasible scenario, ICF assumed 50% of the agricultural residues available at $60/dry ton would be diverted to thermal gasification systems.

The figure below shows the Achievable and Feasible RNG resource potential scenarios from the thermal gasification of agricultural residues between 2025 and 2050 in Michigan.

Figure 4-9. Annual RNG Production Potential from Agricultural Residues in Michigan (tBtu/y)



Energy Crops

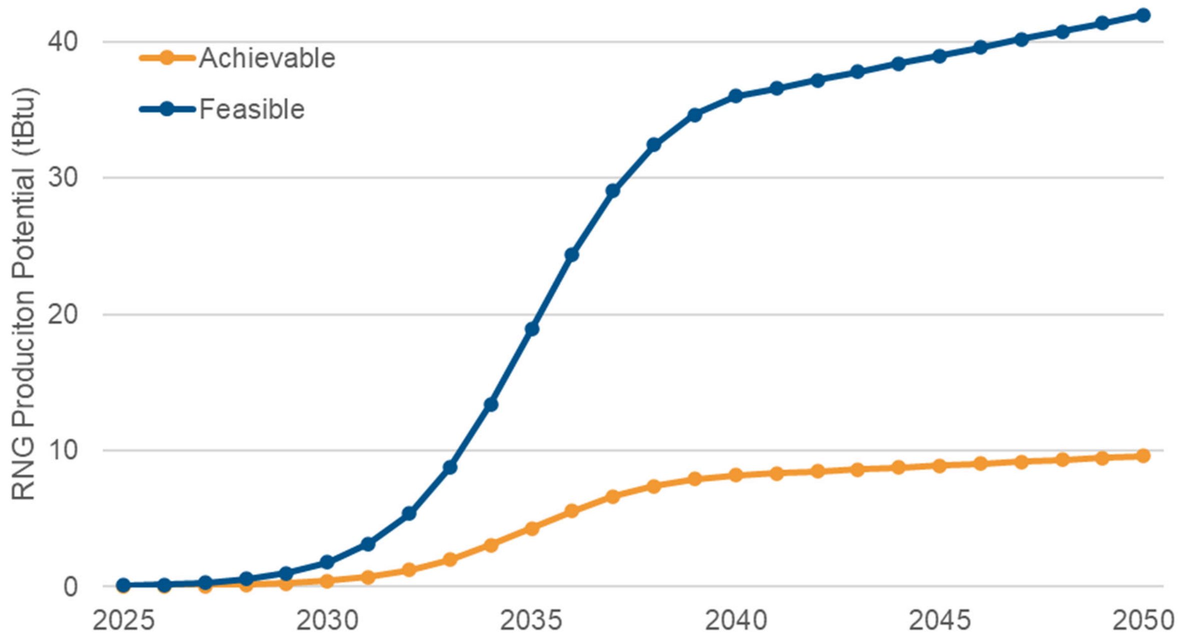
Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. ICF extracted data from the Bioenergy KDF at $10 price point increments, from $30/ton to $100/ton that showed variation in production potential for energy crops from 2025 out to 2040.

ICF developed assumptions for the RNG production potential from energy crops for the two scenarios:

- In the Achievable scenario, ICF assumed that 30% of the energy crops available at $40/dry ton would be diverted to thermal gasification systems.
- In the Feasible scenario, ICF assumed that 40% of the energy crops available at $60/dry ton would be diverted to thermal gasification systems.

Figure 4-10 below shows the RNG resource potential from the thermal gasification of energy crops between 2025 and 2050 in the Achievable and Feasible scenarios in Michigan.

Figure 4-10. Annual RNG Production Potential from Energy Crops in Michigan (tBtu/y)



Forestry and Forest Product Residues

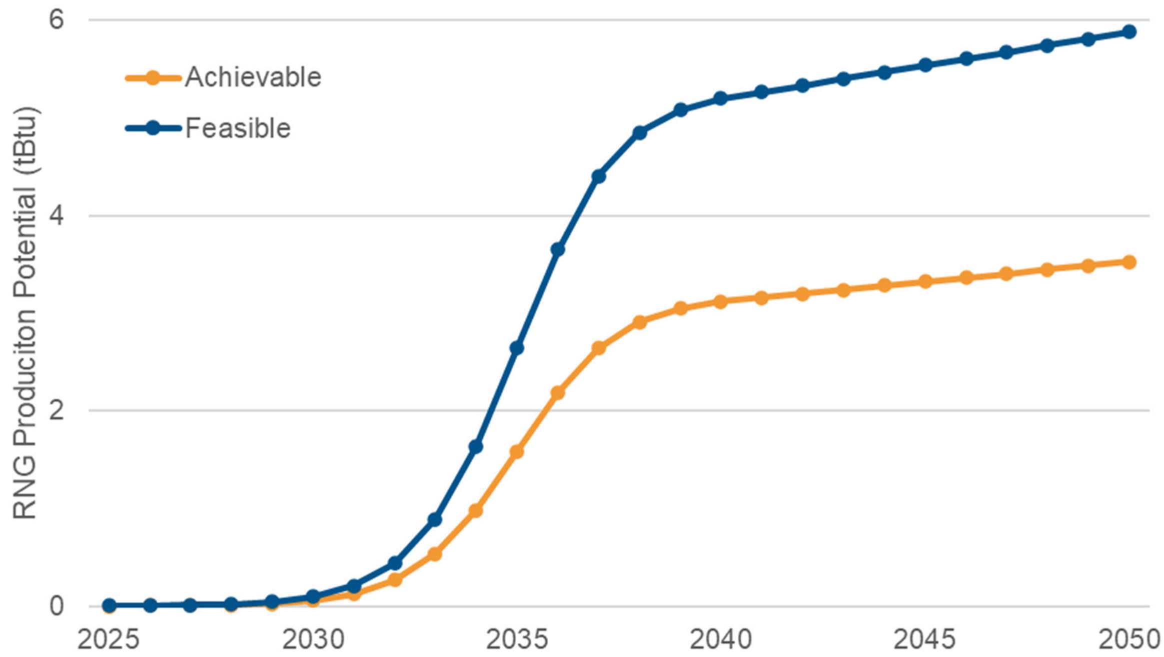
ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood). ICF extracted data from the Bioenergy KDF at three price points, $30/ton and $60/ton, that showed variation in production potential for forest and forest product residue biomass from 2025 out to 2040.

ICF developed the following assumptions for the RNG production potential from forest residues in the two scenarios:

- In the Achievable scenario, ICF assumed that 30% of the forest and forestry product residues available at $40/dry ton would be diverted to thermal gasification systems.
- In the Feasible scenario, ICF assumed that 50% of the forest and forestry product residues available at $60/dry ton would be diverted to thermal gasification systems.

Figure 4-11 below shows the RNG resource potential from the thermal gasification of forestry and forest product residues between 2025 and 2050 in the Achievable and Feasible scenarios in Michigan.

Figure 4-11. Annual RNG Production Potential from Forestry Residues in Michigan (tBtu/y)



Municipal Solid Waste

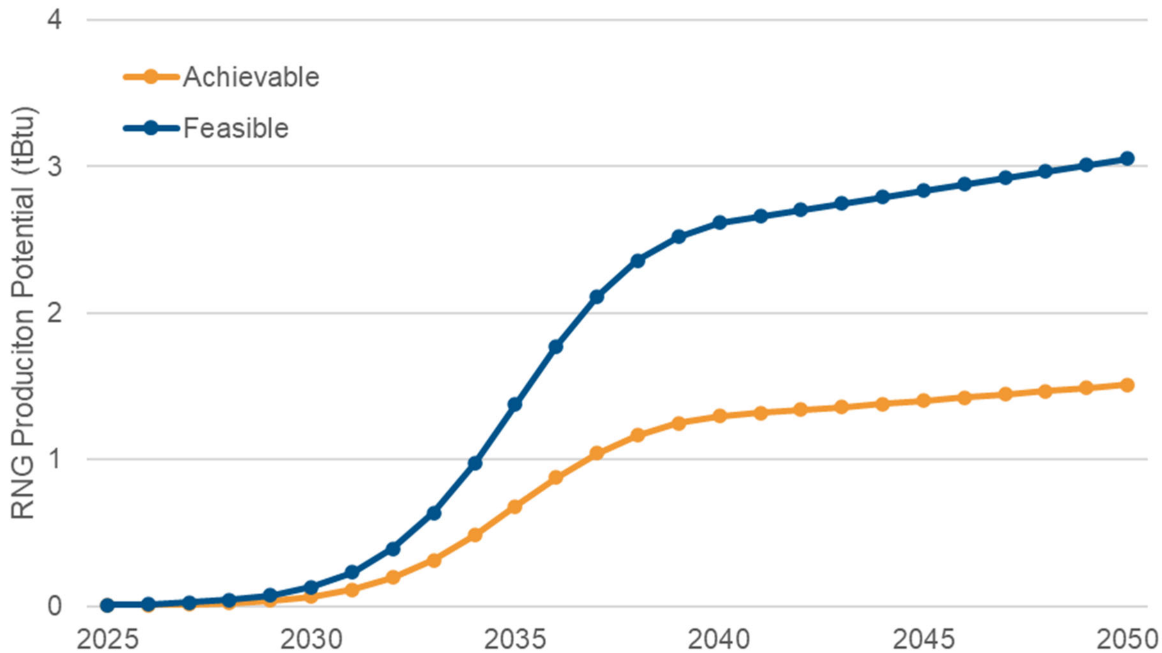
ICF extracted MSW information from the U.S. DOE's Bioenergy KDF, which includes information collected as part of U.S. DOE's Billion Ton Report. ICF limited our consideration to the potential for utilizing MSW that is currently landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities. The MSW volumes available at different prices are derived from a variety of sources, including county-level tipping fees and costs associated with sorting.

ICF developed assumptions for the RNG production potential from MSW for the two scenarios:

- In the Achievable scenario, ICF assumed that 30% of the biogenic fraction of MSW available at $40/dry ton from the Bioenergy KDF for paper and paperboard, and yard trimmings could be gasified.
- In the Feasible scenario, ICF assumed 50% of the biogenic fraction of MSW available at $60/dry ton from the Bioenergy KDF for paper and paperboard and yard trimmings could be gasified.

The figure below shows the RNG resource potential from the thermal gasification of MSW between 2025 and 2050 in the Achievable and Feasible scenarios in Michigan.

Figure 4-12. Annual RNG Production Potential from MSW in Michigan (tBtu/y)



5. RNG Production Cost Assessment

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings outlined previously. ICF characterizes costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput in units of standard cubic feet per minute [SCFM]), 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. Table 5-1 below outlines some of ICF's baseline assumptions that we employ in our RNG costing model.

Table 5-1. Illustrative ICF RNG Cost Assumptions

Cost Parameter	ICF Cost Assumptions
Capital Costs	
Facility Sizing	▪ Differentiate by feedstock and technology type: anaerobic digestion and thermal gasification. ▪ Prioritize larger facilities to the extent feasible but driven by resource estimate.
Gas Conditioning and Upgrade	▪ Vary by feedstock type and technology required.
Compression	▪ Capital costs for compressing the conditioned/upgraded gas for pipeline injection.
O&M Costs	
Operational Costs	▪ Costs for each equipment type—digesters, conditioning equipment, collection equipment, and compressors—as well as utility charges for estimated electricity consumption.
Feedstock	▪ Feedstock costs (for thermal gasification), ranging from \$30 to \$60 per dry ton.
Delivery	▪ The costs of delivering the same volumes of biogas that require pipeline construction greater than 1 mile will increase, depending on feedstock/technology type, with a typical range of \$1–\$5/MMBtu.
Levelized Cost of Gas	
Project Lifetimes	▪ Calculated based on the initial capital costs in Year 1, annual operational costs discounted, and RNG production discounted accordingly over a 20-year project lifetime.

ICF presents the costs used in our analysis as well as the levelized cost of energy (LCOE) for RNG in different end uses. The LCOE is a measure of the average net present cost of RNG production for a facility over its anticipated lifetime. The LCOE enables us to compare across RNG feedstocks and other energy types on a consistent per unit energy basis. The LCOE can also be considered the average revenue per unit of RNG (or energy) produced that would be required to recover the costs of constructing and operating the facility during an assumed lifetime. The LCOE calculated as the discounted costs over the lifetime of energy producing facility (e.g., RNG production) divided by a discounted sum of the actual energy amounts produced. The LCOE is calculated using the following formula:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where I_t is the capital cost expenditures (or investment expenditures) in year t, M_t represents the operations and maintenance expenses in year t, F_t represents the feedstock costs in year t (where appropriate), E_t represents the energy (i.e., RNG) produced in year t, r is the discount rate, and n is the expected lifetime of the production facility.

ICF notes that our cost estimates are not intended to replicate a developer's estimate when deploying a project. For instance, ICF recognizes that the cost category "gas conditioning and upgrading" actually represents an array of decisions that a project developer would have to make with respect to CO_2 removal, H_2S removal, siloxane removal, N_2/O_2 rejection, deployment of a thermal oxidizer, among other elements.

In addition, the cost assumptions attempt to strike a balance between existing or near-term capital and operational expenditures, and the potential for project efficiencies and associated cost reductions that may eventuate over time as the RNG industry expands. For example, in general construction and engineering costs may decline from present levels driven by the development and implementation of modular technology systems or facilities.

These cost estimates also do not reflect the potential value of the environmental attributes associated with RNG, nor the current markets and policies that provide credit for these environmental attributes. While this section focuses purely on the costs associated with the production of RNG, Section 0 discusses in more detail the market prices for RNG and the associated value of the environmental characteristics of RNG.

Furthermore, we understand that project developers have reported a wide range of interconnection costs, with numbers as low as $200,000 reported in some states, and as high as $9 million in other states. We appreciate the variance between projects, including those that use anaerobic digestion or thermal gasification technologies, and our supply-cost curves are meant to be illustrative, rather than deterministic. This is especially true of our outlook to 2050—we have *not* included significant cost reductions that might occur as a result of a rapidly growing RNG market or sought to capture a technological breakthrough or breakthroughs. For anaerobic digestion and thermal gasification systems we have focused on projects that have reasonable scale, representative capital expenditures, and reasonable operations and maintenance estimates.

To some extent, ICF's cost modeling does presume changes in the underlying structure of project financing, which is currently linked inextricably to revenue sharing associated with environmental commodities in the federal Renewable Fuel Standard (RFS) market and California's Low Carbon Fuel Standard (LCFS) market. Our project financing assumptions likely have a lower return than investors may be expecting in the market today; however, our cost assessment seeks to represent a more mature market to the extent feasible, whereby upward of 1,000-4,500 tBtu per year of RNG is being produced. In that regard, we implicitly assume that contractual arrangements are likely considerably different and local/regional challenges with respect to RNG pipeline injection have been overcome.

Table 5-2 provides a summary of the different cost ranges for each RNG feedstock and technology.

Table 5-2. Summary of Cost Ranges by Feedstock Type

	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

RNG Production Costs via Anaerobic Digestion

Animal Manure

ICF developed assumptions for the region by distinguishing between animal manure projects, based on a combination of the size of the farms and assumptions that certain areas would need to aggregate or cluster resources to achieve the economies of scale necessary to warrant an RNG project. There is some uncertainty associated with this approach because an explicit geospatial analysis was not conducted; however, ICF did account for considerable costs in the operational budget for each facility assuming that aggregating animal manure would potentially be expensive.

Table 5-3 includes the main assumptions used to estimate the cost of producing RNG from animal manure, while Table 5-4 that follows provides example cost inputs for low cost and high animal manure facilities.

Table 5-3. Cost Consideration in LCOE Analysis for RNG from Animal Manure

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 15-25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $1.0 to $2.2 million, depending on facility ▪ $0.1 to $0.3 million, depending on facility ▪ $0.25 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $1.5 million ▪ $2.0 million ▪ $0.1–$0.325 million
Other	▪ Value of digestate ▪ Tipping fee	▪ Valued for dairy at about $100/cow/y ▪ Excluded from analysis
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-4. Example Facility-Level Cost Inputs for RNG from Animal Manure

Factor	High LCOE	Low LCOE
Facility size (cows	1,300	3,600
Biogas production (SCFM)	90	1,300
Capital: collection	$2.15 million	$21.59 million
Capital: conditioning (CO2/O2 removal)	$1.035 million	$2.185 million
Capital: sulfur treatment	$0.1 million	$0.3 million
Capital: nitrogen rejection	$0.25 million	$2.5 million
Capital: compressor	$0.1 million	$0.325 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.11 million	$1.61 million
Construction and engineering: installation	$0.87 million	$1.83 million
Construction and engineering: owner's cost	$0.35 million	$0.73 million

ICF reports a range of LCOE for RNG from animal manure at $14.53/MMBtu to $49.17/MMBtu for Michigan. There are likely additional costs that RNG from animal manure will face. For instance, Michigan's dairies continue to bed animals almost exclusively on sand,[47] and while some projects may convert dairies to digestate-based bedding alternatives, this should not be assumed as a baseline for determining costs. As a result of this baseline condition, additional sand separation may be required for manure handling.

Food Waste

ICF made the simplifying assumption that food waste processing facilities would be purpose-built and be capable of processing 60,000 tons of waste per year. ICF estimates that these facilities would produce about 500 SCFM of biogas for conditioning and upgrading before pipeline injection.

In addition to the other costs included in other anaerobic digestion systems, we also included assumptions about the cost of collecting food waste and processing it accordingly (see Table 5-5). Table 5-6 that follows provides example cost inputs for low cost and high food waste facilities.

Table 5-5. Cost Consideration in LCOE Analysis for RNG from Food Waste Digesters

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 95% ▪ 60,000 tons per year
Dedicated Equipment	▪ Organics processing ▪ Digester	▪ $10.0 million ▪ $12.0 million
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 million ▪ $1.0 million
Utility Costs	▪ Electricity: 28 kWh/MMBtu ▪ Natural Gas: 5% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1.5 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
Other	▪ Tipping fees	▪ Statewide average of $42.77
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $1.5 million ▪ $2 million ▪ $0.1–$0.325 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-6. Example Facility-Level Cost Inputs for RNG from Food Waste

[47] Based on information submitted in a comment by Consumers Energy.

Factor	High LCOE	Low LCOE
Food waste processed (ton/y)	30,000	120,000
Biogas production (SCFM)	250	1,000
Capital: organics processing	$7.0 million	$12.5 million
Capital: digester	$7.2 million	$19.2 million
Capital: collection	$0.17 million	$0.44 million
Capital: conditioning (CO2/O2 removal)	$1.36 million	$3.8 million
Capital: sulfur treatment	$0.1 million	$0.5 million
Capital: nitrogen rejection	$0.3 million	$2.5 million
Capital: compressor	$0.13 million	$0.33 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.31 million	$1.53 million
Construction and engineering: installation	$0.97 million	$2.3 million
Construction and engineering: owner's cost	$0.4 million	$0.91 million

ICF assumed that food waste facilities would be able to offset costs with tipping fees. ICF used values presented by an analysis of municipal solid waste landfills by Environmental Research & Education Foundation (EREF). The tipping fees reported by EREF for 2019, including Michigan state-wide average, are shown in Table 5-7.

Table 5-7. Average Tipping Fee by Region ($/ton)[48]

Region	Tipping Fee
Michigan, statewide average	$42.77
Midwest: IL, IN, IA, KS, MI, MN, MO, NE, OH, OH, WI	$47.85
Rest of U.S.	
Northeast: CT, DE, ME, MD, MA, NH, NJ, NY, PA, RI, VA, WV	$68.69
Mountains / Plains: CO, MT, ND, SD, UT, WY	$47.83
Pacific: AK, AZ, CA, HI, ID, NV, OR, WA	$72.03
South Central: AR, LA, NM, OK, TX	$39.66
Southeast: AL, FL, GA, KY, MS, NC, SC, TN	$46.26
National Average	***$53.72***

[48] Environmental Research & Education Foundation, Analysis of MSW Landfill Tipping Fees–January 2021. Retrieved from www.erefdn.org.

The values listed in Table 5-7 are generally the fees associated with tipping municipal solid waste—the tipping fees for construction and debris tend to be higher because the materials take up more space in landfills. ICF developed our cost estimates assuming that anaerobic digesters discounted the tipping fee for food waste compared to MSW landfills by 20%.

ICF reports an estimated LCOE of RNG from food waste of $18.35/MMBtu to $29.39/MMBtu.

Landfill Gas

ICF developed assumptions for each region by distinguishing between four types of landfills: candidate landfills[49] without collection systems in place, candidate landfills with collection systems in place, landfills[50] without collection systems in place, and landfills with collections systems in place.[51] For each region, ICF further characterized the number of landfills across these four types of landfills, distinguishing facilities by estimated biogas throughput (reported in units of SCFM of biogas).

For utility costs, ICF assumed 25 kWh per MMBtu of RNG injected and 6% of geological or fossil natural gas used in processing. Electricity costs and delivered natural gas costs were reflective of industrial rates reported at the state level by the EIA.

Table 5-8 summarizes the key parameters that ICF employed in our cost analysis of LFG, while the table that follows provides example cost inputs for low cost and high LFG facilities.

Table 5-8. Cost Consideration in LCOE Analysis for RNG from Landfill Gas

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 25 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $1.5 million ▪ $2 million ▪ $0.13–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

[49] The EPA characterizes candidate landfills as one that is accepting waste or has been closed for five years or less, has at least one million tons of WIP, and does not have an operational, under-construction, or planned project. Candidate landfills can also be designated based on actual interest by the site.
[50] Excluding those that are designated as candidate landfills.
[51] Landfills that are currently producing RNG for pipeline injection are included here.

Table 5-9. Example Facility-Level Cost Inputs for RNG from LFG

Factor	High LCOE	Low LCOE
Biogas production (SCFM)	240	4,800
Capital: collection	$0.17 million	$3.3 million
Capital: conditioning (CO_2/O_2 removal)	$0.85 million	$7.0 million
Capital: sulfur treatment	$0.1 million	$1.0 million
Capital: nitrogen rejection	$0.75 million	$2.5 million
Capital: compressor	$0.13 million	$0.45 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.3 million	$5.9 million
Construction and engineering: installation	$0.96 million	$3.2 million
Construction and engineering: owner's cost	$0.38 million	$1.3 million

ICF reports an estimated LCOE of RNG from LFG ranging from $9.92/MMBtu to $26.85/MMBtu.

Water Resource Recovery Facilities

ICF developed assumptions for each region by distinguishing between WRRFs based on the throughput of the facilities. The table below includes the main assumptions used to estimate the cost of producing RNG at WRRFs while the table that follows provides example cost inputs for low cost and high WRRF facilities.

Table 5-10. Cost Consideration in LCOE Analysis for RNG from WRRFs

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 26 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $1.5 million ▪ $2 million ▪ $0.1–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-11. Example Facility-Level Cost Inputs for RNG from WRRFs

Factor	High LCOE	Low LCOE
Biogas production (SCFM)	60	2,920
Capital: collection	$0.13 million	$1.98 million
Capital: conditioning (CO2/O2 removal)	$1.36 million	$8.6 million
Capital: sulfur treatment	$0.05 million	$1.2 million
Capital: nitrogen rejection	$0.20 million	$5.0 million
Capital: compressor	$0.10 million	$0.45 million
Capital: pipeline (on-site)	$2.0 million	$2.0 million
Capital: utility interconnect	$1.5 million	$1.5 million
O&M: electricity and natural gas	$0.74 million	$3.61 million
Construction and engineering: installation	$0.93 million	$4.3 million
Construction and engineering: owner's cost	$0.37 million	$1.7 million

ICF reports an estimated LCOE of RNG from WRRFs of $10.90/MMBtu and up to $70.86/MMBtu for smaller WRRFs.

RNG Production Costs via Thermal Gasification

ICF used similar assumptions across the thermal gasification of feedstocks, including agricultural residue, forestry residue, energy crops, and MSW. There is considerable uncertainty around the costs for thermal gasification of feedstocks, as the technology has only been deployed at pilot scale to date or in the advanced stages of demonstration at pilot scale. This is in stark contrast to the anaerobic digestion technologies considered previously.

ICF reports here on a range of facilities processing different volumes of feedstock (in units of tons per day, or tpd) that we employed for conducting the cost analysis, with cost assumptions outlined in Table 5-12 and example cost inputs for low cost and high thermal gasification facilities shown in Table 5-13.

Table 5-12. Thermal Gasification Cost Assumptions

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 90% ▪ 1,000–2,000 tpd
Dedicated Equipment & Installation Costs	▪ Feedstock handling (drying, storage) ▪ Gasifier ▪ CO_2 removal ▪ Syngas reformer ▪ Methanation ▪ Other (cooling tower, water treatment) ▪ Miscellany (site work, etc.) ▪ Construction / Engineering	▪ $20–22 million ▪ $60 million ▪ $25 million ▪ $10 million ▪ $20 million ▪ $10 million ▪ All-in: $335 million for 1,000 tpd
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ Average of 12.5 ¢/kWh for Michigan ▪ Average of $6.86/MMBtu for Michigan
Operations & Maintenance	▪ Feedstock ▪ 3 FTE for maintenance ▪ Miscellany: water sourcing, treatment/disposal	▪ $30/dry ton ▪ 12% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline	▪ $2 million ▪ $1.5–$7.2 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 7-10% ▪ 8%

Table 5-13. Example Facility-Level Cost Inputs for RNG from Thermal Gasification

Factor	High LCOE	Low LCOE
Feedstock processed (tons/day)	200	2,000
Annual RNG production (MMBtu)	440,000	5,210,000
Capital: biomass handling and drying	$6.3 million	$27.3 million
Capital: gasification	$18.0 million	$86.9 million
Capital: syngas shifting	$3.15 million	$13.36 million
Capital: conditioning (CO2 removal)	$7.39 million	$34.17 million
Capital: cooling and water treatment	$2.25 million	$11.18 million
Capital: miscellaneous materials	$7.48 million	$32.01 million
Capital: methanation	$6.17 million	$27.26 million
Capital: electrical and controls	$2.88 million	$12.00 million
Capital: pipeline (on-site)	$1.5 million	$7.2 million
Capital: utility interconnect	$2.0 million	$2.0 million
O&M: electricity	$1.7 million	$16.7 million
Construction and engineering: installation	$11.0 million	$50.3 million
Construction and engineering: owner's cost	$5.5 million	$25.1 million

ICF reports estimated levelized costs of RNG from thermal gasification of $19/MMBtu to $43/MMBtu.

Combined Supply-Cost Curve for RNG

ICF estimates that RNG will be available from various feedstocks in the range of less than $10/MMBtu to upwards of $70/MMBtu. Anaerobic digestion feedstocks, notably from LFG and WRRF, are more cost-effective in the short term. RNG from thermal gasification feedstocks are more expensive, largely reflecting the immature state of thermal gasification as a technology, and the associated uncertainties around cost and feedstock availability.

RNG is more expensive than its conventional counterpart; however, in a decarbonization framework, a more appropriate comparison for RNG is to other abatement measures that are viewed as long-term strategies to reduce GHG emissions (discussed in more detail in Section 6). In addition, ICF anticipates that over time there will be increasing opportunities for cost reductions as RNG technologies mature and the market expands.

The figures below show estimated supply-cost curves for RNG in Michigan in 2030 and in 2050, including resource potential for the Achievable Scenario (along the x-axis) and the estimated cost to deliver that RNG (along the y-axis). ICF notes that the supply-cost curves do not necessarily reflect the price for RNG available on the market today, but instead the estimated production costs for RNG as deployment escalates over time.

Both in 2030 and 2050 the front end of the supply curve is comprised of landfill gas and WRRFs, with limited thermal gasification potential in 2030, and relatively expensive. 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 $20-25/MMBtu in 2030. In 2050 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.

Figure 5-1. Combined Supply-Cost Curve for Michigan in 2030, Achievable ($/MMBtu)

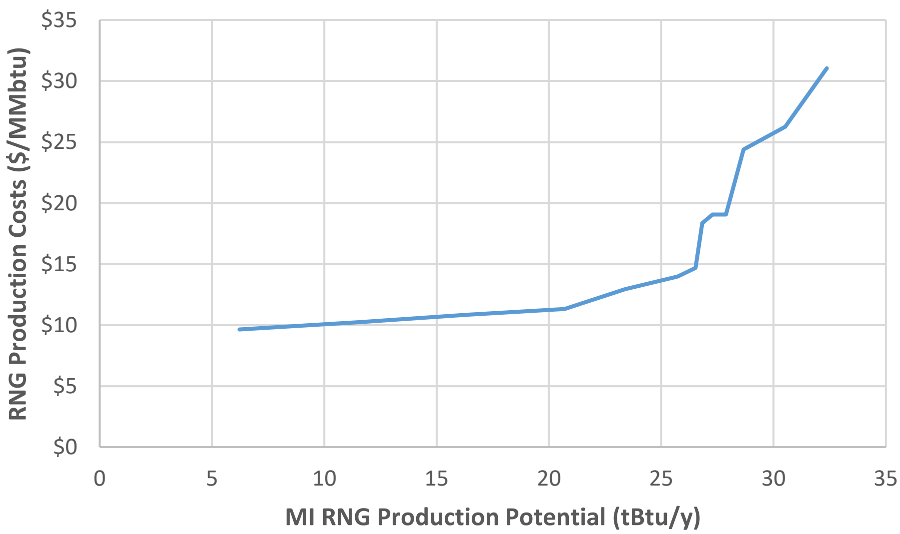
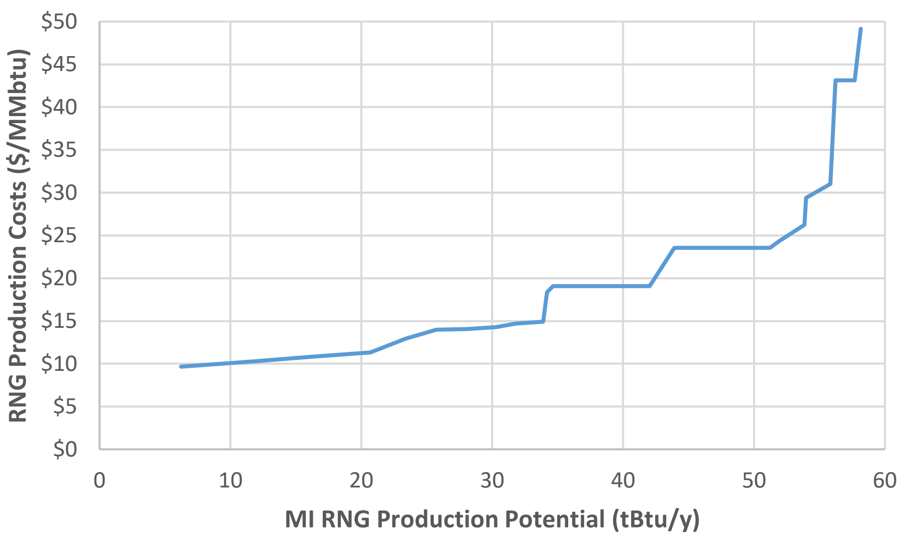


Figure 5-2. Combined Supply-Cost Curve for Michigan in 2050, Achievable ($/MMBtu)



6. GHG Emission Reductions and Cost-Effectiveness

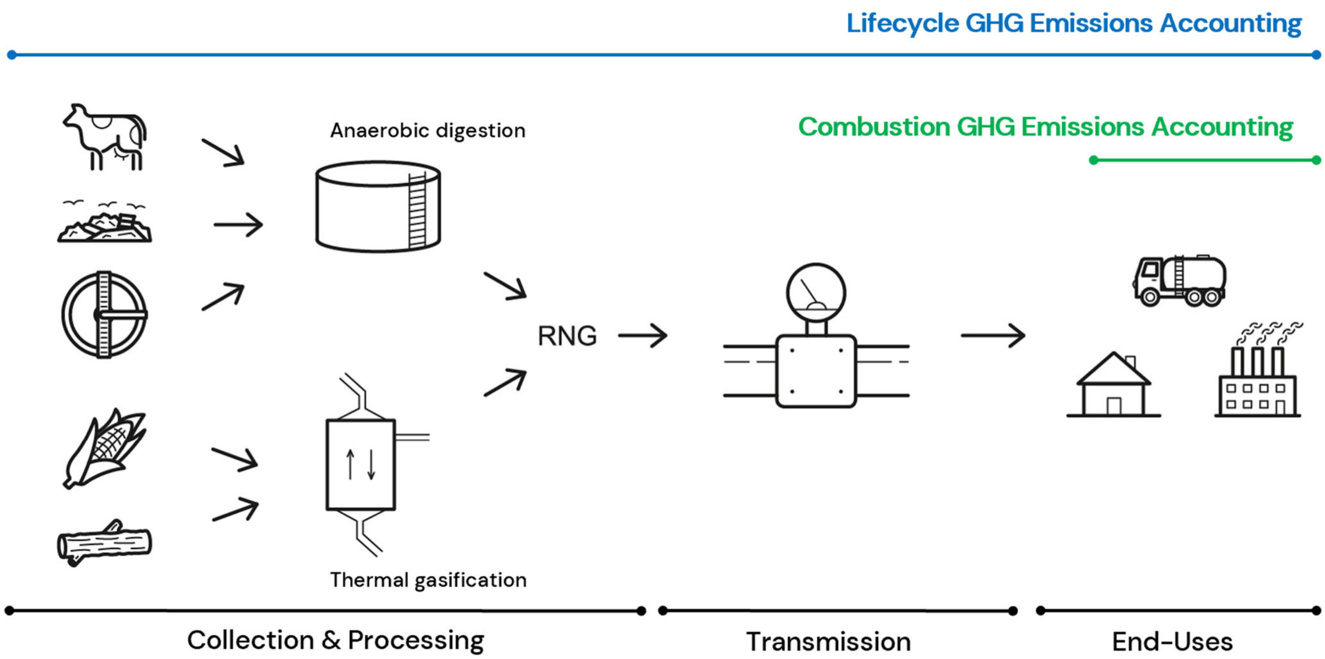
GHG emission accounting is a common practice used to evaluate the respective GHG impacts of various energy sources or fuels, and to enable comparison between them. GHG emission accounting is used in practice by regulators and private actors for a variety of reasons, including to develop GHG emission inventories, as part of broader environmental reports, and to track carbon as an environmental commodity in carbon markets. GHG emission accounting is applied in practice by multiplying a GHG emissions factor and the associated activity data for the fuel of interest. In other words, the total GHG emissions are calculated as a product of the emissions factor and the amount of energy consumed—the equation below highlights this for the case of natural gas, with the GHG emissions factor in units of kilograms of carbon dioxide equivalents per unit energy of natural gas, in units of million British thermal units ($kgCO_2e/MMBtu$) and the amount of natural gas used reported in units of MMBtu.

$$GHG\ Emissions = GHG\ Emissions\ Factor\ {}^{Lifecycle}_{Combustion} \left[\frac{kgCO_2e}{MMBtu}\right] \times\ Activity\ [MMBtu]$$

As noted in the equation above (as part of the *GHG Emissions Factor*), there are two distinct GHG emission accounting approaches in use today: the combustion approach and the lifecycle approach. The framework of these two approaches is consistent across fuel types. However, the inputs vary and lead to different GHG emission profiles. These two different GHG emission accounting approaches are currently driving the conversation regarding GHG emissions associated with RNG. It is important to understand that neither accounting approach is the "correct" one to use. Rather, the fact that both accounting approaches are used frequently can create confusion.

Figure 6-1 offers a more detailed view of the various stages in RNG production, showing two different production methods and multiple feedstocks. As shown below, the stages of the combustion and lifecycle accounting approaches are broken out into three categories: Collection & Processing, Pipeline/Transmission, and End-Uses. However, the inputs considered within these stages vary between conventional natural gas and RNG, and even among different RNG feedstocks.

Figure 6-1. Boundary Conditions of GHG Emission Account Approaches for RNG Production



GHG emissions from RNG can be generated along the three stages of the RNG supply chain.

- *Collection and processing: Energy use required to produce, process, and distribute the fuel*. The energy used to produce, process, and distribute RNG is characterized here as: 1) feedstock collection and 2) digestion and processing related to anaerobic digesters, or synthetic gas (syngas) processing as it relates to thermal gasification.
- *Pipeline/transmission: Methane leaks primarily during transmission*. Methane leaks can occur at all stages in the supply chain from production through use but are generally focused on leakage during transmission. ICF limits our explicit consideration to leaks of methane as those that occur during transmission through a natural gas pipeline, as other methane losses that occur during RNG production are captured as part of efficiency assumptions.
- *End-use: RNG combustion*. The GHG emissions attributable to RNG combustion are straightforward: CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or carbon neutral. In other words, the GHG emissions are limited to CH_4 and N_2O emissions because the CO_2 emissions are considered biogenic.[52]

For the purposes of this report, ICF has opted to present the GHG emission reductions here using the combustion approach, while providing an overview of the lifecycle GHG emission reductions attributable to RNG in Appendix B. The reasoning for this is straightforward: using the combustion approach enables ICF to compare the GHG emissions reductions attributable to the RNG supply scenarios developed for this study (see Section 4) to existing GHG emission inventories developed for Michigan. Furthermore, the combustion accounting approach enables

[52] IPCC guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas or biomass based RNG) should not be included when accounting for emissions in combustion – only CH_4 and N_2O are included. This is to avoid any upstream "double counting" of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance.

us to compare to the abatement cost of other strategies more accurately (see Section 7). More specifically, the abatement costs of other abatement strategies against which ICF is comparing RNG are uniformly reported using the combustion approach.

It is important to understand that ICF's presentation of results using the combustion approach is not an endorsement of one GHG emission accounting framework over another or a recommendation as it relates to a policy structure. Rather, it is an analytical and methodological decision to enable a more robust comparison and to contextualize the results of our analysis more accurately.

GHG Emissions from RNG Production Potential

ICF applied the aforementioned combustion accounting approach to estimate the GHG reduction potential across the two RNG potential scenarios for Michigan, as reported in Section 4.[53] ICF reiterates that a combustion GHG accounting framework is the standard approach for most volumetric GHG targets, developing GHG emissions inventories, and comparing mitigation measures as they are more closely tied to where the emissions physically occur. When applying the combustion approach, the emission reduction estimates for RNG consumption can be more easily compared to existing GHG emission inventories, such as Michigan's energy-related GHG emissions as shown in Figure 6-3. In particular, if RNG displaces conventional natural gas consumption in residential buildings, then the associated emission reductions can be directly attributed to the residential sector (in contrast to the lifecycle approach).

The figures below show the range of GHG emission reductions using a combustion accounting framework, in units of million metric tons of CO_2e ($MMtCO_2e$). ICF estimates that 3.0 to 7.9

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[53] Lifecycle GHG emission factors and emission reductions are discussed in

The combination of RINs and LCFS credits have helped deliver significant volumes of RNG, especially to California. In fact, as of the end of 2021, RNG accounted for more than 90% of the market for natural gas as a transportation fuel in California. As lower carbon RNG comes on to the market, end users will likely gain additional market influence. Most of the RNG that is currently delivered to and dispensed in California is derived from landfills. ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and digesters deployed at wastewater treatment plants.

Over time, these lower carbon sources will likely displace higher carbon intensity RNG from landfills. The role of RNG in the LCFS program will be determined by the market for NGVs. If steps are taken to foster adoption of NGVs, particularly in the heavy-duty sector(s), then this will be less of an issue. The introduction of the low-NOx engine (currently available as an 9L, 12L, and 6.7L engine) from Cummins may help jumpstart the market, especially with a near-term focus on NOx reductions in the South Coast Air Basin (which is in severe non-attainment for ozone standards).

$MMtCO_2e$ of emissions could be reduced per year by 2050 through the deployment of RNG projects located in Michigan, shown in Figure 6-2.

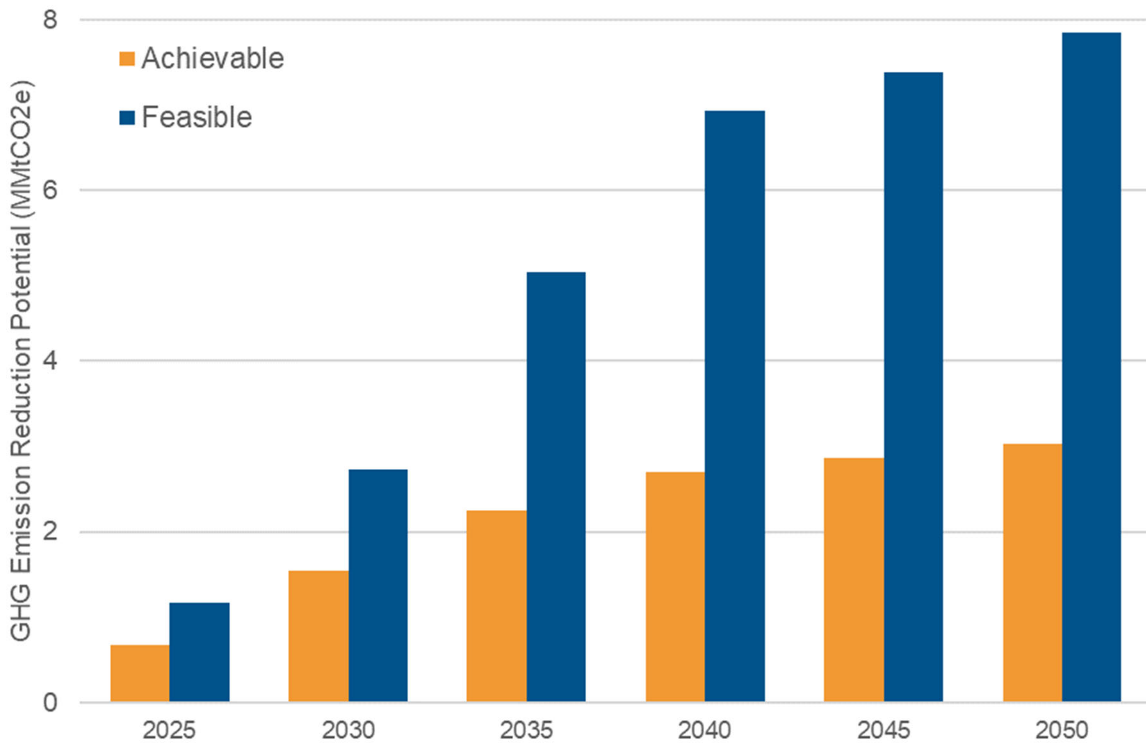
However, California has a clear focus on zero emission tailpipe solutions for the transportation sector e.g., via the Advanced Clean Truck (ACT) regulation. The ACT Regulation requires zero-emission purchase requirements for medium- and heavy-duty trucks starting in 2024. The rule seeks to "accelerate the widespread adoption of [ZEVs] in the medium- and heavy-duty truck sector." The core compliance mechanism is a minimum performance standard for ZEVs as a percentage of each major truck manufacturer's new sales in California.

While the deployment of RNG in the transportation sector has experienced massive growth in the past five years, there is a clear constraint to the overall production and use of RNG in transportation: the limited number of NGVs. With the transportation sector approaching RNG saturation, there is growing interest from policymakers, regulators and industry stakeholders to grow the production of RNG for pipeline injection and stationary end-use consumption.

As currently constructed, in general the policy framework does not encourage RNG use in stationary applications, instead directing RNG consumption to the transportation and electricity generation sectors. However, there are several emerging state-level policies in place that are helping to shape the outlook for RNG beyond transportation. The most interesting development for RNG is that there is growing interest in applying the same principles of RPS program as it relates to electricity to the natural gas sector. These are often referred to as Renewable Gas Standards. Oregon's Senate Bill 98 (SB 98), for instance, established a voluntary goal for adding as much as 30% RNG into Oregon's system by 2050. Furthermore, the law allows up to 5% of a utility's revenue requirement to be used to cover the additional cost of investments in RNG infrastructure. More specifically, the bill operates similar to a renewable portfolio standard, whereby volumetric goals have been set, and other critical parameters have been established to support cost-effective procurement. Utilities are able to invest in and own the processing and conditioning equipment required to upgrade raw biogas to pipeline quality gas, as well as the interconnection facilities to connect to the local gas distribution system. To date, NW Natural in Oregon has executed two agreements that will deliver about 2% of NW Natural's annual sales in Oregon, including agreements with a) Tyson Foods and BioCarbN to convert waste to RNG at Tyson facilities and b) Element Markets to purchase the environmental attributes from a WRRF in New York City and a mixed waste anaerobic digester in Wisconsin.

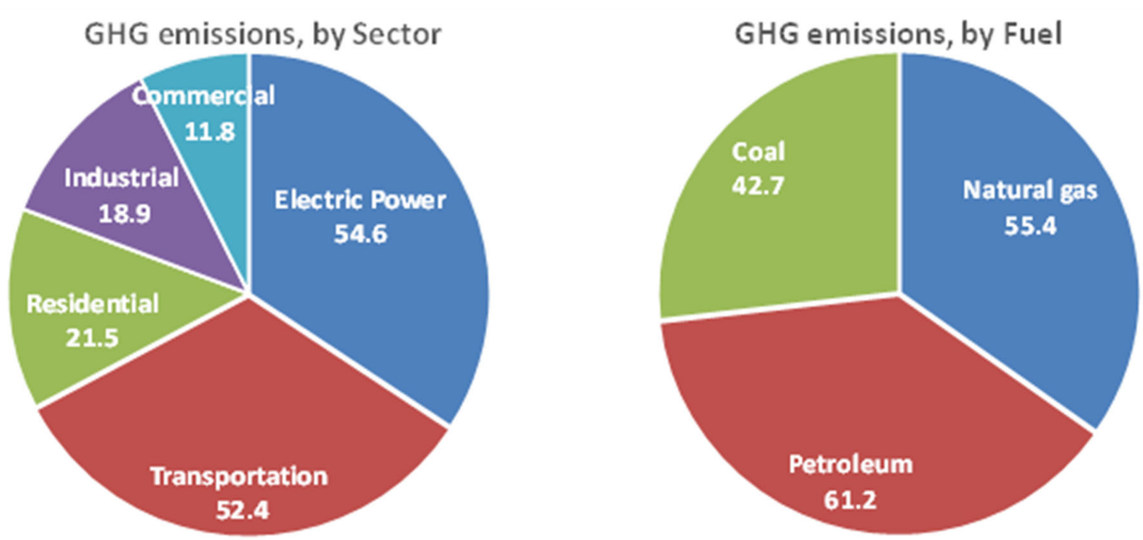
Appendix B.

Figure 6-2. Michigan RNG Emission Reduction Potential by Scenario (MMtCO$_2$e)



Michigan's energy-related CO_2 emissions were 159 MMtCO$_2$e in 2019, shown below by sector and fuel in Figure 6-3 below.[54]

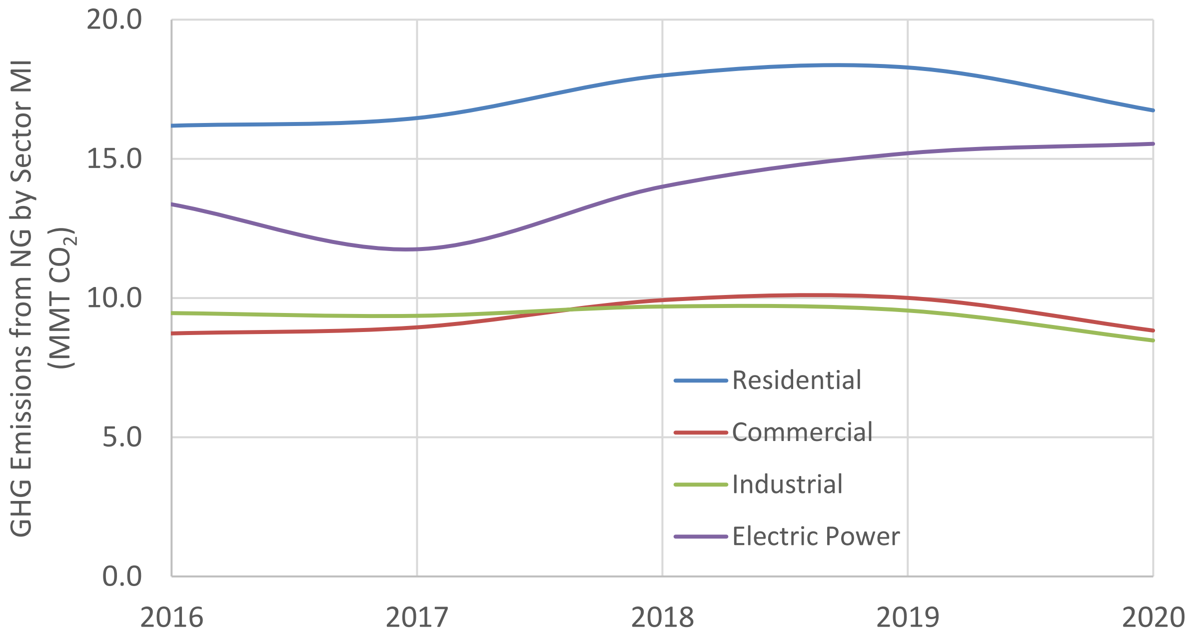
Figure 6-3. Michigan Energy-Related CO_2 Emissions, 2019 (MMtCO$_2$e)



[54] U.S. Energy Information Agency, 2022. State energy-related carbon dioxide emissions by sector and fuel, https://www.eia.gov/environment/emissions/state/.

Because RNG is more expensive than conventional natural gas and because we generally assume that there will be a focus on energy efficiency across all sectors, ICF assumes that RNG will most likely to displace conventional natural gas consumption, as opposed to increasing natural gas consumption as a result of displacing another fuel like petroleum or coal. Natural gas currently accounts for about 35% of Michigan's energy-related carbon dioxide emissions. Natural gas is consumed across four main sectors: residential, commercial, industrial, and for electric power generation.[55] The plot below shows the GHG emissions attributable to natural gas consumption in these four sectors from 2016 to 2020 based on data from the EIA [56] and analysis by ICF.

Figure 6-4. GHG Emissions from Natural Gas Consumption by Sector in Michigan



[55] Natural gas is also consumed as a transportation fuel in Michigan, but it represents less than 0.1% of total consumption statewide.
[56] Natural Gas Consumption by End Use, US EIA. Available online at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SMI_a.htm.

It is unlikely that RNG will be used to displace fossil natural gas in the electric power generation sector because that pathway will be more expensive than electric power generation from other resources. For instance, the EIA recently estimated that the LCOE of electricity produced from combined cycle power plants powered by natural gas would be about $37 per megawatt hour (MWh) in 2027, and that about $26/MWh of this cost was attributable to the variable cost, which is primarily attributable to natural gas costs. Comparatively, wind and solar electricity generation would have a LCOE of $33-38/MWh.[57] RNG would cause the variable costs of natural gas fired combined cycle plants to more than double, increasing the LCOE by at least 70%. In other words, there are likely to be more cost-effective uses of RNG than in decarbonizing electricity generation. As such, ICF focuses on the other three end uses shown in the graph above: residential, commercial, and industrial. Although RNG will be more expensive than natural gas, it will be more cost competitive with other decarbonization opportunities in these sectors, as discussed in more detail in Section 7.

The trends shown in the figure above show that average annual GHG emissions from natural gas consumption in these three sectors is about 36 MMtCO_2e. In other words, if RNG was used to displace conventional gas in these three sectors, it could decrease GHG emissions in these sectors by 8% to 21% based on current levels of consumption. ICF also notes that as efficiency improvements and other market forces that decrease the demand for natural gas in these sectors take hold, the role of RNG will be increasingly important. Consider for instance a 15% decrease from today's levels of natural gas consumption over the same period that it takes to develop the RNG supply potential that ICF developed for the Achievable and Feasible scenarios. This would mean that RNG would decrease GHG emissions by 10% to 26% when paired with efficiency gains and/or other measures that decrease natural gas consumption.

RNG and Decarbonization

As shown by the cost estimates provided in Section 5, RNG costs more than conventional natural gas, when environmental benefits are not fully valued. However, the objective for enhanced RNG production and deployment is not to be cost-competitive to conventional natural gas on a dollars-per-MMBtu basis.

Instead, the benefit of RNG is derived from the valuable environmental attributes associated with RNG, and the GHG emission reductions when RNG displaces conventional natural gas consumption. Outside of the transportation sector, these positive environmental attributes are not currently credited, indicating a policy and regulatory framework that does not effectively value the role of RNG.

With the commitment to deep and long-term decarbonization objectives, including in Michigan, strategies and policies will need to be implemented to deliver on these ambitious goals. In contrast to the current regulatory structure, in a decarbonization framework RNG is a renewable resource with carbon-neutral (and in some cases, carbon-negative) characteristics, and the GHG emissions from RNG are lower than conventional natural gas across the board.

[57] EIA, Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022. Available online at https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. Values are shown in 2021 dollars per MWh.

To assess the cost-effectiveness of RNG as a GHG emission reduction measure, the relevant metric is not the commodity cost in dollars-per-MMBtu but instead GHG abatement costs. Abatement costs are measured in dollars-per-unit of GHG emission reductions, typically metric tons of carbon dioxide equivalent ($/t$CO_2$e). Estimating and comparing the cost-effectiveness of different GHG emission reduction measures is challenging and results can vary significantly across temporal and geographic considerations.

RNG Cost-Effectiveness

The GHG cost-effectiveness is reported on a dollar-per-ton basis and is calculated as the difference between the emissions attributable to RNG and conventional natural gas. For this report, ICF followed IPCC guidelines and does not include biogenic emissions of CO_2 from RNG. The cost-effectiveness calculation is simply as follows:

$$\Delta(RNG_{cost}, Fossil\ NG_{cost}) / 0.05306\ MT\ CO_{2e}$$

where the RNG_{cost} is simply the cost from the estimates reported previously. For the purposes of this report, we use a conventional natural gas cost equal to the three-year rolling average Henry Hub spot price reported by the EIA for years 2019 to 2021,[58] adjusted for inflation to dollars in 2022 ($2022) and calculated as $3.11/MMBtu. ICF notes that the average spot price of natural gas via Henry Hub through April 2022 has averaged about $5.14/MMBtu or 1.65 times higher than the three-year rolling average considered in this report. If these higher prices were to persist, then it would *decrease* the abatement cost of RNG as a replacement for conventional gas in real terms, and likely the relative abatement costs of non-gas alternatives.

The front end of the supply-cost curve is showing RNG of less than $10/MMBtu, which is equivalent to about $130 per metric ton of carbon dioxide equivalent (tCO_2e). As the estimated RNG cost increases to $25/MMBtu, we report an estimated cost-effectiveness of above $400/t$CO_2$e. This range in cost for RNG can be converted to provide an equivalent range for the cost-effectiveness of RNG for GHG emission reductions, in dollars per tCO_2e.

Summary of GHG Emission Reductions from RNG Supply Scenarios

When applying a combustion accounting framework and treating CO_2 emissions from the combustion of biogenic renewable fuels as zero, ICF estimates that 3 to 9 MMtCO_2e of GHG emissions could be reduced per year in 2050 in Michigan through the deployment of RNG based on the Achievable and Feasible scenarios. For abatement cost estimates, RNG at under $10/MMBtu is equivalent to about $130/t$CO_2$e, while RNG at $20/MMBtu has an estimated cost-effectiveness of about $300/t$CO_2$e.

[58] EIA, Natural Gas Data, available online at https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm

The GHG emission reduction potential for RNG is best understood in the context of cost-effectiveness or in units of dollars per ton of emissions reduced. The reasoning is simple: absent unexpected cost reductions in RNG production technology, there will always be a potential “sticker shock” associated with RNG when framed using traditional metrics like dollars per unit energy (e.g., $/MMBtu). However, the cost-effectiveness of RNG deployment is a better metric to contextualize the opportunities for and barriers to broader RNG deployment as part of deep decarbonization considerations.

7. GHG Abatement Cost Comparison

As outlined in the previous section, the first step to evaluate the cost effectiveness of a GHG emission reduction measure is to estimate the abatement cost in a translatable metric, such as $/t$CO_2$e. The second component is to compare the dollar-per-ton estimates outlined in the previous section with other GHG emission reduction measures. ICF notes that estimating the cost-effectiveness of different GHG emission reduction measures is challenging and results can vary significantly across temporal and geographic considerations.

ICF also notes that the intent of this study is not to develop new analysis and modeling that estimates abatement costs for emission reduction measures beyond RNG, such as residential electrification and renewable hydrogen. Instead, the objective is to compare the RNG abatement cost range developed in this study to the costs of other abatement measures sourced from existing research and studies.

The abatement measures within scope for cost comparison are organized into four groups:

- Renewable hydrogen blending;
- Building electrification;
- Electricity generation; and
- Transportation electrification.

Below is a summary table of the estimated abatement cost ranges for the four groupings of abatement measures, as well as the underlying source analyses for the abatement cost ranges. The following subsections provide a brief description of each analysis.

Table 7-1. Summary of Abatement Costs for Emission Reduction Measures

Emission Reduction Measure	Abatement Cost ($/t$CO_2$e)	
	Low	High
RNG (this study)	**$132**	**$510**
Renewable Hydrogen Blending Range	**$183**	**$296**
ICF Production Cost Estimates in 2050	$183	$296
Comparisons (Columbia Center on Global Energy Policy and US DOE)	$85	$791
Building Electrification Range	**$0**	**$1,000**
Pennsylvania Climate Action Plan[59]	-	$502
University of Texas, Carnegie Mellon & University of Michigan[60]	$0	$1,000
Electricity Generation	**$69**	**$446**
E3: PJM 80-100% RPS 2050 (2020)[61]	$69	$220
EFI & E3: New England Net Zero (2020)[62]	-	$446
Transportation Electrification	**$135**	**$599**
ICF Comparison of Medium and Heavy-Duty Truck Technologies[63]	$135	$400
E3: Deep Decarbonization in a High Renewables Future[64]	$359	$599

[59] Pennsylvania Department of Environmental Protection, 2021. Pennsylvania Climate Action Plan, https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx

[60] Thomas A Deetjen *et al* 2021 *Environ. Res. Lett.* 16 084024. US residential heat pumps: the private economic potential and its emissions, health, and grid impacts, https://iopscience.iop.org/article/10.1088/1748-9326/ac10dc#erlac10dcs6.

[61] E3, 2020. Least Cost Carbon Reduction Policies in PJM, https://www.ethree.com/least-cost-carbon-reduction-in-pjm/.

[62] E3 and EFI, 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future, https://www.ethree.com/new-study-evaluates-deep-decarbonization-pathways-in-new-england/.

[63] ICF updated analysis of Comparison of Medium- and Heavy-Duty Technologies in California. Available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=236878.

[64] California Energy Commission, 2018. Deep Decarbonization in a High Renewables Future, https://www.energy.ca.gov/publications/2018/deep-decarbonization-high-renewables-future-updated-results-california-pathways.

Renewable Hydrogen Blending

Renewable hydrogen (or "green hydrogen") in the context of this report refers to hydrogen generated from electrolysis using renewable electricity, also referred to as power-to-gas (P2G). The key process in P2G is the production of hydrogen from renewably generated electricity by means of electrolysis. Electrolyzers split water into hydrogen and oxygen, where if the electricity is sourced from renewable resources, such as wind and solar, then the resulting hydrogen is carbon neutral.

This hydrogen conversion method is not new, and there are three electrolysis technologies with different efficiencies and in different stages of development and implementation:

- Alkaline electrolysis, where two electrodes operate in a liquid alkaline solution,
- Proton exchange membrane electrolysis, where a solid membrane conducts protons and separates gases in a fuel cell, and
- Solid oxide electrolysis, a fuel cell that uses a solid oxide at high temperatures.

The hydrogen produced from P2G is a highly flexible energy product that can be:

- Stored as hydrogen and used to generate electricity at a later time using fuel cells or conventional generating technologies,
- Injected as hydrogen into the natural gas system, where it augments the natural gas supply,
- Converted to methane and injected into the natural gas system, or
- Injected into a dedicated hydrogen pipeline.

Noting the different uses for hydrogen outlined above, for this abatement cost comparison we have limited the consideration of renewable hydrogen to volumes that can be mixed directly with natural gas in existing pipeline systems without changes to infrastructure or end-use equipment. The blend limit of hydrogen in existing natural gas distribution systems is an evolving area of research and analysis, and can vary depending on the physical characteristics of the system as well as end use appliances. Despite this uncertainty, there are indications that hydrogen can be blended up to 20 percent by volume (7 percent by weight) without adverse effects to existing gas infrastructure and without significant upgrades.[65]

Based on this approach, the costs associated with the deployment of renewable hydrogen as an emission reduction measure are limited to the production cost of the hydrogen itself. ICF developed hydrogen production costs using a series of assumptions regarding the following key parameters: a) electrolyzer costs and efficiency, b) the cost of renewable electricity as a function of how it is delivered to the electrolyzer (e.g., via curtailed renewable electricity or dedicated renewable electricity), and c) the capacity factor for P2G systems.

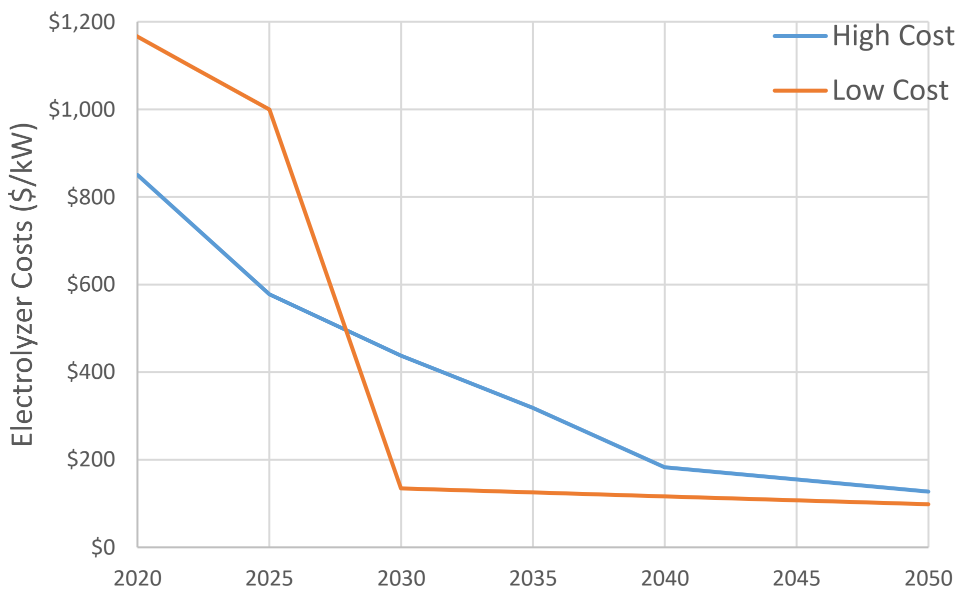
Electrolyzer Costs and Efficiency

ICF developed the installed cost of electrolyzers on a dollar per kilowatt ($/kW) basis. The graph below illustrates ICF's assumptions regarding the installed costs of electrolyzers; we assumed

[65] California Energy Commission, 2021. 2021 Integrated Energy Policy Report Volume III: Decarbonizing the State's Gas System, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report.

that the resource base for electrolyzers would be some blend of proton exchange membrane (PEM), alkaline systems, and solid oxide systems. Rather than be deterministic about which technology will be the preferred technology, we present the cost as a blended average of the $/kW installed. This is based on ICF's review of literature and review of assumptions developed by UC Irvine[66] and by Bloomberg New Energy Finance (BNEF).[67] Using this approach, ICF's estimates an electrolyzer cost in the range of $98/kW to $127.50/kW in 2050, shown in the figure below.

Figure 7-1. Installed Capacity Cost of Electrolyzers, $/kW, 2020-2050



ICF assumed improved efficiencies over time for electrolyzers consistent with the values presented in the figure below. The peak efficiency of 77% by 2050 is consistent with estimates reported by UC Irvine and BNEF.

Cost of Renewable Electricity

The levelized cost of renewable electricity is a critical parameter in the determination of the levelized cost of renewable hydrogen production. BNEF, for instance, recently reported renewable hydrogen costs based on an assumed LCOE for renewable electricity in the range of $15-20/MWh. ICF took a more nuanced view of LCOE of renewable electricity in this analysis, considering regional considerations and data from the National Renewable Energy Laboratory (NREL).

In our consideration of curtailed renewable electricity, ICF assumes that the cost would be around $40-45/MWh to cover the costs of transmission and distribution of the electricity, but that the commodity cost would be zero.

[66] The Challenge of Retail Gas in California's Low-Carbon Future, CEC-500-2019-055-F, available online at https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf.
[67] Hydrogen Levelized Cost Update 2021, Bloomberg New Energy Finance, Confidential.

To develop hydrogen production costs from dedicated renewables, ICF used 2021 LCOE and capacity factor estimates from NREL's Advanced Technology Baseline (ATB) data. More specifically, ICF assumed that electrolyzers used to produce green hydrogen would be powered by a mix of dedicated renewable electricity installations, including from off-shore wind, land-based wind, and utility scale solar PV.

Although curtailed renewable electricity is likely to be inexpensive, it will only be intermittently available based on supply-demand dynamics in the electricity sector. ICF made the assumption that curtailed renewable electricity will enable an electrolyzer system to operate at a maximum 10% annual capacity factor. Conversely, ICF assumed that by 2050 dedicated renewable electricity systems will be able to operate at a weighted average annual capacity factor consistent with the values reported in NREL's ATB 2021. Using these assumptions, dedicated renewables lead to better economics than curtailed renewables, and so all modeling cases assumed dedicated renewables.

To determine a low-end abatement cost for renewable hydrogen, ICF used low cost estimates for electrolyzers, the lower costs for LCOE and higher capacity estimates in our sensitivity analysis from NREL's ATB 2021. The low-end production cost for renewable hydrogen is estimated at $11.35/MMBtu or $1.70/kg in 2050.

To determine a high-end abatement cost for renewable hydrogen, ICF used high cost estimates for electrolyzers, the more conservative estimates for LCOE and capacity factors of renewable electricity from NREL's ATB 2021. The high-end production cost for renewable hydrogen is estimated at $16.78/MMBtu or $2.51/kg in 2050.

ICF's estimated costs of renewable hydrogen yield a GHG abatement cost of \$155/tCO_2e to \$258/tCO_2e in 2050.

Comparable References

The Columbia Center on Global Energy Policy estimates that the current production cost for renewable hydrogen is $6.04/kg using grid renewables, and as a high as $8.30/kg for production facilities using dedicated renewables.[68] Unlike ICF's analysis, the Columbia Center on Global Energy Policy developed the analysis based on current capital and electricity cost estimates and they did not take into account any cost reductions in the future. For instance, the U.S. Department of Energy Hydrogen Shot outlines a pathway to reduce the cost of renewable hydrogen to $1.00/kg through reductions in three crucial cost areas: input renewable electricity, capital, and operating and maintenance.[69] However, the Columbia Center on Global Energy Policy does not assume any cost reductions.

Building Electrification

Building electrification describes the strategy of shifting to use electricity for building energy uses like space heating and cooking. The biggest focus tends to be on heat pumps. In

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[68] Columbia Center on Global Energy Policy, 2019. Low-Carbon Heat Solutions for Heavy Industry: Sources, Options and Costs Today, https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/LowCarbonHeat-CGEP_Report_100219-2_0.pdf.
[69] U.S. DOE Hydrogen Shot, 2021. https://www.energy.gov/eere/fuelcells/hydrogen-shot.

residential and commercial buildings, appliances powered by natural gas, propane, or heating oil powered appliances (e.g., furnaces and boilers) are assumed to be ground- or air-source heat pumps. Similarly, gas-powered heaters can be replaced with heat pump water heaters. Furthermore, kitchen appliances running on natural gas can be replaced with electric ranges and induction stove tops.

Determining the impact of building electrification (e.g., via costs and GHG emissions) relies on assumptions and sophisticated analysis regarding how renewable electrons are delivered on an as-needed basis (i.e., dispatched) to align electricity demand with renewable electricity generation.

To estimate abatement levels and the associated costs of building electrification, any analysis would need to include appliance and equipment costs, installation costs, maintenance costs, fuel costs (including electric system costs) and conversion or retrofit costs. Focusing on a subset of these costs, such as a comparison of upfront appliance costs, would not deliver a robust and complete picture of the costs and benefits of building electrification.

As noted at the start of this subsection, estimating the cost-effectiveness of emission reduction measures is challenging and results can vary significantly. Building electrification, and residential building electrification in particular, showcases this variability, with temporal and geographic considerations, combined with modeling assumptions and limitations, delivering a wide range of abatement cost estimates.

For example, a core component of building electrification is the deployment of heat pumps for space heating and cooling. Heat pumps operate as reversible air conditioners, in that they act as air conditioners in summer, and reverse the flow in winter to become heaters. In winter heat pumps absorb heat from outdoors and release it inside the building, with electricity used to do the mechanical work to move heat (rather than produce heat).

Heat pump adoption has the potential to significantly increase peak electricity demand and shift the seasonal timing of peak demand (such as from summer to winter). The operation of heat pumps is also impacted by climate and temperature, as they are less efficient and consume more energy in colder environments, exacerbating electricity demand issues as well as operation costs. For example, the Rocky Mountain Institute found that the coefficient of performance for heat pumps declined from 3.5 at 47°F to 1.4 at –13°F in Illinois and Rhode Island.[70]

In comments submitted to MPSC, stakeholders noted a variety of key factors associated with incorporating heat pumps into any building electrification analysis. For instance, one stakeholder requested that to reflect Michigan's climate, any building electrification comparison should use cold climate air source heat pumps (ccASHPs) that have higher efficiency ratings and may provide greater efficiency gains than their relative difference in Heating Season Performance Factor (HSPF) ratings. ICF notes that the two studies that are described in more detail below do not focus on ccASHPs.

[70] Rocky Mountain Institute, 2018. The Economics of Electrifying Buildings, https://rmi.org/insight/the-economics-of-electrifying-buildings/.

To ensure consistency with the abatement cost estimates for RNG and other measures, building electrification abatement costs used for comparison in this study need to incorporate input assumptions broadly consistent with the geography and climate of Michigan in the absence of any Michigan-specific data. The first study discussed below covers a broad range of geographies whereas the latter is focused on Pennsylvania.[71]

University of Texas, Carnegie Mellon & University of Michigan

Researchers from the University of Texas, Carnegie Mellon and University of Michigan simulated energy consumption of 400 representative single-family houses in 55 US cities both before and after heat pump adoption in an attempt to estimate the costs and benefits of increased heat pump adoption, taking into account housing stock, electric grid, energy prices, and technology.[72] ICF finds this study particularly helpful in emphasizing the significant variance in electrification costs, and associated abatement costs.

The study includes energy prices, CO_2 emissions, health damages from criteria air pollutants, and changes in peak electricity demand to quantify the costs and benefits of each house's heat pump retrofit. Cumulative costs and benefits are based on the typical life time of a heat pump, assumed to be 15 years. These costs and benefits are adjusted over this time period to account for relevant trends, such as declining emissions from the electric grid.

At a high level, the study found that roughly 20% of residential US housing stock would benefit economically by replacing existing heating with a heat pump. However, the study recognizes that climate is crucial to realizing the economic benefit of heat pump adoption, with mild climates demonstrating the greatest potential for this switch. In addition, the study found that "switching a home's heating fuel from natural gas to heat pumps rarely produces a benefit, especially in cold climates where there are almost no houses where such a switch makes sense".

The results of the study do not specifically present detailed abatement costs across climates and housing types. However, the research notes:

- 28% of US residential housing stock have abatement costs in the range of \$0/tCO_2e to \$200/tCO_2e.
- 66% of US residential housing stock have abatement costs in the range of \$200/tCO_2e to \$1,000/tCO_2e.
- 6% of US residential housing stock have abatement costs exceeding \$1,000/tCO_2e.

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[71] ICF notes that there are studies available in the public domain that may seem relevant at first glance. For instance, ICF reviewed the *Massachusetts 2050 Decarbonization Roadmap*. That study's section on building electrification implies that building electrification has a *negative* cost per ton of emission reduction for most buildings (which implies that society yields a net benefit, not a net cost). However, this study exemplifies the challenge comparing across abatement strategies in a consistent manner. ICF ultimately excluded the study from this report because it does *not* provide an adequate estimate for building electrification. More specifically, the abatement cost estimates are limited to capital costs associated with building electrification, and *do not* include other costs such as fuel and system-wide investments required to accommodate the electrification envisioned in the study.

[72] Deetjen et al, 2021. Environmental Research Letters, 16-084024, US residential heat pumps: the private economic potential and its emissions, health, and grid impacts, https://iopscience.iop.org/article/10.1088/1748-9326/ac10dc#erlac10dcs6.

Pennsylvania Climate Action Plan

Pennsylvania's 2021 Climate Action Plan (PA-CAP)[73] outlines a pathway to reach Pennsylvania's GHG reduction goal of 80 percent by 2050 from 2005 levels. The economy-wide plan includes modeling and analysis of 18 different emission reduction strategies, including a detailed assessment of residential and commercial electrification. This electrification strategy includes incentivizing building electrification (e.g., heating and hot water) for the residential and commercial sectors, inclusive of converting fuel oil and natural gas use to electricity use in existing buildings and electrification of new buildings when there are large natural gas infrastructure costs or when fuel oil is the alternative.

The PA-CAP methodology involved an average annual energy savings potential for new and existing residential and commercial buildings to estimate energy consumption (natural gas, and fuel oil) reductions from electrification. GHG emission factors for electricity were consistent with the decarbonization of Pennsylvania's consumption to meet the 80 percent reduction target. The natural gas emissions factor reflected the PA-CAP's modeled deployment of RNG over time. Electrification conversion factors assumed a Heating Seasonal Performance Factor for residential single family and multifamily of 8.2. Electrification of commercial sector included a 18% efficiency electrification factor taken from American Council for an Energy Efficiency Economy's "Electrifying Space Heating in Existing Commercial Buildings" study. Since electrification and cold climate heat pumps are still early technology, a 1% annual improvement curve for capital costs and associated incentives was included in alignment with air source heat pump projections from NREL's "Electrification Future's Study".[74]

While the weather and climate conditions of Pennsylvania and Michigan are not identical, ICF considers that there are enough similarities in climate, and subsequent operation of electric space heating appliances, to allow for a reasonable comparison of electrification abatement costs. This is contrast to other studies of electrification measures with climate conditions distinct from Michigan, such as in California.[75] Furthermore, electric rates in Michigan and Pennsylvania are comparable, with Michigan's average price of electricity across all sectors just 16-17% higher than for Pennsylvania.[76]

The PA-CAP outlines emission reductions, in tCO_2e, and costs, in 2021$, for the suite of building electrification incentive programs included in the pathway out to 2050. From these figures the abatement cost is estimated at $502/$tCO_2e$.

[73] Pennsylvania Department of Environmental Protection, 2021. Pennsylvania Climate Action Plan, https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx.
[74] National Renewable Energy Laboratory (NREL), 2017. Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050, https://www.nrel.gov/docs/fy18osti/70485.pdf.
[75] For example, abatement cost estimates included in Energy Futures Initiative's Deep Decarbonization Pathways for California is not considered pertinent given the generally different climates of California and Michigan.
[76] Based on ICF analysis of data from the Electric Power Monthly, published by the EIA, available online at https://www.eia.gov/electricity/monthly/.

Electricity Generation

The decarbonization of electricity generation encompasses a significant number of different emission reduction measures, with a large scope of measures that can be narrow, such as a single renewable electricity project, or broad, including jurisdictional emission reduction targets for electricity grids.

As noted previously, the RNG market is transitioning away from biogas to electricity projects and towards pipeline injection in part because it is not as cost-effective to generate electricity using biogas as other renewable resources. For instance, the table below is reproduced from a Waste to Energy from Municipal Solid Waste Report prepared for the DOE in 2019, and shows selected project costs of electricity in cents per kilowatt-hour, including for biogas to electricity projects.[77]

Solar PV	Onshore Wind	Offshore Wind	Natural gas, Combined Cycle	Natural gas, Combustion Turbine	Conventional Coal	Biogas
6.3	5.9	13.8	4.9	9.9	10.3	8.2-19.6

The authors conclude that “based on the limited amount of techno-economic analysis that is publicly available, MSW or biomass-based power generation can be among the most expensive options for producing electricity.”

Although not included in the table above, ICF notes that LCOE of electricity generation from nuclear power is reported in the range of 4.39 to 9.86 c/kwh depending on the discount rate employed for plants built in the 2020 to 2025 timeframe.[78]

The table above also highlights why there is such a strong focus on decarbonizing electricity generation using renewables like solar photovoltaics (PV) and wind: Their costs are competitive today with conventional alternatives and are projected to decrease over time.

New England Net-Zero

E3 and EFI conducted a detailed analysis of New England’s electricity system’s reliability in the context of reducing emissions to nearly zero. They found that meeting this dual challenge cost-effectively will involve the addition of large amounts of wind, solar, and battery storage resources, complemented by firm capacity to provide generation during extended periods of low wind and solar availability—including natural gas power plants, nuclear, hydrogen generation, or other yet-to-be commercialized options such as long-duration storage.

Under the High Electrification Scenario, E3 and EFI report marginal abatement costs relative to a reference case scenario—and that reference case scenario assumes a 50% RPS. In other words, the marginal cost is the difference between achieving a net zero emissions target compared to the GHG emissions in a 50% RPS scenario. For the sake of reference, the New

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[77] DOE, Office of Energy Efficiency and Renewable Energy, Waste-to-Energy from Municipal Solid Wastes, August 2019. https://www.energy.gov/sites/prod/files/2019/08/f66/BETO--Waste-to-Energy-Report-August--2019.pdf.

[78] OECD IEA & NEA, Projected Costs of Generating Electricity, 2020 Edition, Table 3.13a, assuming 85% capacity factor and discount rates of 3% to 10%.

England states considered in the E3 and EFI analysis emitted about 170 $MMtCO_2e$ in 2016. The marginal cost of abatement of reducing GHG emissions in the High Electrification scenario to 10 $MMtCO_2e$ in 2050 was about $125/$tCO_2e$; however, reducing it to 2.5 $MMtCO_2e$ and then 0 $MMtCO_2e$ in 2050 showed a marginal abatement cost of $442/$tCO_2e$ and $446/$tCO_2e$, respectively. Importantly, the E3 and EFI analysis assumed in their High Electrification Scenario that renewable hydrogen would be available in lieu of conventional natural gas molecules for electricity generation. To achieve net zero emissions without any combustion of gaseous renewable hydrogen and relying exclusively on renewable electricity and storage would increase the marginal abatement cost to nearly $8,000/$tCO_2e$.

Least Cost Carbon Reduction Policies in PJM

E3 evaluated least cost carbon reduction policies in the PJM region in a “least-cost, least-regrets manner.” The analysis was built around different policies that would achieve decarbonization targets. By 2050, E3 reports a range of $23-77/$tCO_2e$ associated with grid decarbonization. The variation in the average abatement cost is a function of the policy. For instance, E3 report that achieving an 80% RPS for the PJM region would have an average cost of about $69/$tCO_2e$ whereas a program designed to achieve 80% GHG emission reductions is more cost-effective at $23/$tCO_2e$. However, the lower costs in the GHG emission reduction scenario are achieved through a policy that encourages more-efficient, lower-emissions resources to replace less-efficient, higher-emitting ones (e.g., switching from coal to gas). Furthermore, the GHG emission reduction scenario enables gas power generators to use drop-in biofuels in later years. As a result of the focus on GHG emission reductions, rather than renewable electricity deployment, the GHG reduction scenarios build less renewable capacity compared to the 80% RPS case, retire the coal fleet by 2030, and keep nuclear capacity online to meet the GHG targets.

ICF limited the extraction of abatement costs to the scenarios that are tied to renewable energy production via the RPS cases, focusing on the 80% and 100% RPS cases presented in the analysis. For the 80% RPS case, E3 reports an average abatement cost of about $69/$tCO_2e$; ICF estimates that the average abatement cost for the 100% RPS case is closer to $220/$tCO_2e$. ICF also notes that there are average abatement costs reported, and not marginal abatement costs—at the margin, the abatement costs are closer to $500/$tCO_2e$ based on ICF’s analysis of data presented in the study.

Transportation Electrification

Transportation electrification is a set of broad emission reduction measures encompassing all forms of transportation, from light-, medium- and heavy-duty vehicles through to off-road transportation types including rail. With this wide-ranging grouping, the emission reduction potential and associated costs of specific types of electrification can vary significantly.

To deliver a more targeted abatement cost comparison relevant to RNG, ICF will limit the consideration of transportation electrification types where RNG is or has the potential to be a cost-effective emission reduction measure, focused on medium- and heavy-duty vehicles (M&HDVs). RNG is already a viable option to decarbonize M&HDVs, with established vehicle technologies and pathways for RNG to be used as a transportation fuel.

In contrast to building electrification, the abatement costs associated with the electrification of M&HDVs are relatively consistent across geographies and climate (notwithstanding changes in battery efficiencies across temperatures). For this reason, transportation electrification studies and analyses considered for abatement cost comparison do not necessarily need to be Michigan specific.

ICF notes that transportation electrification and RNG are unlikely to be "competitors" or "alternatives" in Michigan in the mid- to long-term future. To be clear, RNG is not a substitute for gasoline. Rather, most RNG is used in compressed natural gas (CNG) vehicles in the medium- and heavy-duty market segments (e.g., transit buses, refuse haulers, regional haul trucks, etc.). By way of background, CNG is not consumed in significant volumes in Michigan. There are fewer than 25 CNG stations in Michigan and ICF estimates that the estimated annual consumption of CNG is about 3 to 5 million diesel gallon equivalents (DGE). Comparatively, there are about 1 billion gallons of diesel and 4.5 billion gallons of gasoline consumed in Michigan.

ICF's Comparison of Medium- and Heavy-Duty Technologies

ICF was contracted by the California Electric Transportation Coalition and the Natural Resources Defense Council (NRDC). The study was prepared in partnership with the Union of Concerned Scientists, Earthjustice, BYD, Ceres, and NextGen Climate America, with advisory support from the University of California, Davis Policy Institute for Energy, Environment and the Economy, and East Yard Communities for Environmental Justice. ICF analyzed fourteen different types of medium- and heavy-duty vehicle classes, included a total cost of ownership calculation, an emissions impact assessment, and a macroeconomic analysis of various transportation investments required to reduce GHG emissions.

The total cost of ownership included cost components for the vehicle, operation and maintenance (e.g., fuel costs), and fueling infrastructure (e.g., charging infrastructure). When excluding incentives available in California (e.g., LCFS credits, utility incentives, and other state incentives), and depending on the vehicle class or vocation, electrification is still likely to be an appealing alternative to diesel trucks in the 2030 to 2050 timeline, assuming that battery prices continue to decrease.

ICF employed the same methodology in the previous study, including the same cost assumptions for vehicles, but updating electricity costs and non-electricity fuel costs for data specific to Michigan, and excluding any incentives or grants unique to California. ICF's updated analysis of the total cost of ownership across the same vehicle classes presented in the previous study indicates a GHG abatement cost range of about \$135/tCO_2e to \$400/tCO_2e for medium- and heavy-duty electric vehicle segments considered.

Deep Decarbonization in a High Renewables Future

E3's study for the California Energy Commission evaluated long-term energy scenarios to investigate options and costs for California to achieve a 40 percent reduction in GHGs emissions by 2030 and an 80 percent reduction in GHG emissions by 2050. The analysis incorporated mitigation strategies across all economic sectors.

As part of the analysis for the California Energy Commission, E3 included what they referred to as a truck portfolio, inclusive of battery electric trucks, hydrogen fuel cell vehicles, CNG vehicles, and hybridized powertrains. More specifically, E3 describes their mitigation scenario assuming

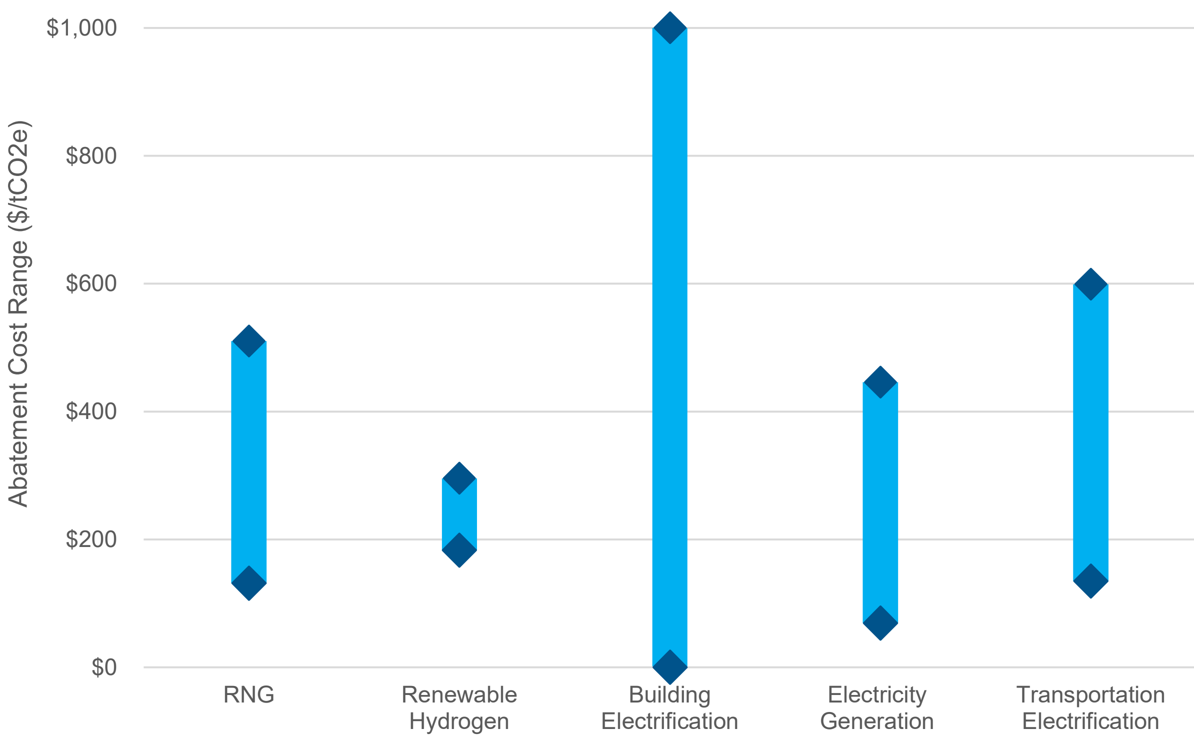
> that battery trucks can displace no more than 50% of truck vehicle miles (those used for shorter-haul distances), while fuel-cell trucks are assumed to serve longer-haul heavy duty trucking. As a result, hydrogen fuel cell heavy-duty trucks are a key "reach technology" in this scenario.

The E3 report does not specifically call out the GHG abatement costs for each of the truck technologies considered; rather the report presents a range across the truck portfolio. E3 reports a range of \$300/tCO_2e to \$500/tCO_2e for the truck portfolio in the High Renewables Future in 2016 dollars. When adjusted to 2022 dollars, this is represents a range of about \$359-599/ tCO_2e.

Abatement Cost Comparison

Figure 7-2 below shows a comparison of the selected measures as outlined in Table 7-1.

Figure 7-2. GHG Abatement Costs, Selected Measures (\$/tCO_2e)



Across all the selected measures, there are broad ranges of abatement costs. While these ranges are very broad, ICF finds that these large ranges actually reflect the unique circumstances and factors involved with the practical and detailed implementation of each emission reduction measure. Costs and emission reductions are greatly influenced by technology costs, efficiencies and availability, climate and geography, practical infrastructure constraints, whether local or system-wide, and the interconnected nature of emission reduction trends across the economy.

These abatement cost ranges make direct comparisons across emission reduction measures challenging, particularly if there is a lack of rigorous analysis designed for specific circumstances, such as in the context of Michigan. Furthermore, ICF asserts that a GHG abatement analysis conducted for each strategy included in Figure 7-2 with assumptions unique to Michigan would likely yield narrower ranges, as the analyses from other states and regions either do not include assumptions specific to Michigan or apply generalizing assumptions to reflect a broader geographic scope. However, the abatement cost estimates for RNG developed as part of this study can be used as a starting point to enable effective comparisons across emission reduction options.

In addition, it is clear based on the abatement costs shown in Figure 7-2 that RNG is potentially cost-competitive as an emission reduction approach, compared to other options relevant to the end-use of the RNG. For example, at a high level RNG is cost competitive with other low carbon gaseous fuels, such as renewable hydrogen (putting aside pipeline specifications and blending constraints).

In short, the abatement cost comparison outlined above shows that RNG can play a cost-effective role in achieving aggressive decarbonization objectives over the long-term, particularly as part of a comprehensive economy-wide strategy to reduce GHG emissions.

8. Opportunities and Barriers to RNG Production in Michigan

There are multiple opportunities for the deployment of RNG as an effective GHG emission reduction measure. The physical and environmental characteristics of RNG make for high development potential in Michigan, particularly in the context of ambitious long-term climate objectives. However, barriers and challenges remain, including limited capacity in current end-use markets, environmental impacts and social justice issues for some RNG feedstocks, and a limited policy structure. These barriers will need to be appropriately and adequately addressed through a robust, transparent and fair policy and regulatory environment that is not just limited to RNG, but for climate action more broadly.

The deployment of, and end-use demand for RNG is nascent but growing. With the ongoing expansion of the RNG market, there is increasing attention given to the opportunities and barriers associated with RNG production, delivery and end-use. In this section, ICF considers the highest-value opportunities and the corresponding challenges to realizing the potential of these opportunities in the RNG market. While the technical, market, regulatory, and environmental drivers for RNG are inextricably linked, we have distinguished between the key opportunities and challenges across these broad areas.

Technical

The technical potential for RNG over the next decade is constrained primarily by regulatory and market constraints, rather than technical ones. In large part, this is attributable to the fact that there are multiple feedstocks that can be converted to RNG using anaerobic digestion—this is a mature technology. Moving past 2025 and into a post-2030 reality, however, the technical potential for RNG will be constrained by the ability to expand beyond anaerobic digestion of feedstocks like landfill gas, animal manure, WRRFs, and food waste, and into technologies like thermal gasification. Thermal gasification is advancing rapidly, however, it should be considered in pre-commercial stages or very early commercial deployment. The transition to this type of production technology increases long-term RNG production potential substantially and can help drive down the long-term costs of RNG.

Opportunities

- **RNG fulfills current definitions of a renewable resource in Michigan with carbon neutral characteristics using a combustion accounting framework for GHG emissions.** The GHG benefits of RNG are clear: GHG emissions from RNG are lower than conventional natural gas across the board. The introduction of RNG has the potential to reduce GHG emissions significantly from the natural gas system. Furthermore, these GHG emission reductions are supported by policies that can improve waste management (e.g., landfill diversion), improve utilization of agricultural and forestry products, and generate additional revenue streams for some vulnerable parts of the economy.
- **RNG utilizes the same existing infrastructure as conventional natural gas.** When conditioned and upgraded to pipeline specifications, RNG can use the same extensive

system of pipelines for the transmission and distribution of natural gas. Improved and continuous monitoring of potential harmful constituents from RNG production can decrease the technical risks of contamination in the pipeline.

Barriers

- **Feedstock location and accessibility will constrain RNG production potential.** The location and availability of RNG feedstocks is mismatched with traditional demand centers for natural gas consumption. For example, many feedstocks are available in predominantly rural areas whereas demand is focused in urban centers. Some of these feedstocks may be difficult to access or may require substantial (and in some cases impractical) investments in infrastructure.
- **Competition for feedstocks will constrain RNG production potential.** There is a diverse array of feedstocks available for RNG production yet accessing some of those feedstocks can be difficult or prohibitive. Furthermore, as waste diversion policies improve over time, and decarbonization efforts presumably expand, biogenic and biomass feedstocks will have increasing value, thereby increasing competition for various energy production processes, including for gaseous fuels (i.e., RNG), liquid fuels (e.g., liquid biofuels like renewable diesel), and for renewable electricity. Technological advances in each of these markets will help determine the appropriate use of each feedstock, while the availability of that feedstock will still be constrained by other factors, including the rate of waste produced, agricultural outputs, and forestry outputs.
- **Gas quality and gas composition for RNG remains an engineering concern.** There is no existing industrywide standard for RNG gas quality and gas composition, and with limited operational data, some concerns remain regarding RNG injection into a pipeline system.

  For RNG to be suitable for introduction into the natural gas pipeline network, the initial raw biogas must be adequately processed to meet pipeline tariffs, state gas quality regulations, and end-use application standards. At a high level, this typically involves concentrating the methane content and removing any problematic constituents.

  While RNG is fundamentally interchangeable with conventional natural gas, different RNG feedstocks pose different challenges for gas quality and composition. For example, raw (unprocessed) biogas from a landfill facility is different than biogas from a dairy digester. Biogas constituents of classes vary by feedstock and conversion technology, and testing requirements need to be aligned to optimize results and processing requirements.

  Table 8-1 below shows Michigan's acceptable gas quality and gas purity requirements for service.

Table 8-1. Illustrative Quality Considerations for RNG Injection

Gas Quality Term	Generally Acceptable Limit
Hydrogen Sulfide	0.3 g/100 scf
Total Sulfur	20 g/100 scf
Carbon Dioxide (CO_2)	≤ 2.0%, by volume
Oxygen (O_2)	≤ 5 ppm_v
Heating Value	950 – 1,100 Btu
Water Vapor	< 7 lb/MMscf

Each element has a differing impact on gas quality and safety, interchangeability, end-use reliability and pipeline integrity. If a constituent is not reasonably expected to be found above background levels at the point of interconnect for the RNG, then testing may not be necessary. An additional challenge is that while some constituents may not present a problem in isolation, the interaction between different constituents could result in negative impacts on the pipeline or end-use applications.

ICF notes that Michigan has one of the lowest allowable oxygen limits; Michigan has promulgated these oxygen standards for pipelines to prevent corrosion in equipment at Michigan's gas pipeline facilities and storage reservoirs. At least one stakeholder[79] has noted that the oxygen limits may present a barrier to RNG development because it requires

> sophisticated oxygen removal equipment must be added to the RNG upgrade unit, adding ~ $600k to $1M for each RNG project. Furthermore, periodic replacement of the precious-metal catalysts adds even more cost - approximately 25% of the capital cost for each replacement.

ICF notes that this type of barrier is not uncommon for RNG development. However, as noted in the referenced comment, the technology exists to ensure that the required oxygen levels are achieved, and it is actually a matter of cost. This is not to say that ICF does not consider this issue a barrier to RNG deployment; rather, it is a barrier that can be overcome through additional investment in existing technology. Similar cost concerns were originally raised in California related to gas interconnect being costly in California compared to other jurisdictions. In this case, ICF notes that the cost adder is non-trivial; however, the context is relevant:

- In the context of project financing, the additional capital may be a barrier. However, in the context of the multiple millions of dollars that are required for investment in RNG projects, the barrier is likely small to modest.
- In the context of the LCOE estimates using ICF's cost model, which account for the cost of the gas over the life of a project, the additional upfront capital and the additional operations and maintenance costs contemplated for more

[79] Based on information submitted by Quantalux.

sophisticated oxygen removal equipment could increase the LCOE by $0.08 to $0.45 per MMBtu, depending on the project size and the feedstock.

ICF also notes that in the event that RNG from a project is being injected into distribution lines, that there is a process whereby a project owner can work with a gas utility to ensure blending to meet the oxygen requirements or the utility can seek a waiver from the oxygen requirement. This is not meant to diminish the technical barrier raised by stakeholders as it relates to the oxygen requirements for gas injection. Rather, ICF notes that these types of technical barriers can be overcome through investment and will likely be reduced over time through lessons learned during project development, and through technological innovation.

Substantial research, testing and analysis has been done to better understand the composition of raw biogas from different feedstocks compared to traditional pipeline-quality natural gas delivered into the natural gas system. In parallel, significant technology advancements have been achieved in processing and treating raw biogas to address trace constituents and the concerns of pipeline operators and end users.

For example, at the direction of the California Public Utilities Commission, the California Council on Science and Technology (CCST) assessed acceptable heating values and maximum siloxane specifications for RNG. CCST found that keeping the current minimum Wobbe Number requirement for RNG while relaxing the heating value specification to a level near 970 Btu/scf would not likely impact safety or equipment reliability. In relation to siloxanes, the CCST found that some RNG feedstocks are very unlikely to harbor siloxanes (e.g. dairy waste, agricultural residues or forestry residues), and less stringent monitoring requirements would be needed. The CCST also recommended a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes, due to inconclusive evidence for other RNG feedstocks.[80]

- **Seasonal variability in Michigan's natural gas systemwide demand may require the RNG production market to adapt.** Like other regions with colder winters, Michigan's natural gas system sees a significant winter peak, largely driven by space heating demand. There is a four- to five-fold difference in natural gas demand on the system between winter and summer months, and RNG production facilities do not have the same variability. For instance, during colder periods of the year when space heating requirements increase, RNG production facilities cannot be ramped up to meet increasing natural gas demand. Similarly, during warmer periods when demand is lower, RNG production may exceed demand in certain local distribution systems. Current RNG contractual structures are driven by natural gas demand as a transportation fuel and are not designed to accommodate the type of system variation required for space heating applications. As the RNG market evolves and matures, ICF anticipates that this issue can be solved through book-and-claim accounting[81], storage, and other considerations.

[80] CCST, 2018. Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications, https://ccst.us/reports/biomethane/.
[81] 'Book-and-claim' accounting is a common practice where an attribute or claim made by a party is separated from the physical flow of these goods.

However, as the RNG market transitions from transportation fuel use to more diverse end uses on the natural gas system, there will be growing pains.

Market

There are more than 120 projects producing RNG for pipeline injection today, compared to less than a half-dozen in 2010. In Section 3, ICF provided an outline of RNG potential for pipeline injection, broken down by feedstocks and production technologies. Based on this untapped potential, the RNG market is poised for substantial growth. The following section outlines the most significant opportunities driving the RNG market, and the most significant barriers that must be overcome.

Opportunities

- **RNG can deliver cost-effective GHG emission reductions for decarbonization.** RNG is a cost-effective GHG emission reduction measure, and relative to other GHG mitigation measures, RNG can play an important role in helping to achieve decarbonization out to 2050.
- **RNG helps maximize the utilization of evolving waste streams.** The anaerobic digestion of biomass, including at landfills and WRRFs, helps maximize the use of waste. With expanding urban populations and more pressure for landfill diversion, the anaerobic digestion of food waste and thermal gasification of MSW, for instance, has the potential to continue to increase the utilization of waste streams as renewable energy resources.
- **RNG markets are evolving to reflect utilities and corporations with climate and sustainability goals.** There is increasing activity and interest in RNG outside of the transportation sector, and also beyond jurisdictions where carbon constraining policies are influential. Driven by corporate sustainability goals and customer preferences, a growing number of utilities and large end users of natural gas are looking into RNG as an option to reduce GHG emissions.
- **RNG helps give suppliers and consumers a viable decarbonization option in an evolving market and policy environment.** There is an escalating trend for utilities and large industrial consumers to adopt ambitious decarbonization measures, while small consumers are increasingly aware of their carbon footprint and looking for ways to reduce emissions.

Barriers

- **Changes in California's LCFS or the federal RFS, may negatively impact the economic feasibility of Michigan-based RNG projects.** Although the LCFS and RFS programs have helped to drive considerable investment in RNG, including in Michigan, changes to either of these programs may impact existing RNG projects or limit the near-term growth potential for RNG projects in Michigan. Like most of the RNG market today, investments in Michigan-based projects are being driven by these policies and the value of the environmental commodities. These RNG projects carry the merchant risk of volatile environmental commodity markets, as well as the uncertainty related to programmatic changes that can be made by program administrators.

- **Markets for RNG beyond transportation fuel are nascent.** The long-term growth potential for RNG is dependent on transitioning to end uses other than transportation. Michigan's market will need to demonstrate a near-term market potential for RNG deployment to bolster stakeholder confidence in the ability of RNG to deliver cost-effective GHG emission reductions. However, absent other markets for RNG consumption, production investments will stall and the market will plateau.
- **RNG production and processing costs need to be reduced to improve cost-competitiveness.** The market for RNG will expand beyond the transportation sector through improved technology and complementary policies. However, technology and overall production costs need to decrease over time to maintain competitiveness.
- **Limited availability of qualified and experienced RNG developers to expand RNG production in the near-term.** With growing interest in RNG projects, particularly to capture near-term value in the transportation market, there is a lack of experienced project developers (perceived or real) to meet this demand. This issue will ameliorate over time, as the industry expands and project developers gain more experience on RNG projects.
- **RNG costs more than conventional natural gas, when environmental benefits are not fully valued.** The capital expenditures and operational costs associated with RNG production are higher than the commodity price for conventional natural gas, greatly restricting the potential for RNG production and consumption. However, the costs of RNG should not be compared directly with conventional natural gas without reflecting the significant GHG emission reduction benefits of RNG.
- **Interconnection costs for RNG suppliers and developers can be high.** Interconnection serves a vital role in an RNG project—it is the point at which gas quality is monitored, prevents non-compliant gas from entering the system, and meters the RNG injected. On a project-lifetime basis, interconnection costs are generally small as the cost is amortized, for instance, over a 10- to 20-year project lifetime. However, meeting interconnection costs can be a challenge for project developers.

  There is no "right cost" associated with interconnection. Instead, gas utilities need to work with regulators and project developers to ensure safety and reliability are maintained on the system, and that utilities can recover the costs associated with the system requirement. Utilities, along with regulators, have strategic roles to work with potential RNG suppliers and project developers to:

  - Research and evaluate suitable site locations;
  - Determine pipeline interconnection distances and pathways;
  - Develop engineering designs and configurations;
  - Determine appropriate flows and pressures; and
  - Conduct initial project cost estimates.

Regulatory and Policy

The aforementioned incentives for the use of RNG as a transportation fuel helped spur substantial investment in new RNG projects nationwide. However, the demand for RNG as a transportation fuel is limited and tied to the growth of NGVs. For RNG to play a role in long-term GHG mitigation strategies, a regulatory and policy structure is required to support the cost-effective use of pipeline-injected RNG.

There is growing activity outside the transportation sector, and in particular the construct of the RFS and LCFS programs, where so much attention is paid today. With deep decarbonization goals becoming more prevalent, the ability to use an existing energy system to deliver significant emission reductions is highly valuable. RNG as a decarbonization approach for stationary energy applications provides two advantages relative to other measures:

- Utilizes existing natural gas transmission and distribution infrastructure, which is highly reliable and efficient, and already paid for, and
- Allows for the use of the same consumer equipment as conventional gas (e.g., furnaces, stoves), avoiding retrofits and upgrades required for fuel-switching

For example, DTE launched a voluntary biogas program in 2013, amended and expanded in 2020 to become the Natural Gas Balance Program, which supports the development of RNG projects in Michigan. Regulators, policymakers and gas industry participants are implementing or developing RNG programs across the country:

- Minnesota HF7: allows gas utilities to file innovative resource plans, and requires the PUC to establish GHG and cost-benefit accounting frameworks to assess plans. Plans can include RNG as part of innovative resources.
- Ohio HB 166: allows gas utilities to treat RNG-related infrastructure as useful and eligible for cost recovery.
- The joint venture between Dominion Energy and Smithfield Foods is set to become the largest RNG producer in the U.S., developing animal manure-based RNG in North Carolina, Virginia, and Utah, with plans to expand to California and Arizona.
- TECO Peoples Gas in Florida had a tariff for biogas conditioning and upgrading approved in December 2017, and have since made modifications to the tariff to accommodate the receipt of RNG from biogas producers and an updated rate schedule for conditioning services.[82]
- In early 2022 the California Public Utilities Commission adopted a mandatory RNG program, where the state's largest gas utilities need to procure increasing volumes of RNG out to 2030.
- Oregon SB 98: allows natural gas utilities to make "qualified investments" and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail customers. The RNG portfolio targets range from 5% between 2020 and 2024 to 30% between 2045 and 2050.
- Nevada SB 154: authorizes natural gas utilities to engage in RNG activities and to recover the reasonable and prudent costs of such activities, including the purchase of

[82] TECO Peoples, Section 7 of the tariff is available online at https://www.peoplesgas.com/company/ournaturalgassystem/tariff/.

and production of RNG. The legislation also includes voluntary procurement targets of not less than 1% of the total amount of gas sold by 2025, not less than 2% by 2030, and not less than 3% by 2035.

- Approved in 2017, Vermont Gas offers a voluntary RNG tariff program, providing retail gas customers the opportunity to purchase RNG in amounts proportionate to their monthly requirements. [83]
- FortisBC, the main gas utility in the Canadian Province of British Columbia, has had a voluntary RNG tariff program since 2011, which has spurred RNG production in the region.[84]
- National Grid's New York City Newtown Creek RNG demonstration project will be one of the first facilities in the U.S. that directly injects RNG into a local distribution system using biogas generated from a water and food waste facility.
- Southwest Gas Company (SWGC) in Arizona has a biogas services tariff enabling them to enter into a service agreement with a biogas or RNG producer, and includes requirements for access to the production facilities, interconnection facilities, and gas quality testing facilities.[85]
- Southern California Gas Company (SoCalGas) announced that they intend to have 5% RNG on their system by 2022 and 20% by 2030. SoCalGas is also seeking approval to allow customers to purchase RNG as part of a voluntary RNG tariff program. [86]

Driven by corporate sustainability goals and customer preferences, a growing number of large end users of natural gas are looking into RNG as an option to reduce GHG emissions. Global cosmetics manufacturer L'Oréal uses RNG from a nearby landfill facility at its plant in Kentucky. L'Oréal's long-term purchase commitment for the RNG was a key underwriting component that led to the financing of the LFG project.

While there is clearly a near-term focus on reaping the benefits of credits generated in the LCFS program and RINs in the RFS program, the long-term potential for increased volumes of RNG outside the transportation sector is considerably more robust than many stakeholders may realize. With appropriate incentives that fully reflect the environmental impacts of RNG, the end-use demand for RNG from stationary applications is substantial, in contrast to the limited demand in the transportation sector.

ICF notes that the majority of the measures and actions outlined above are voluntary in nature, and do not deliver binding RNG deployment targets or GHG emission reduction objectives. Voluntary programs and opt-in green tariffs provide near-term opportunities for natural gas utilities, regulators and customers to become accustomed to RNG and the RNG market, without requiring substantial and long-term commitments. Voluntary markets have been critical to the initial growth of emission reduction measures, such as renewable electricity through residential

[83] Vermont Gas, 2022. https://www.vermontgas.com/renewablenaturalgas/.
[84] FortisBC, 2022. https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas
[85] SWGC, Schedule No. G-65, Biogas and Renewable Natural Gas Services , available online at https://www.swgas.com/1409197529940/G-65-RNG-02262018.pdf.
[86] SoCalGas, information retrieved from https://www.socalgas.com/for-your-business/power-generation/biogas-conditioning-upgrading.

and non-residential customers voluntarily helping grow demand considerably in the early years of renewable electricity development.

However, over the long-term, and considering the significant economy-wide emission reductions needed to meet deep decarbonization goals, the policy and regulatory framework for RNG will need to be more ambitious and comprehensive. For example, a mandatory Renewable Gas Standard for gas utilities would be relatively straightforward and mimic parallel renewable portfolio standards on the electric supply side.

Opportunities

- **Conditioning and Interconnection Tariffs.** As outlined in Section 3, the costs of biogas conditioning and upgrading can be expensive; similarly, interconnection costs can be challenging for some project developers. These costs are the primary capital outlays at the outset of a project and have a material impact on the ability of projects to obtain financing. Under a tariff structure, the producer can avoid the significant upfront capital costs that can often impede project development. Conditioning and interconnection tariffs allow utilities or LDCs to build and operate the upgrading and interconnection facilities, while recovering capital and operation and maintenance costs from the project developer at a pre-determined rate.
- **Emergence of legislation and regulations for both mandatory and voluntary programs.** Utilities may offer opt-in voluntary programs to customers to help reduce the environmental impact of their energy supply. This is more common for electric utilities, however, similar programs can be developed for gas utilities and RNG consumption.
- **Complementary policies could facilitate RNG feedstock collection (e.g., waste diversion and management).** The RNG industry could benefit considerably from complementary policies that help improve the accessibility of feedstocks while improving project development economics. This includes regulations or policies that encourage methane capture, encourage waste diversion and waste utilization, forest management and thinning requirements, etc.

Barriers

- **The pathway for policies and incentives promoting RNG in market segments other than transportation is unclear and not uniform.** Current programs in place do not provide the price and supply certainty that is required for larger volumes of RNG to be deployed, beyond the success of RNG in the transportation fuels market. While voluntary commitments and other drivers may help to increase RNG consumption in non-transportation market segments, the potential for RNG is intrinsically constrained without a strong policy signal in place. Furthermore, the programs that have been proposed or even promulgated are generally lacking or insufficient, and do not recognize or credit the environmental benefits of RNG in a manner that is consistent with the long-term potential of the technology.
- **Gas utilities are just beginning to gain cost-recovery mechanisms for RNG procurement and investments.** There has been rapid expansion of RNG production over the last several years; however, the industry will face limits as technical and market constraints limit market participants. Faced with varying pressures to decarbonize,

utilities need cost-recovery mechanisms for RNG procurement or investments, if they are to play a role in the development of these projects. In particular, natural gas utilities will need a regulatory structure that provides cost recovery for the incremental costs of RNG, interconnection facilities and equipment for RNG to comply with gas quality specifications and standards, and investment in larger facilities such as pipelines and premium gas production, supply facilities, and pipeline capacity costs that would support and facilitate the development of RNG.

Environmental Impacts

Section 6 outlines the environmental value of RNG, in the context that it can deliver GHG emission reductions as a low carbon gaseous fuel. However, to assess accurately the complete potential of RNG as a fuel in a decarbonizing economy, a broader perspective on the impacts of RNG is needed.

Opportunities

- **Investments in RNG production can yield positive environmental impacts upstream from the gas system and beyond GHG emissions.** These include reducing or avoiding methane emissions from certain biomass feedstocks, helping to achieve waste management targets (e.g., waste diversion and waste utilization), supporting sustainable management practices in the agricultural and forestry sectors, and reducing the environmental impacts of CAFOs.
- **If new policies are implemented to support RNG deployment in Michigan, they should ensure no back-sliding on other environmental indicators and avoid environmental injustices that have historically impacted at-risk communities.**

Barriers

- **RNG development will face scrutiny as it relates to fugitive methane emissions, which occur along the entire natural gas supply chain—during processing, transmission, and distribution.** This is a pressing issue for the natural gas industry and is not unique to RNG production. In the context of RNG production, most of the fugitive methane emissions would occur during transmission of the product via pipeline, however, these emissions would not be considered incremental or additional GHG emissions; rather, those same GHG emissions would have occurred if the alternative was conventional natural gas. Methane emissions are particularly harmful because of the gas's high global warming potential. Fugitive methane emissions in the natural gas supply chain have become a pressing issue for the natural gas industry over the past decade. The issue has been brought into focus in large part by a collaboration of the Environmental Defense Fund (EDF), universities, research institutions, and companies that completed 16 projects to collect data on methane emissions from the natural gas supply chain from 2013 to 2018.[87] These studies helped to demonstrate that the

[87] EDF. 2018. Methane research series: 16 studies, accessible online at https://www.edf.org/climate/methane-research-series-16-studies.

methane emissions from natural gas supply chains were considerably higher (up to 60%) than the estimates from the EPA's GHG emissions inventory.[88]

- **There are a variety of environmental impacts of CAFOs, which represent one of the key feedstocks for RNG production in Michigan**, accounting for 18% and 14% of the RNG production potential in the Achievable and Feasible scenarios, respectively. Some of the environmental impacts attributable to CAFOs include:[89]
  - Manure contains variety of potential contaminants. Plant nutrients such as nitrogen and phosphorous, pathogens such as *E. coli*, growth hormones, antibiotics, chemicals used as additives to the manure or to clean equipment, animal blood, silage leachate from corn feed, or copper sulfate used in footbaths for cows
  - CAFOs are a source of strong odors and are known to increase insect vectors.
  - The manure often presents risks to ground and surface water quality.
  - CAFOs tend to emit air pollutants such as ammonia, hydrogen sulfide, methane, and particulate matter.
  - Left untreated or managed via digesters, CAFOs are a source of GHG emissions via the methane that is emitted

  These environmental harms lead to environmental justice concerns and impacts. The negative impact on air quality and water quality in communities surrounding CAFOs can lead to disproportionate harms like increased asthma rates. There is also evidence that CAFOs depress property prices in surrounding communities.

  At present, there is no clear indication that RNG policies or RNG production will impact industry trends related to CAFOs or contribute to the expansion of CAFOs in Michigan. To the contrary, the use of anaerobic digesters at farms is more likely to mitigate environmental harms at existing CAFOs than exacerbate them. Regardless, it is important that there are controls put in place to ensure that RNG development does not lead to increased environmental harms or increase the risk of exposure to environmental injustices in at-risk communities.

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[88] Alvarez, R., et al., 2018, Assessment of methane emissions from the U.S. oil and gas supply chain, Science, DOI: 10.1126/science.aar7204.
[89] Understanding Concentrated Animal Feeding Operations and Their Impact on Communities, available online at https://www.cdc.gov/nceh/ehs/docs/understanding_cafos_nalboh.pdf.

Appendix A

Understanding the Current RNG Value Stack

Low carbon fuels, such as ethanol, biodiesel, renewable diesel, and RNG, that are deployed in California have the potential to earn LCFS credits in the state-level LCFS program as well as Renewable Identification Numbers (RINs) in the federal RFS program. Fuel providers can generate value in both the LCFS and the RFS programs by rule. The programs are implemented by tracking two different environmental attributes: the state-level LCFS program enables fuel providers to monetize the GHG reductions attributable to the fuel, whereas the federal-level RFS program monetizes the volumetric unit of the renewable fuel. This ability to "stack" environmental credits has led to the aforementioned significant increase in the volume of RNG consumption in California. For instance, ICF estimates that 60-65% of domestic RNG production in 2021 was delivered to California, generating both the RINs and the LCFS credits. The following subsections provide an outlook on these two markets and the role of RNG over the next 5-10 years.

The table below highlights the current value stack for RNG in 2022, assuming that the fuel is used in a NGV in California.

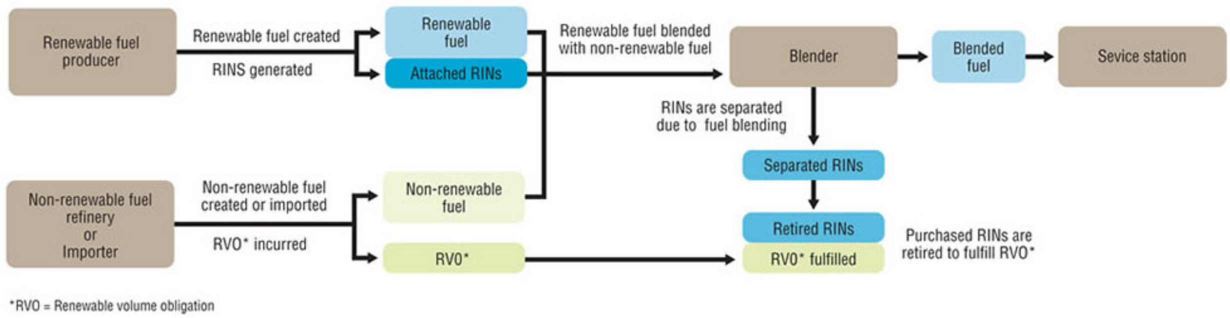
Table A-1. RNG Value Stack as a Transportation Fuel in California

RNG Value Stack ($/MMBtu)	RNG from Landfill CI: 45 g/MJ	RNG from dairy manure CI: -250 g/MJ
Commodity Value	$7.40	$7.40
D3 RIN *$3.41 per D3 RIN*	$40.00	$40.00
LCFS Credit *$115/ton*	$3.98	$36.30
Total	$51.37	$83.69

EPA Renewable Fuel Standard

The RFS mandates biofuel volumes that must be blended into transportation fuel each year from 2006 to 2022. The program was developed as part of the Energy Policy Act (EPAct) of 2005 and revised/updated by the Energy Independence and Security Act (EISA) in 2007. The program is administered by the EPA. The RFS policy mandates that producers of petroleum fuel products and blenders add in renewable fuels into their pool every year. Every gallon of renewable fuel is given a Renewable Identification Number or RIN. Among other things, the RIN identifies who made the fuel, when, and what type of fuel it is. The RINs can be sold along with the fuel or "separated" and sold to an obligated party (e.g., a petroleum refinery) separately. Typically, the RIN is sold with the volume of fuel to a blender who then sells the blended fuel to fuel outlets (e.g., retail gasoline stations). The blender then sells the "separated RIN" back to the refinery. A diagram is shown below.

Figure A-1. Overview of the Federal RFS Program



Each year, the EPA estimates the volume of transportation fuel that is expected/forecasted to be consumed in the U.S., using projections from the EIA. The Renewable Volume Obligations (RVOs) are expressed as a percentage of this expected nationwide fuel consumption. EPA is required to set the standards by November 30 for the following year. Changes to the program in the EISA created four nested categories, as shown in the table below: renewable biofuels, advanced biofuels, biomass-based diesel, and cellulosic biofuels. Each category has its own volume requirement and RIN type. RINs are the currency of the RFS program and are represented by a 38-digit code representing an ethanol gallon equivalent of fuel. Each category includes a threshold of lifecycle GHG emission savings compared to petroleum products (i.e., gasoline and diesel).

Table A-2. Nested Categories of Renewable Fuels in the RFS Program

RIN Type	Description / Biofuel	Min GHG Reductions	RFS Qualifying Categories
D3	Cellulosic Biofuel	60% GHG savings	Cellulosic, Advanced or Renewable
D4	Biomass-Based Diesel	50% GHG savings	Biomass-Based Diesel, Advanced or Renewable Diesel
D5	Advanced Biofuel	50% GHG savings	Advanced or Renewable
D6	Renewable Fuel	20% GHG savings	Renewable (Corn-Based Ethanol)
D7	Cellulosic Diesel	60% GHG savings	Cellulosic or Advanced, Biomass-Based Diesel, or Renewable

Through the annual RVO setting process, the EPA has established cellulosic biofuel volumes that are lower than the statutory volumes for the years 2010 to 2020, and the proposed values for 2021 and 2022. The annual RVO setting process has recommended lower volumes than statutory volumes because available supply has been insufficient to maintain the annual RVOs at the same level as statutory volumes. Despite annual volumes being lower than statutory volumes, the supply of cellulosic biofuels has increased year-over-year, with more significant increases in the last 3-5 years. Consider the year 2020: the statutory volume for cellulosic biofuels was 10.50 billion gallons; however, the final annual RVO established by the EPA was 0.59 billion gallons. Because the annual RVO was lower than the statutory volume, the Cellulosic Waiver Credit (CWC) provision was enacted. CWCs are not allowed to be traded or banked for future use and are only allowed to be used to meet the cellulosic biofuel standard in the year for which they were offered. An obligated party can satisfy its D3 RIN obligation by either (i) purchasing a D3 RIN or (ii) paying the CWC and purchasing a D5 RIN.

- The CWC is calculated based on the formula in the regulation, which is the greater of \$0.25 or \$3.00 minus the average wholesale price of gasoline ($P_{gasoline}$). Both of the constants in the formula, \$0.25 and \$3.00, are adjusted for inflation from January 2009 (per the regulation) to June of the year in question. Fundamentally, the CWC price increases as gasoline prices decrease, and declines as gasoline prices increase.
- ICF models D5 RIN values based on lowest cost economics of advanced biofuel production and forward markets for commodities. We also note that we put maximum and minimum value on the D5 based on the nested structure of the RFS. In other words, the D5 RIN must always be less than the D4 RIN (biodiesel) and greater than the D6 RIN (corn ethanol). Forecasting RINs requires that modeling considers annual RVOs and the supply-demand of eligible advanced biofuels, and in most years, this yields a compliance pathway in which D4 RINs are the marginal unit of compliance. As such, biodiesel production economics tend to drive D5 RIN pricing.

ICF forecasts D3 RIN values as the sum of a D5 RIN and the CWC, and the product of a market-based discount factor.

For the purposes of this study, ICF assumed that the RFS regulation remains in place post-2022. Changes to the RFS post-2022 would require legislation passed by the U.S. Congress. Any price changes post 2022 reflect technological improvements and cost-competitiveness in each sector. ICF also assumed that the EPA would adjust/reduce the volume of cellulosic biofuel on an annual basis to match production volumes of eligible D3 RIN generating projects. ICF reports a range of values for the D3 RIN out to 2030.

Table A-3. Forecasted D3 RIN Pricing to 2030 (\$2022)

	2021[A]	2022	2023	2024	2025	2026	2027	2028	2029	2030
D3 RIN	2.67	2.95-3.15	2.10-2.30	2.45-2.55	3.35-3.60	2.95-3.30	2.90-3.25	3.00-3.35	2.86-3.21	3.07-3.42

Notes:
1. 2021 Values are presented as actual values.
2. The D3 RIN value reported for 2021 is the weighted average of Q-RIN transactions.
3. Values are reported as \$/D3 RIN in Real terms using 2022 (\$2022).

ICF notes that RINs are all reported in units of ethanol gallon equivalents, and one gallon of ethanol is assumed to have 77,000 Btu. In order to determine the number of RINs generated by 1 MMBtu of natural gas, the equation is:

1,000,000 Btu [RNG] / 77,000 Btu [Ethanol Equivalence] x 0.903 [adjust for LHV / HHV of natural gas] = 11.727 RINs per MMBtu of RNG

In other words, a D3 RIN value of \$3.00 is equivalent to \$35.18/MMBtu.

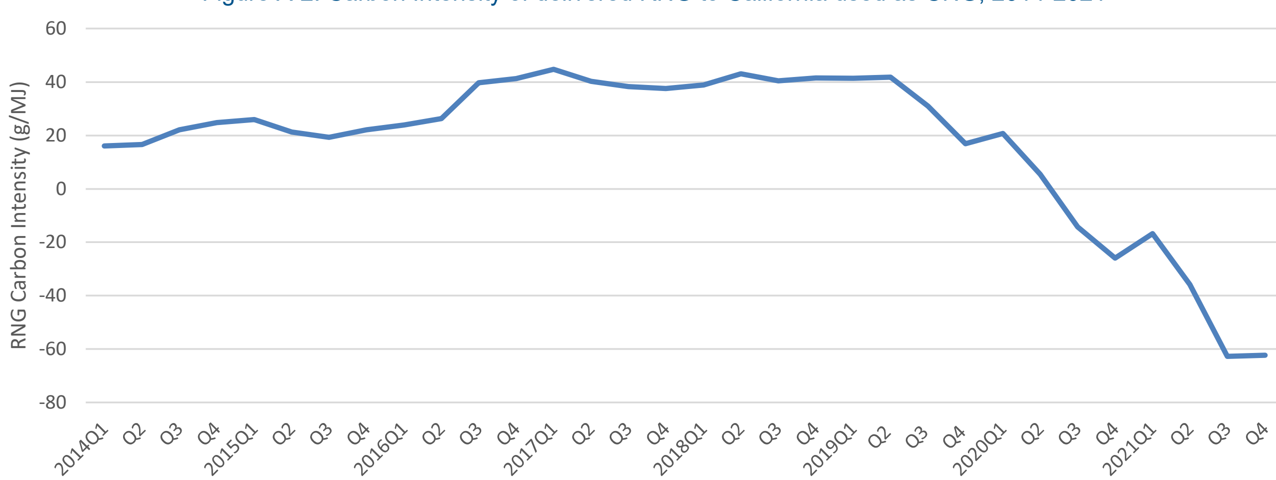
California's Low Carbon Fuel Standard

California has in law, in regulation, and in executive orders the most aggressive GHG reduction program in the world, requiring staged emissions reductions of 80% over the coming years. California's steep GHG reduction goals require emissions reductions in every sector of the economy. Transportation produces the largest portion of California's GHG emissions, 37% of total emissions. The AB 32 Scoping Plan identified California's LCFS Program as an Early Action Item. The standard required a 7.5% reduction in transportation fuel carbon intensity by 2020 and requires a 20% reduction by 2030. The program began in 2011. Carbon intensity (CI) is measured in grams of carbon dioxide equivalents (gCO_2e) per unit energy (megajoules, MJ) of fuel and is quantified on a lifecycle or well-to-wheels basis. The LCFS is the most significant emissions reduction program in the California transportation sector, delivering as much reduction as all other transportation programs combined. The reductions delivered by the LCFS are essential to achieving overall GHG goals. In 2007, Governor Schwarzenegger signed an executive order establishing the Low Carbon Fuel Standard. California Air Resources Board enacted the LCFS regulation in 2009, updated the program in 2011, and re-adopted the program in 2015. The LCFS measures the full "lifecycle" (well-to-wheels or field-to-wheels) carbon emissions of fuels.

The LCFS program operates on a simple system of deficits and credits. Petroleum-based transportation fuels (i.e., gasoline and diesel) with a CI higher than the standard generate deficits; these deficits must be offset on an annual basis by credits generated by lower carbon fuels. Unlike RINs in the RFS program, LCFS credits can be banked without holding limits and do not carry vintages.

There are about 45 registered LFG pathways in California's LCFS program, with a maximum carbon intensity of 67 g/MJ and a low of 30.5 g/MJ, and a median of 41.5 g/MJ. For illustrative purposes, ICF has included the average carbon intensity of RNG since 2014.

Figure A-2. Carbon Intensity of delivered RNG to California used as CNG, 2014-2021[90]



[90] Based on data released by the California Air Resources Board.

Most of the RNG that is currently delivered to and dispensed in California and Oregon is derived from landfills. However, ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and from digesters deployed at WRRFs. For instance, the figure above shows a precipitous decrease in the *average* carbon intensity of RNG delivered through 2021, indicating the emergence of several low CI pathways from animal manure projects that have been increasing deliveries to California. Over time, these lower carbon sources will continue to displace substantial volumes of higher carbon intensity RNG from landfills in the California (and Oregon) market, however, these alternative sources of RNG tend to have smaller production profiles and will not be able to displace landfill gas entirely in the system.

ICF models the LCFS program using an optimization model that considers compliance strategies based on parameters including alternative fuel production costs, fuel supply chains (to California), interactions between programs, alternative fuel pricing, gasoline and diesel pricing, and GHG abatement potential. ICF developed the model to solve dynamically for the lowest-cost (and in the case of LCFS forecasting, the lowest emission) solution while considering inter-temporal trading and banking behavior on an annual basis.

ICF modifies critical parameters across multiple model runs to identify the range of compliance scenarios and identify the most likely marginal units of compliance in relevant markets (e.g., the LCFS program and the RFS program). Based on this, the model estimates the corresponding environmental commodity price (including RIN prices and LCFS credit prices) as the difference between the delivered cost of the marginal unit of compliance and the forecasted price of gasoline or diesel. As the environmental commodity prices rise, additional compliance opportunities (including additional supply of existing compliance pathways or new compliance pathways) are considered viable. However, the model is not exclusively constrained by price, it is also constrained by fuel supply and consumer behavior, and it also accounts for lag times between pricing signals and investment required to deploy alternative fuels.

In 2018, LCFS credits traded at an average of $160/ton with a range of $79/ton to $202/ton; in 2019, credits traded for an average of $192/ton with a range of $85/ton to $209/ton, credit prices increased as the stringency of the program increased, and obligated parties were facing a market with constrained low carbon fuel supply compared to the demand for credits while 2020 averaged $200/ton over the year. In 2021, however, LCFS credit prices decreased substantially but held an annual average of around $179/ton. Price decreases have continued into 2022, with an average credit price trading around $138/ton through April 2022.

For the purposes of this study, ICF assumed that the LCFS regulation is implemented as currently designed, with a 20% CI reduction by 2030. ICF reports a range of values for LCFS credits out to 2030.

Table A-4. Forecasted LCFS Credit Pricing to 2030 ($2022)

	2021[A]	2022	2023	2024	2025	2026	2027	2028	2029	2030
LCFS Credit Price	179	82-114	88-108	123-143	130-160	137-167	143-173	148-174	148-174	143-173

Notes:
1. 2021 Values are presented as actual values.
2. Values are reported as $/credit in Real terms using 2022 ($2022).

The value of LCFS credits is determined by the CI of the project. For instance, a credit price of $150/ton is worth about $7/MMBtu of RNG from landfills (with a CI of 40 g/MJ), and about $55/MMBtu for RNG sourced from dairy manure digesters (with a CI score of -250 g/MJ).

Rise of Non-Transportation Demand

The combination of RINs and LCFS credits have helped deliver significant volumes of RNG, especially to California. In fact, as of the end of 2021, RNG accounted for more than 90% of the market for natural gas as a transportation fuel in California. As lower carbon RNG comes on to the market, end users will likely gain additional market influence. Most of the RNG that is currently delivered to and dispensed in California is derived from landfills. ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and digesters deployed at wastewater treatment plants.

Over time, these lower carbon sources will likely displace higher carbon intensity RNG from landfills. The role of RNG in the LCFS program will be determined by the market for NGVs. If steps are taken to foster adoption of NGVs, particularly in the heavy-duty sector(s), then this will be less of an issue. The introduction of the low-NOx engine (currently available as an 9L, 12L, and 6.7L engine) from Cummins may help jumpstart the market, especially with a near-term focus on NOx reductions in the South Coast Air Basin (which is in severe non-attainment for ozone standards).

However, California has a clear focus on zero emission tailpipe solutions for the transportation sector e.g., via the Advanced Clean Truck (ACT) regulation. The ACT Regulation requires zero-emission purchase requirements for medium- and heavy-duty trucks starting in 2024. The rule seeks to “accelerate the widespread adoption of [ZEVs] in the medium- and heavy-duty truck sector.” The core compliance mechanism is a minimum performance standard for ZEVs as a percentage of each major truck manufacturer’s new sales in California.

While the deployment of RNG in the transportation sector has experienced massive growth in the past five years, there is a clear constraint to the overall production and use of RNG in transportation: the limited number of NGVs. With the transportation sector approaching RNG saturation, there is growing interest from policymakers, regulators and industry stakeholders to grow the production of RNG for pipeline injection and stationary end-use consumption.

As currently constructed, in general the policy framework does not encourage RNG use in stationary applications, instead directing RNG consumption to the transportation and electricity generation sectors. However, there are several emerging state-level policies in place that are helping to shape the outlook for RNG beyond transportation. The most interesting development for RNG is that there is growing interest in applying the same principles of RPS program as it relates to electricity to the natural gas sector. These are often referred to as Renewable Gas Standards. Oregon’s Senate Bill 98 (SB 98), for instance, established a voluntary goal for adding as much as 30% RNG into Oregon’s system by 2050. Furthermore, the law allows up to 5% of a utility's revenue requirement to be used to cover the additional cost of investments in RNG infrastructure. More specifically, the bill operates similar to a renewable portfolio standard, whereby volumetric goals have been set, and other critical parameters have been established to support cost-effective procurement. Utilities are able to invest in and own the processing and conditioning equipment required to upgrade raw biogas to pipeline quality gas, as well as the interconnection facilities to connect to the local gas distribution system. To date, NW Natural in Oregon has executed two agreements that will deliver about 2% of NW Natural's annual sales in Oregon, including agreements with a) Tyson Foods and BioCarbN to convert waste to RNG at Tyson facilities and b) Element Markets to purchase the environmental attributes from a WRRF in New York City and a mixed waste anaerobic digester in Wisconsin.[91]

[91] These attributes are referred as Renewable Thermal Certificates or RTCs, and are verified and certified by the Midwest Renewable Energy Tracking System (M-RETS). In this case, each RTC is equivalent to a dekatherm or about 1 MMBtu.

Appendix B

Common Applications of GHG Emission Accounting for RNG

Through the 1990s and into the early 2000s, most biogas projects were located at landfills or dairy farms and were capturing biogas to convert it to electricity. Most of these projects were developed to support individual state Renewable Portfolio Standards (RPS). However, the advent of the federal Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS) shifted incentives away from biogas use in the electricity sector, and toward the upgrading of biogas into RNG use in the transportation sector as a vehicle fuel. Within a short time, projects that were using RNG feedstocks to generate electricity, transitioned to producing RNG because of the financial incentives available through the RFS and LCFS programs. Today, RNG is primarily used in the transportation sector to reduce GHG emissions, however recent regulatory programs have started to emerge that would incentivize the use of RNG in thermal applications.

The principles of GHG emission accounting methods are employed to various extents when it comes to developing and implementing policy. The intent of a policy matters, and is often influenced by political, social, or economic pressures outside the scope of GHG emission accounting methods. While a lifecycle GHG emission accounting approach or a combustion GHG emission accounting approach may provide a foundation for how a policy or regulation is implemented, it is not the only factor considered in policies that are developed to reduce GHG emissions.

Federal Renewable Fuel Standard

The federal RFS mandates biofuel volumes that must be blended into transportation fuel each year from 2006 to 2022. The program was developed as part of the Energy Policy Act (EPAct) of 2005 and revised/updated by the Energy Independence and Security Act (EISA) in 2007. The program is administered by the EPA. RNG was designated as an eligible fuel in 2014 as part of RFS rule amendments. The EPA determines the eligibility of a fuel pathway using a series of requirements outlined in statute and regulations. One of the primary requirements is that a fuel must achieve a percent reduction in GHG emissions as compared to a petroleum baseline (with a baseline year of 2005), and this is determined on a *lifecycle GHG emissions accounting basis*.

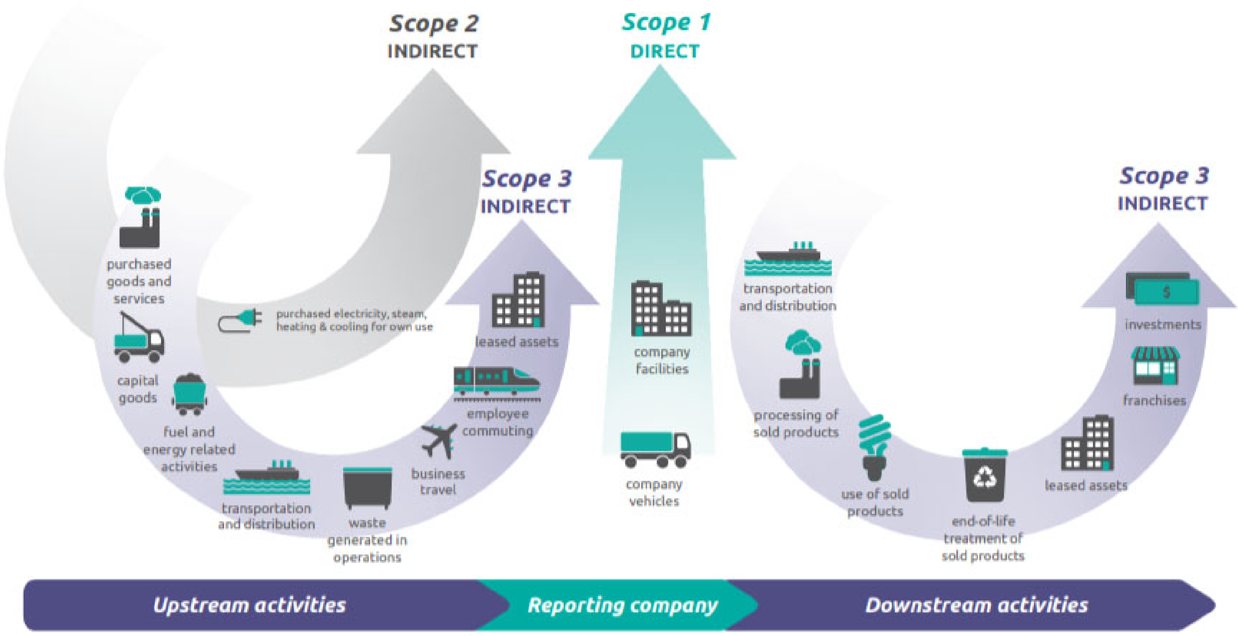
Low carbon fuel standards

A low carbon fuel standard is a performance-based program that seeks to reduce the carbon content of transportation fuels. California's LCFS program was identified as an Early Action Item as part of a broader scoping plan delivered by California regulators—the scoping plan identifies how California expects to achieve its GHG emission reduction targets in line with existing regulations. Oregon has a similar program called the Clean Fuels Program (OR CFP) and it is administered by the Oregon Department of Environmental Quality. Oregon's program operates like California's for the most part, but the carbon intensity reduction requirement differs since the program was introduced in 2016. Both the California LCFS and the Oregon CFP employ a lifecycle GHG emissions accounting method to determine the carbon intensity of eligible transportation fuels, which helps to determine the value of a particular fuel. In other words, the fuels with the lowest carbon intensity generate more credits per unit of energy and ultimately generate more value to the producer.

Renewable Portfolio Standards
Renewable portfolio standards seek to increase the amount of electricity generated from qualified renewable resources, including, but not limited to wind, solar, biomass, and hydro. State-level RPS programs focus on renewable electricity generation, with eligible generation technologies varying across jurisdictions including, but not limited to solar photovoltaics, wind turbines, certain geothermal electric technologies, small hydroelectric facilities, fuel cell technologies, and others. RPS programs are typically administered by placing an obligation on electricity supply companies (e.g., investor-owned utilities, municipally owned utilities, and other entities) to procure a certain share of their electricity from qualifying renewable resources. Entities that generate renewable electricity are required to be certified and tracked via RECs. These RECs are typically purchased with the electricity supplied and are subsequently retired by electricity suppliers to demonstrate compliance as part of the regulation via some regulating entity. A small number of states have incorporated different forms of RNG into their RPS programs. RPS programs do not typically employ a GHG emission reduction requirement, and as such, are generally silent on the issue of GHG emission account frameworks.

Voluntary programs
Some companies choose to prepare a voluntary GHG emission inventory for their operations. Companies do this for a variety of reasons, including to demonstrate leadership to customers, investors, and regulators, as part of a broader initiative to achieve GHG emission reduction targets, and to save money. Corporate sustainability and other Environmental, Social, and Governance (ESG) related initiatives are typically tied to the Greenhouse Gas Protocol Accounting and Reporting Standard. With the increasing number of commitments to net zero carbon emissions, including from many energy companies and investor-owned utilities, there is pressure to ensure that the GHG emission accounting approaches employed by stakeholders are consistent and transparent. The Greenhouse Gas Protocol is a commonly used set of reporting standards developed by the World Resources Institute and the World Business Council for Sustainable Development. A GHG Protocol-based approach is used by most corporations, but still incorporates many of the same sources and emission factors used by regulatory agencies. The GHG Protocol uses “Scope” levels to define the different sources and activity data included within an assessment. Instead of thinking in terms of geographic or sector-based boundaries, the GHG Protocol groups emissions in terms of direct and indirect categories through these Scopes. Figure B-1 shows how the GHG Protocol groups these emission sources by Scopes, and how they relate to an organization’s operations.

Figure B-1. Scopes for Categorizing Emissions Under the 2019 GHG Protocol



Organizations most often limit their assessment to Scope 1 and 2 emissions, which includes directly controlled assets. Scope 3 emissions reflect a lifecycle assessment approach that includes supply chain activities and associated, but not directly controlled, organizations.

There is no explicit mention of RNG in the GHG Protocol. Rather, there is guidance provided related to reporting GHG emissions from biomass fuels as a "special emissions accounting issue." The GHG Protocol requires corporations to report the direct carbon dioxide (CO_2) emissions from the combustion of biomass separately from the three scopes; however, the methane (CH_4) and nitrous oxide (N_2O) emissions from the combustion of biomass should be accounted for in the appropriate scope. Guidance documentation in support of the GHG Protocol provide many examples of biomass materials that can be used as fuels, including multiple feedstocks or processes that characterize RNG production, including landfill gas, forestry residues, manure, and biogas (produced from digestion, fermentation, or gasification of biomass). For example, if a company replaces 50 percent of its natural gas consumption with RNG, the company should report CO_2 emissions only on the remaining 50 percent of its conventional natural gas use and would report the CO_2 emissions from RNG consumption separately. And as a result, the inventory would show a 50 percent drop in CO_2 emissions.

The World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) initiated a process in January 2020 to develop new Greenhouse Gas Protocol guidance on accounting for land sector activities and CO_2 removals in corporate greenhouse gas inventories, building on the Corporate Standard and Scope 3 Standard.[92] WRI and WBCSD expect that draft guidance will be available for both pilot testing and review in June 2022, with final publication expected in early 2023. More specifically, the initiative seeks to update and develop new guidance on issues including land use, land use change, carbon

[92] GHG Protocol Land Sector and Removals Guidance, with more information available online at https://ghgprotocol.org/land-sector-and-removals-guidance.

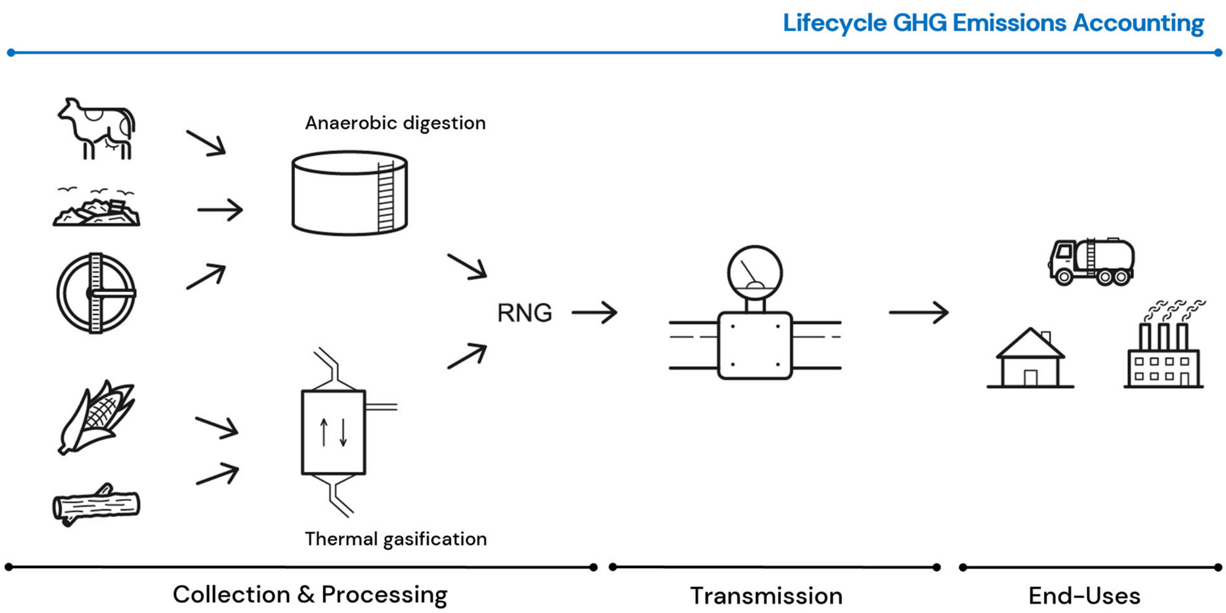
removals and storage, bioenergy and other biogenic products, and related topics. Biogas and RNG feedstocks are included in the initiative and will be addressed accordingly. ICF anticipates that the guidance from this initiative will have a significant impact on how corporate entities conduct GHG emission accounting as it relates to RNG and its role in decarbonization strategies.

Lifecycle GHG Emissions Accounting

As noted previously in Section 6, the lifecycle GHG emissions associated with the production of RNG vary depending on a number of factors including the feedstock type, collection and processing practices, and the type and efficiency of biogas upgrading. For the purposes of this report, ICF determined the lifecycle carbon intensity (CI) of RNG up to the point of pipeline injection. This includes feedstock transport and handling, gas processing, and any credits for the reduction of flaring or venting methane that would have occurred in absence of the RNG fuel production.

Figure B-2 (a repeat of Figure 6-1) offers a more detailed view of the various stages in RNG production, showing two different production methods and multiple feedstocks. As shown below, the stages of the combustion and lifecycle accounting approaches are broken out into three categories: Collection & Processing, Pipeline/Transmission, and End-Uses. However, the inputs considered within these stages vary between conventional natural gas and RNG, and even among different RNG feedstocks.

Figure B-2. Boundary Conditions of Lifecycle GHG Emissions Accounting for RNG



GHG emissions from RNG can be generated along the three stages of the RNG supply chain.

- *Collection and processing: Energy use required to produce, process, and distribute the fuel*. The energy used to produce, process, and distribute RNG is characterized here as: 1) feedstock collection and 2) digestion and processing related to anaerobic digesters, or synthetic gas (syngas) processing as it relates to thermal gasification.

- *Pipeline/transmission: Methane leaks primarily during transmission*. Methane leaks can occur at all stages in the supply chain from production through use but are generally focused on leakage during transmission. ICF limits our explicit consideration to leaks of methane as those that occur during transmission through a natural gas pipeline, as other methane losses that occur during RNG production are captured as part of efficiency assumptions.
- *End-use: RNG combustion*. The GHG emissions attributable to RNG combustion are straightforward: CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or carbon neutral. In other words, the GHG emissions are limited to CH_4 and N_2O emissions because the CO_2 emissions are considered biogenic.[93]

Understanding Avoided GHG Emissions

One of the key areas of confusion regarding the GHG emissions of RNG is linked to what is referred to as avoided GHG emissions—this is a concept that only occurs in lifecycle GHG emission accounting and is critical to understanding RNG's broader potential as a decarbonization strategy. Avoided GHG emissions are the GHG emissions that would have occurred under typical or business-as-usual conditions, in other words, if RNG had not been produced and used. There are three sources of GHG emissions that can be avoided:

- *Vented methane emissions.* For example, animal manure on a farm might otherwise be placed in an open lagoon that would vent or emit methane—a potent GHG. Similarly, food waste would likely be sent to a landfill where some methane would escape to the atmosphere; some would be captured and burned to convert most of the methane to carbon dioxide before it enters the atmosphere (i.e., flared).
- *Emissions displaced from the use of RNG intermediary products and coproducts*. In this case, some of the biogas produced in intermediate steps could be used to produce electricity and used to power processing equipment or other processes that require electrical energy in the RNG production supply chain, thereby displacing electricity from the grid.
- *GHG emissions attributable to combustion of conventional natural gas*. In most instances, RNG will be used as a substitute for conventional natural gas, therefore avoiding the emission that would have otherwise occurred from combusting conventional natural gas.

GHG accounting of avoided emissions can be dependent on the regulatory context. For instance, landfills above a certain size are required by federal law to collect and control landfill gas.[94] Therefore, there may be no avoided methane because landfill operators are already capturing methane that would have otherwise been emitted to the atmosphere. The avoided methane emissions are accounted by regulation. Therefore, any RNG produced via methane

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[93] IPCC guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas or biomass based RNG) should not be included when accounting for emissions in combustion – only CH_4 and N_2O are included. This is to avoid any upstream "double counting" of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance.
[94] The Clean Air Act regulations for landfills can be found in 40 CFR Part 60, Subparts Cc (https://www.ecfr.gov/current/title-40/part-60/subpart-Cc) and WWW (https://www.ecfr.gov/current/title-40/part-60/subpart-WWW)..

from a large landfill cannot count methane venting as avoided emissions in a lifecycle emissions accounting method since large landfills are required by law to capture and flare their methane emissions, as opposed to venting.

Avoided emissions are accounted for in a lifecycle accounting approach using negative numbers. These negative numbers simply represent the GHG emissions that were avoided—this is the appropriate convention. When determining a GHG emissions factor for RNG, there are cases when the avoided GHG emissions are greater than the GHG emissions, meaning that the GHG emissions factor is reported as a negative number. This is where the terms “carbon negative” arises from when discussing RNG from feedstocks (e.g., animal manure).

Table B-1 below shows the lifecycle carbon intensity values that ICF calculated using the GREET model for potential RNG projects in Michigan and compares that to conventional natural gas. ICF assumed that projects were located in Michigan and applied the corresponding GHG emissions factor associated with the RFC region from eGRID in the analysis. ICF did not assume that RNG projects would use on-site renewable energy to decrease the CI of the project. ICF identifies three categories in the table below:

- Extraction & Processing: This category includes the GHG emissions attributable to the energy used to operate anaerobic digesters, the energy required to upgrade biogas to RNG, and any avoided GHG emissions or displacement credits associated with a particular pathway.
- Transportation & Distribution: After the point of injection, RNG is transported through pipelines for distribution to end users. The CI of pipeline transmission depends on the distance between the gas upgrading facility and end use. GREET 2021 enables the user to choose from two approaches to fugitive methane emissions during transmission, referred to as the EPA and Hybrid approaches. These values range from 1.33 to 1.84 gCO_2e/MJ per *thousand miles* of transmission. For the sake of reference, Michigan’s Lower Peninsula is about 280 miles from north to south and 200 miles from east to west. For illustrative purposes, ICF used the Hybrid approach for fugitive methane emissions and assumed a transportation distance of about 160 miles.
- Stationary Combustion: The table also includes GHG emissions attributable to the combustion of natural gas and RNG in stationary applications. In the case of RNG, ICF assumed that the carbon dioxide emissions are biogenic and therefore zero, whereas the methane and nitrous oxide emissions are non-zero and are approximated at 0.05 g/MJ.

Table B-1. Estimated CI Values for RNG from Different Feedstocks (MI specific)

Fuel / Feedstock	Extraction & Processing	Transportation & Distribution	Stationary Combustion	Total
Conventional natural gas	8.27	4.11	50.35	62.72
Animal manure				
Dairy cows	-90.63	0.29	0.05	-90.29
Broilers & Turkeys	46.15	0.29	0.05	46.50
Beef	-12.24	0.29	0.05	-11.89
Swine	-235.00	0.29	0.05	-234.65
Food waste	-99.22	0.29	0.05	-98.87
Landfill gas	10.91	0.29	0.05	11.26
WRRF	-94.45	0.29	0.05	-94.10
Thermal gasification Agricultural residue Energy crops Forestry residue MSW	50-55	0.29	0.05	50.34-55.34

ICF notes the following about these CI estimates:

- The lowest carbon intensities are from feedstocks that prevent the release of fugitive methane, such as the collection and processing of dairy cow manure, beef manure, and swine manure, the diversion of food waste from landfills, or the beneficial use of gas from WRRFs.
- Agricultural residue, energy crops, forestry products and forestry residues, as well as MSW all have the same CI range based on the thermal gasification process required to create biogas from biomass. This is an energy-intensive process, but inclusion of renewables and co-produced electricity on-site can reduce the emissions impact of gas production.

The sensitivity of fugitive GHG emissions, particularly along gas pipelines is highlighted by comments received by stakeholders:

- Some stakeholders asserted that if RNG is produced and consumed locally, that it could eliminate or significantly reduce the use of interstate pipelines where fugitive emissions occur and that RNG development is not associated with the scale of fugitive emissions that are typical of oil and gas wells at the point of production.
- Other stakeholders noted that Michigan may have high pipeline leakage rates due to the age and materials of its pipelines.

ICF's analysis using the GREET model supports the concept that RNG has the potential to reduce fugitive GHG emissions by transport the gas over a shorter distance. ICF estimates that transportation and distribution of RNG will yield an average carbon intensity of about 0.3 g/MJ for Michigan-based projects, whereas conventional natural gas traveling longer distances yields a carbon intensity of about 4.1 g/MJ.

To be clear, these stakeholder comments were intended to emphasize the importance of using a lifecycle accounting approach as it relates to the GHG emissions of RNG. However, as stated earlier, nothing in this report should be misconstrued as an endorsement for or against one GHG emissions accounting approach over another as it relates to a policy structure.

To conduct a GHG emission reduction assessment using the lifecycle accounting approach outlined here, one would simply need to add the upstream GHG emissions factors outlined previously, determine a reasonable estimate for the average distance that RNG will be distributed through the pipeline to account for fugitive methane emissions, and include the GHG emissions at the point of combustion—which should be limited to N_2O and CH_4 emissions based on current GHG emission accounting conventions related to RNG combustion.

Appendix C

State-Level RNG Polices

Today, many state-level policies are in place that are helping to shape the outlook for RNG beyond transportation. The information included in the table on the following pages provides information on these policies, including the state in which the bill was enacted, a bill summary, and key programmatic components such as supply, production or interconnection, cost recovery for gas utilities, and end-user benefits.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
Arkansas SB 136	Amends state law related to gas rates allowing the PSC to consider utility purchase of natural gas or natural gas alternatives, such as RNG and hydrogen, as an operating expense if the purchase is in the public interest.	No reference	No reference	No reference	No reference
Colorado SB 20-013	Requires gas utilities to file a clean heat plan with the PUC. The targets are a four percent reduction below 2015 GHG emission levels by 2025 and 22 percent by 2030.	Within the overall targets, RNG may only account for one percent of the 2025 target and five percent of the 2030 target.	No reference	No reference	Reduce GHG emissions, with a focus on cost-effectiveness.
Minnesota *Natural Gas Innovation Act*	Allows a natural gas utility to submit an “innovation plan” for approval by the MN PUC to reduce natural gas use.	Eligible technologies include RNG, renewable hydrogen, energy efficiency, and other innovative technologies.	No reference	The maximum allowable cost will start at 1.75% of the utility's revenue in the state and could increase to 4% by 2033, subject to review and approval by the PUC	Reduce GHG emissions; diversify energy resources; promotes innovation; increased renewable energy consumption; and improve waste management.
Oregon SB 98	Allows natural gas utility to make “qualified investments” and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail customers.	Establishes large/small RNG programs and to make “qualified investments” and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail natural gas customers.	RNG infrastructure means all equipment and facilities for the production, processing, pipeline interconnection, and distribution.	PUC shall adopt rules establishing a process for utilities to fully recover costs. Cost of capital established by PUC from most recent rate case. Affiliates not prohibited from making a capital investment in a biogas production project. Restricted from making additional qualified investments without the approval of the PUC if the	Reduced emissions. RNG portfolio ranging from 5% between 2020 and 2024 to 30% between 2045 and 2050.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
				program annual costs exceed 5% of the utility's total revenue requirement in an individual year.	
Washington HB 1257	Required each gas company to offer by tariff a voluntary renewable natural gas service available to all customers.	To replace any portion of the natural gas that would otherwise be provided by the gas company. Customer charge for an RNG program may not exceed 5% of the amount charged to retail customers for natural gas.	No Reference	No Reference	Commission must assess whether the gas companies are on track to meet a proportional share of the state's GHG reduction goal.
Nevada SB 154	Authorized natural gas utilities to engage in RNG activities and to recover the reasonable and prudent costs of such activities, including the purchased of and production of RNG.	Requires a public utility to "attempt" to incorporate RNG into its gas supply portfolio. Gas which is produced by processing biogas or by converting electric energy generated using renewable energy into storable or injectable gas fuel in a process commonly known as power-to-gas or electrolysis.	Activities which may be approved: contracting with a producer of RNG to build and operate an RNG facility; extending the transmission or distribution system to interconnect with an RNG facility; purchasing gas that is produced from an RNG facility whether the gas has environmental attributes or not.	Utility applies to the Commission for approval of a reasonable and prudent RNG activity that will be used and useful. Must meet one or more: the reduction or avoidance of pollution or GHG; the reduction or avoidance of any pollutants that could impact waters in the state; the alleviation of a local nuisance within the state associated with the emission of odors.	Sell gas from RNG facility directly to the customer. Providing customers with the option to purchase gas produced from an RNG facility with or without environmental attributes. Utility shall attempt to incorporate RNG in its gas supply portfolio: By 2025, not less than 1% of the total amount of gas sold; by 2030, not less than 2%; by 2035, not less than 3%.
California SB 1440	Requires the CPUC to establish biomethane procurement goals or targets on natural gas IOUs to further decarbonize the state's natural gas sector.	Adopted a 2025 target of 17.6 BCF and a 2030 target of 72.8 BCF of RNG.	To be eligible, the biomethane needs to be delivered through a common carrier pipeline that physically flows within California, or toward the end user in California for which	Authorize procurement contracts for a minimum of 10 years and a maximum of 15 years.	A limited biomethane procurement program would help the state reduce methane and ensure that California's

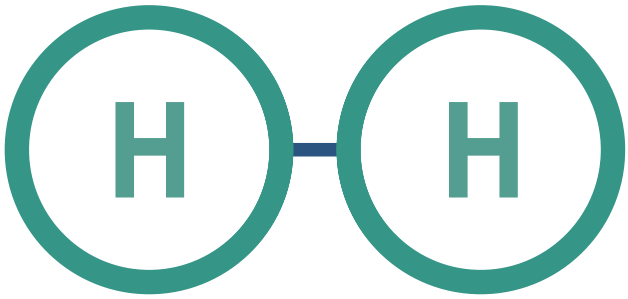
State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
	Stipulates that the goals and targets need to be a cost-effective means of achieving reductions in short-lived climate pollutants and other GHG emission reductions.		the biomethane was produced.		climate policies are met.
California AB 1900	Established a program beginning in 2015 that provided $40M for RNG interconnection infrastructure. The bill was intended to address the barriers to allowing RNG to be injected into pipelines and break down barriers to using instate RNG—all while ensuring the supply was non-hazardous to human health.	The bill required the California EPA to compile a list of constituents of concern that could pose risks to human health and that are found in biogas at concentrations that significantly exceed the concentrations of those constituents in natural gas.	A part of this bill would require the PUC to adopt standards to ensure pipeline integrity and safety. The PUC would also adopt pipeline access rules to ensure nondiscriminatory access to all pipeline systems for physically interconnecting with the gas pipeline system and effectuating the delivery of gas.	No reference.	As a health safety initiative, the bill required the PUC to specify the maximum amount of vinyl chloride that may be found in landfill gas.
Utah HB 107	Authorizes gas utilities to establish natural gas clean air programs that promote sustainability through increasing the use of renewable natural gas if those programs are deemed to be in the public interest.	In determining whether a project is in the public interest, the Public Service Commission (PSC) shall consider to what extent the use of renewable natural gas is facilitated or expanded by the proposed project; potential air quality improvements associated with the proposed project; whether the proposed project could be provided by the private sector or would be viable without the proposed incentives; whether any proposed incentives were offered to all similarly situated	No reference.	The PSC may authorize large-scale utilities to allocate up to $10M annually to a specific sustainable transportation and energy plan. Elements include an economic development incentive rate; R&D of efficiency technologies; acquisition of non-residential natural gas infrastructure behind the utility's meter; the development of communities that can reduce GHG and NOx emissions; a natural gas renewable energy project;	Reduction of greenhouse gases and NOx emissions.

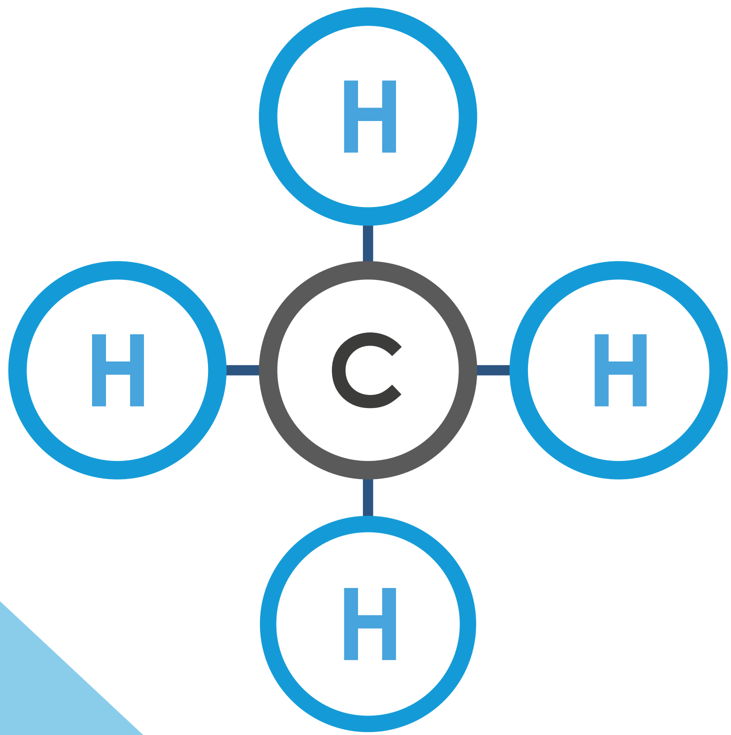
State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
		potential partners and recipients; and potential benefits to ratepayers.		a commercial line extension program; or any other technology program. Electric utilities were previously authorized to have similar programs. If the PSC finds that a gas corporation's request for an NGV rate/clean air programs is less than the full cost of service, remaining costs may be spread to other customers. A previous statute authorizes recovery of expenditures for the construction, operation, and maintenance of natural gas fueling stations and related facilities.	
Vermont PUC Docket# 8667	VT Public Utility Commission authorized a renewable natural gas program for the sale of RNG to customers on a voluntary basis and optional RNG tariff service.	Vermont Gas stated they were seeking to source RNG from landfill gas projects.	Supply from Lincoln and landfill gas projects outside Vermont would be received through the Trans-Canada Pipeline system.	Requires Vermont Gas to file a formal tariff including proposed rates once it has procured RNG in sufficient amounts for estimated customer demand. Adder price for each scf of RNG will be equal to the average RNG commodity cost to VGS less the average commodity cost of natural gas. Also, if Vermont Gas' RNG supply exceeds customer demand, they must first seek to sell the excess at wholesale, and if necessary may seek to flow any remaining inventory amounts through	Successful implementation can help meet the State's renewable energy policy objectives. Assessment of the voluntary program will assist in determining the feasibility of incorporating RNG as a portion of Vermont Gas' supply mix in the future.

State / Bill	Brief Description	Supply	Production / Interconnection	Cost Recovery	End-User Benefit
				a rate case as part of its cost of service.	
Tennessee SB 1959 Tennessee Natural Gas Innovation Act	Authorizes a public utility to request, and the TN PUC to authorize, a mechanism to recover the costs related to the use or development of infrastructure to facilitate use of innovative natural gas resources.	"Innovative natural gas resources" include, but are not limited to, farm gas, biogas, renewable natural gas, hydrogen, carbon capture, qualified offsets, renewable natural gas attributes, RSG, and energy efficiency resources.	No reference	Limits the incremental rate adjustment due to the investment in innovative natural gas resources at 2% of a utility's latest approved annual revenue requirement.	Reduce GHG emissions; diversify energy resources; promotes innovation; increased renewable energy consumption; and improve waste management.
Virginia HB 558	Allows utilities to make investments in eligible infrastructure costs for a variety of projects, including biogas development assuming it meets certain emissions intensity reductions.	No reference		Utilities can recover eligible infrastructure costs through the gas component of the rate structure or other recovery mechanism approved by the Commission.	

Hydrogen

A decarbonisation route for heat in buildings?





LETI

Is hydrogen a decarbonisation route for heat in buildings?

Summary

Hydrogen fuel is often touted as a viable solution to assist in meeting our UK net zero carbon targets. LETI have therefore sought to investigate this further and examine to what extent Hydrogen is likely to be used, either in part or full to accompany decarbonisation of the electricity grid.

This document acts as a primer for those seeking clarity on the likelihood of hydrogen becoming a means of heat delivery for buildings via the pre-existing gas pipe network. It is based on an extensive published document review from a broad range of viewpoints. A summary of our key findings is provided below, with extended research presented on the following pages.

When considered holistically, it seems unlikely that zero carbon hydrogen supplied via a re-purposed gas mains network will be available, for the vast majority of buildings, for the foreseeable future.

→ **Which hydrogen** – 'Green' hydrogen from renewable power electrolysis is truly zero emissions. However, the UK gas supply industry[1] advocates 'Blue' hydrogen[2] manufactured from methane with carbon capture of its high emissions using yet to be proven at scale carbon capture and storage technology.

→ **Efficiency** – Hydrogen conversion, delivery and combustion has between a third and one sixth the efficiency of the alternatives[3] (figure 1). Where it does have a clear benefit, for energy storage, this is more efficiently done centrally to serve peak electricity power generation without needing a general gas grid switch over.

→ **Implementation** – The lack of tangible benefits or engagement with the millions of building occupier/owners casts serious doubts on the practicality of a gas switch over. There is a noticeable lack of proposals to guarantee and accept liabilities for in-building gas pipework switch over. Meanwhile the hydrogen dosing of natural gas appears to be as much a technological dead-end as biodiesel dosing of automotive fuel proved to be.

→ **Costs** – Funding for a second national energy grid upgrade, incorporating new infrastructure technology unproven at scale is a major delivery risk. Along with a required 150%[4] increase in primary energy generation this appears highly questionable. Funding this from government or investors seems unlikely when viewed alongside the alternative of rapidly falling renewable electricity costs (such as windfarms)[5]. Expecting consumers to pay will unduly penalise those in society least able to pay.

When blue hydrogen, supplied via the gas network, is compared to the use of heat pumps there is a stark difference in efficiencies. Begging the question - why consider or pursue hydrogen for the heating of UK homes? We should be considering more effective way to decarbonise our buildings?

Of note, we have found that the public discourse on hydrogen appears severely unbalanced, with gas supply industry in particular "over-selling 'green-gas' to policy makers in order to protect their interests"[6].

LETI concludes it is unlikely that zero carbon hydrogen supplied via a re-purposed gas mains network will be available for the vast majority of buildings, for the foreseeable future.

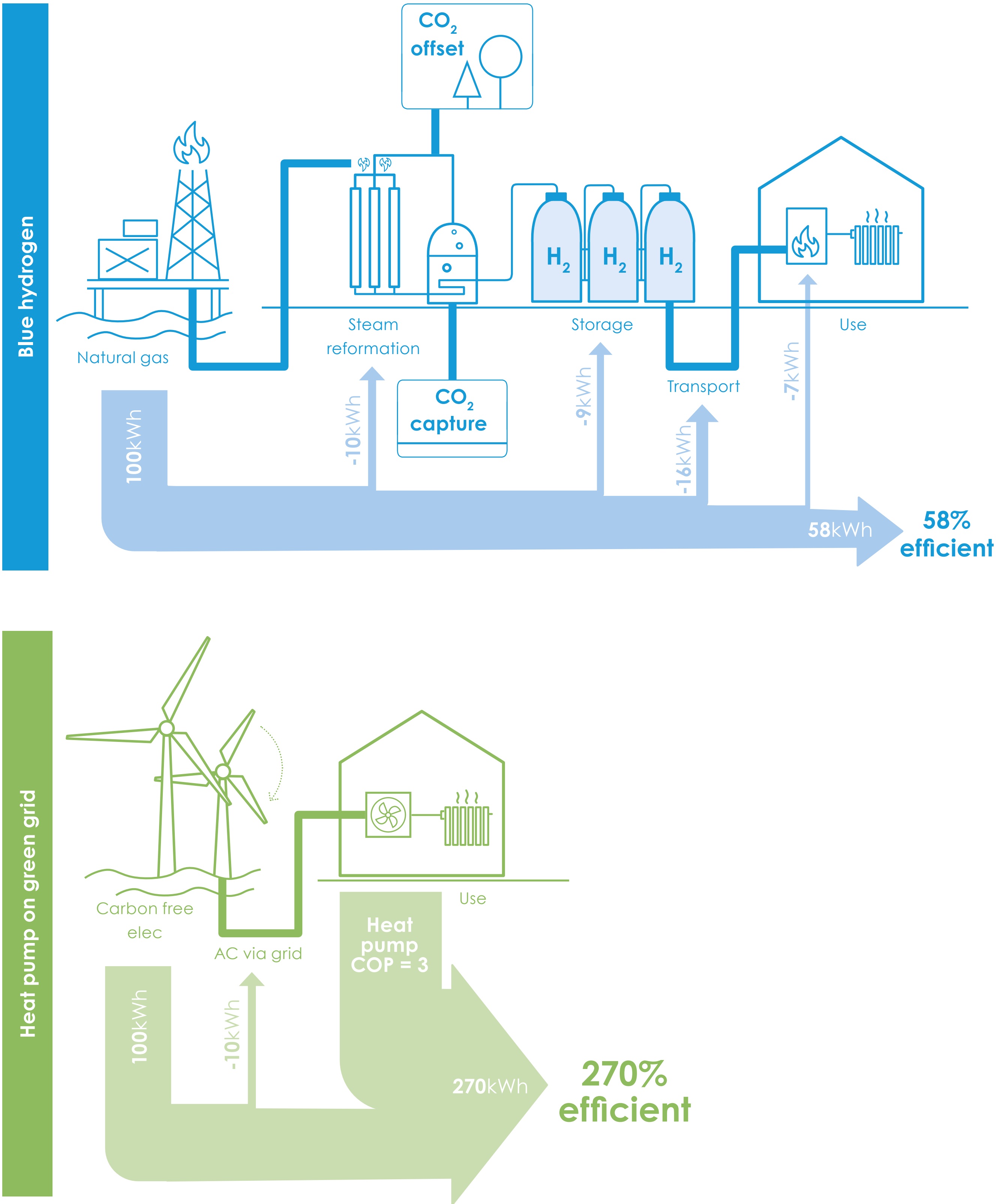


Figure 1 - The difference between blue hydrogen and heat pumps on a green grid (useable heat output compared with energy sourced for input to the grid).

Data source - Prof David Cebon[7]

Heat

Decarbonising heat, particularly with peaks at about four times the current electrical grid capacity[8], is a challenge. Whilst a switch to all-electric heat pumps can address much of this, it is by no means a fully resolved route forward[9]. As an alternative, the gas supply industry is advocating repurposing of the (otherwise obsolete) natural gas network to supply hydrogen for heat[10].

The Committee on Climate Change (CCC) has suggested that hydrogen might be available for peak demand using hybrid heat pumps (HHP)[11]. While HHPs were originally envisaged as combined units[12], practicalities now suggest separate boilers and air source heat pumps with integrated controls[13] would be required. There is currently no clarity on the route to market for these.

Previous ideas of domestic gas fuel cells seem to have fallen away, not least because their output does not match domestic heat to electricity ratios[14]. Although not specifically referred by the CCC, there seems to be an increasing push towards replacement domestic boilers that can be converted on-site from natural gas to hydrogen gas[15].

Blue Hydrogen

The gas supply industry[16] is advocating 'Blue' hydrogen manufactured by massively scaling up the process of natural gas steam reformation (figure 2). This process does however emit CO_2 as well as having upstream methane greenhouse gas (GHG) leakages[17]. Large-scale carbon capture and storage (CCS) technology is proposed to capture some 90% of these CO_2 emissions[18]. Additional bio-sequestration or similar would also be required to remove the remaining 10% of CO_2 for 'Blue' hydrogen to become zero carbon[19] (figure 3). There are significant uncertainties in developing, up-scaling and deploying these technologies. In addition, large volume storage of hydrogen for the winter peak demands would be required. Long term storage of captured carbon dioxide would also need to be developed. It seems likely that for the period until CCS is proven and implemented at scale, significant GHGs would be emitted before blue hydrogen can be delivered.

Green Hydrogen

'Green' hydrogen is created using renewable electricity with an electrolysis process and hence without the consequential CO_2 emissions[20] (figure 4). Interestingly, Germany's new hydrogen national strategy[21] has decided not to consider 'Blue' hydrogen for either the short term or the long term, instead focusing on 'Green' hydrogen. It also acknowledges they expect to become dependent on hydrogen imports because of insufficient indigenous renewable energy sources. They have therefore concluded that hydrogen should be focused on uses where portability, storage and intensity of energy is critical and where there are therefore few alternatives (e.g. high temperature industry, heavy and long distance transport etc.).

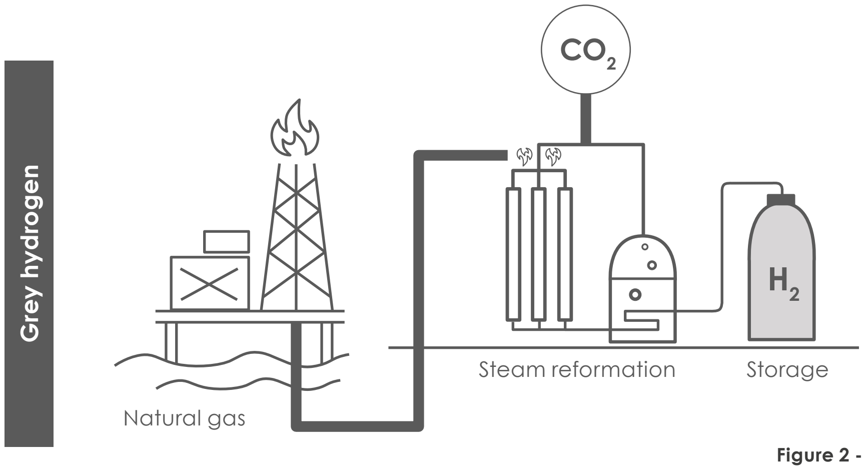


Figure 2 - Grey hydrogen, how hydrogen is currently made

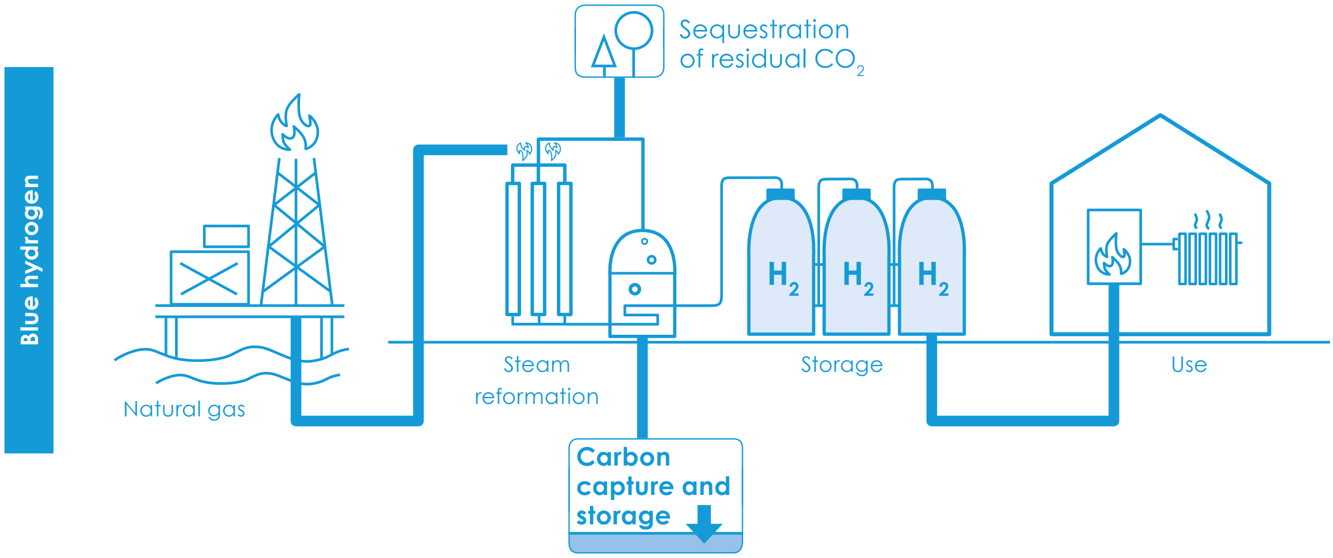


Figure 3 - Blue hydrogen, as advocated by the gas supply industry

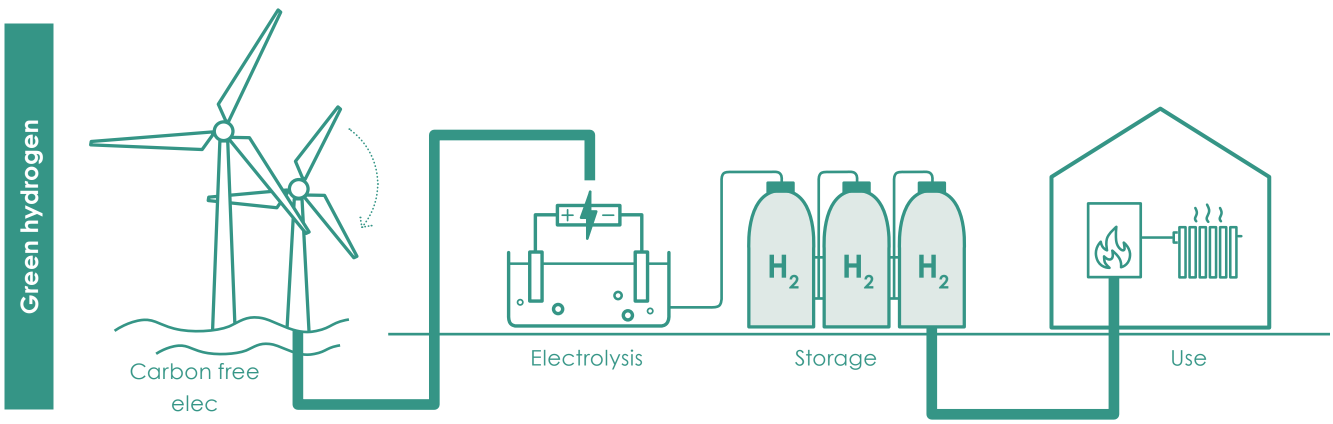


Figure 4 - Green hydrogen, made from renewable energy

Implementation

Hydrogen trials are currently being conducted[22] to address gas grid switch over issues. A switch over is expected to involve replacing primary distribution steel mains, additional pumping, reuse of polyethylene local distribution, new end-use appliances, and selective component replacement, as well as proving of the re-purposed system. However, what appears to be unresolved is the issue of who accepts liability for re-purposing of pre-existing (largely concealed) pipework inside most dwellings and other buildings.

The proposal to dilute natural gas with 20% hydrogen for the start of a route to zero carbon seems to be a technological dead-end similar to biodiesel dosing of diesel. Looking ahead further on switching the gas grid entirely to 'Green' hydrogen would need some 50% additional renewable electricity annually[23], due to its relatively poor overall delivery efficiency. How this might be achieved is currently unresolved, raising the potential of permanent investment lock-in to the GHG emissions of a 'Blue' hydrogen road map.

Hydrogen as an energy delivery vector (carrier) is relatively inefficient compared with using renewable electricity with heat pumps[24], as illustrated in figures 5 and 6. Hydrogen could provide useful renewable energy storage until needed for winter peaks. However, this can be more efficiently implemented using re-purposed combined cycle gas turbine (CCGT) power-stations without needing wider gas grid conversion[25].

The gas supply industry quotes the 1970s natural gas grid switch over as a precedent[26]. This was carried out at no cost to the consumer[27] and switched to a significantly cheaper new fuel[28]. It triggered extensive consumer complaints[29] and call backs that were largely unreported at the time (in the absence of social media). The current smart meter changeover track record does not bode any better in this regard[30].

The building side of a gas grid switch over is in the hands of millions of building occupier owners, for whom energy is not a core business. Therefore, decisions by them to permit a switch over, or not, are likely to be made using non-energy/carbon rationale (e.g. cost, amenity, expectations and disruption). However, the new manufactured hydrogen is expected to cost more than natural gas, particularly if the cost of building pipework and appliance conversion is amortised within it[31]. Issues like responsibility for disruption, redecoration and liability for re-purposing dwelling pipework are unresolved. Plainly there will be a significant communication and education challenge before the public would support a switch over from natural gas[32]. As has been illustrated by the Green Deal, lack of appropriate alignment with these building stakeholders can bring a national programme to a halt[33].

There does, however, seem to be a sounder logic of fewer high-intensity gas users connecting to a smaller network. This scenario would include:

- Peak CCGT power stations
- High temperature industry
- Long-haul aviation and heavy lift haulage
- Distribution to local consumer networks in the immediate vicinity [34].

A key feature for these scenarios would be diluting the investment cost within a wider service offering, before reaching consumers.

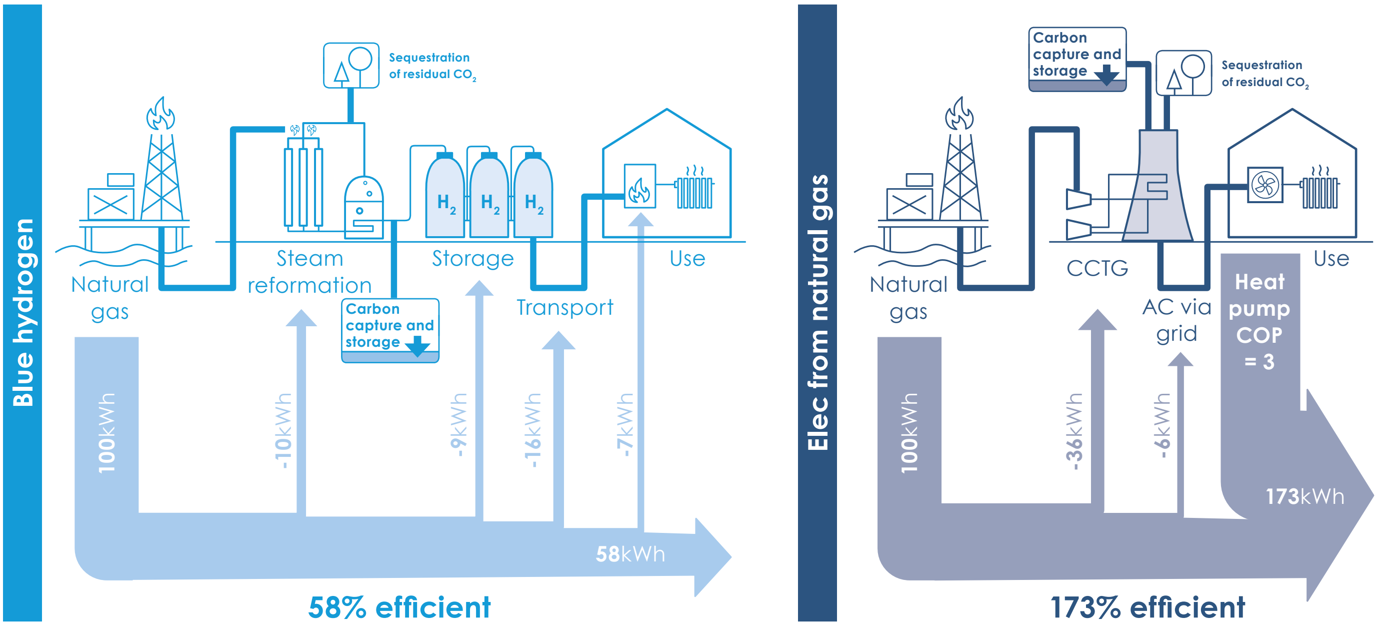


Figure 5 - The difference between blue hydrogen and electricity from natural gas supplying a heat pump

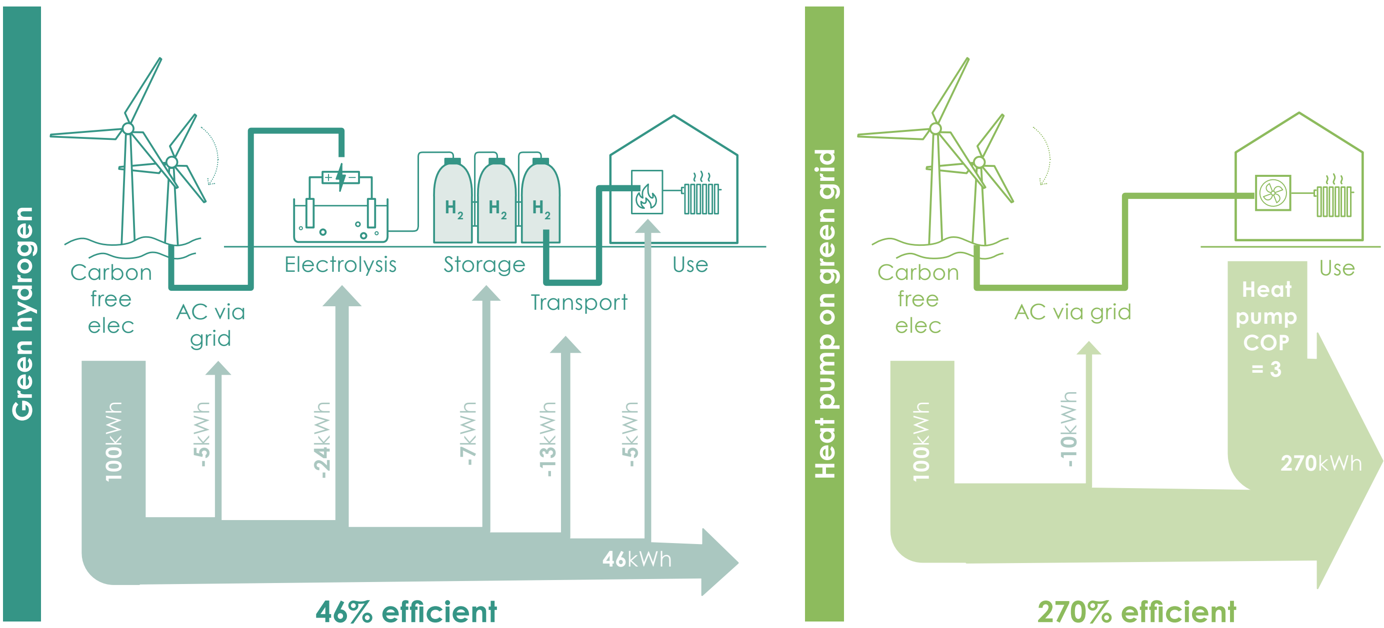


Figure 6 - The difference between green hydrogen and a heat pump supplied by a green grid

Data source - Prof David Cebon[7]

Timescale and finance

The proposed timescale for implementing Blue hydrogen with its CCS[35] does not align with LETI recommended rates of building decarbonisation[36]. If 'Blue' hydrogen remains the gas supply industries proposed end state, there is a significant risk that re-purposing the gas grid using new unproven technology at scale could prove less feasible than previously thought. By that time, the required scale of carbon offsetting is unlikely to be available at reasonable cost[37]. This would leave little time to implement alternatives, and in the midst of a climate emergency we should be leaving little to chance.

The cost of gas grid conversion is said to be of a similar magnitude to an all-electric switch over[38]. That said, paying for both conversions serving similar purposes would appear to be a poor investment. The hydrogen conversion costs also appear to be far more dependent on revenue from year-round large-scale adoption and high consumption of hydrogen[39], apparently at odds with the CCC suggestions for it serving just peak demands[40].

Unlike an all-electric switch over, there are significant hydrogen cost uncertainties, like the yet to be proven CCS[41]. This makes it a fundamentally different investment proposition. For the electrical switch over, private investment largely funds new wind power generation based on falling capital costs with relatively low operating costs, providing proven investment returns[42]. On the other hand, hydrogen manufacture operating costs will be inherently higher than natural gas[43], generate less capital return to investors and at a higher investment risk level given the unproven technology and up-scaling needed. Consequently, a gas switch over is likely to require significantly more taxpayer funding from already stretched public budgets. Simply passing this scale of costs directly through to consumers is unlikely to be acceptable because it includes those in society least able to afford it.

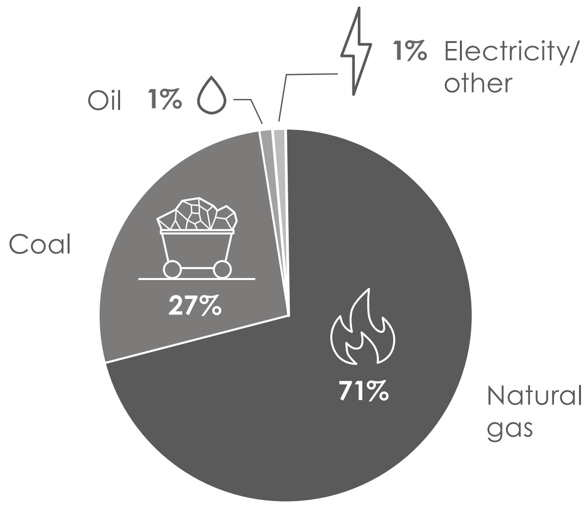


Figure 7 - Current global dedicated hydrogen production, energy input by source. Total current global hydrogen production is 44% of UK current gas demand.

Data source - IEA (2019)

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The views expressed in this document do not necessary represent the views of the organisations to which contributors have affiliations.

References

[1] The term 'Gas supply Industry' has been used in this paper to refer collectively to organisations involved in the gas sourcing, gas primary and secondary distribution, retailers to the consumers, boiler manufacturers, and consultants employed by these parties. It should be noted that all parts of these organisations hold the same views.

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This is a climate emergency

We are in a climate emergency, and urgently need to reduce carbon emissions. Here in the UK, 49% of annual carbon emissions are attributable to buildings. Over the next 40 years, the world is expected to build 230 billion square metres of new construction – adding the equivalent of Paris to the planet every single week – so we must act now to meet the challenge of building net zero developments.

The London Energy Transformation Initiative have developed this short guide to provide information for the built environment - setting out a definitive journey, beyond climate emergency declarations, into a net zero carbon future.

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admin@leti.london

Feb 2021

Clean Hydrogen Ladder Version 5.0

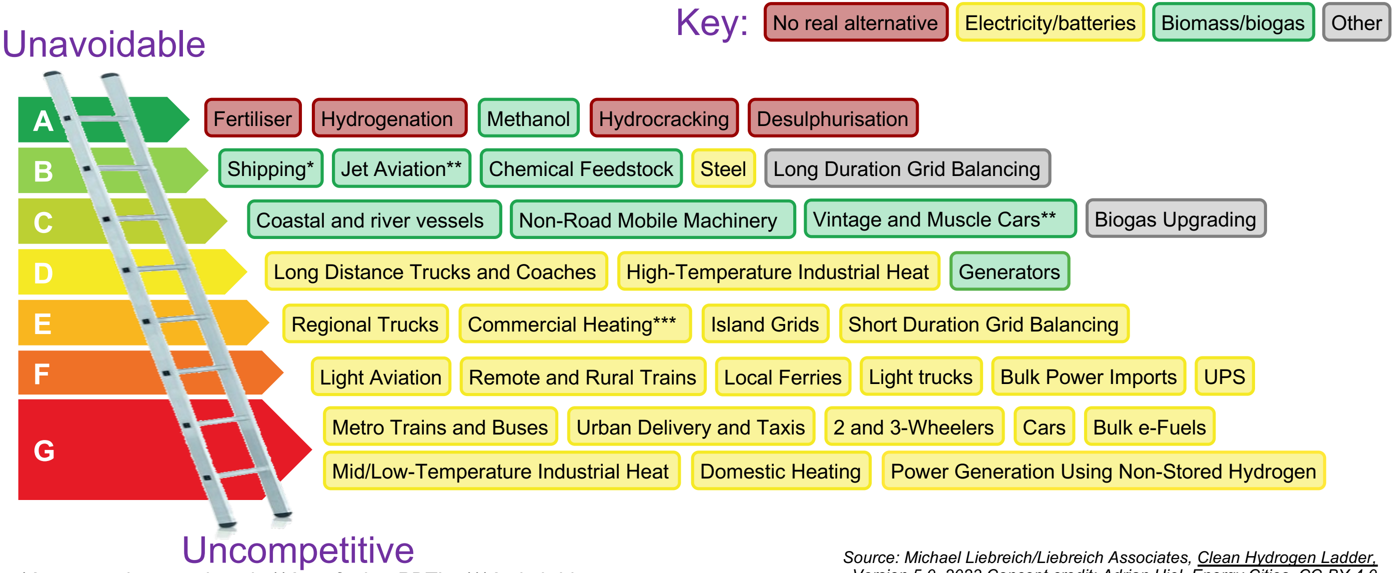
19 October 2023

Michael Liebreich
Founder and CEO
Liebreich Associates

For more information on the decisions behind the Ladder, please read the launch document

Hydrogen Ladder 5.0

Liebreich Associates



*As ammonia or methanol **As e-fuel or PBTL ***As hybrid system

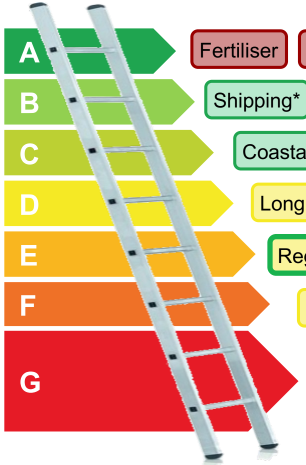
Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023. Concept credit: Adrian Hiel, Energy Cities.

Hydrogen Ladder 5.0 – Promotions (3)

Liebreich Associates

Key: No real alternative | Electricity/batteries | Biomass/biogas | Other

Unavoidable



- A: Fertiliser | Hydrogenation | Methanol | Hydrocracking | Desulphurisation
- B: Shipping* | Jet Aviation** | Chemical Feedstock | Steel | Long Duration Grid Balancing
- C: Coastal and river vessels | Non-Road Mobile Machinery | Vintage and Muscle Cars** | Biogas Upgrading
- D: Long Distance Trucks and Coaches | High-Temperature Industrial Heat | Generators
- E: Regional Trucks | Commercial Heating*** | Island Grids | Short Duration Grid Balancing
- F: Light Aviation | Remote and Rural Trains | Local Ferries | Light trucks | Bulk Power Imports | UPS
- G: Metro Trains and Buses | Urban Delivery and Taxis | 2 and 3-Wheelers | Cars | Bulk e-Fuels | Mid/Low-Temperature Industrial Heat | Domestic Heating | Power Generation Using Non-Stored Hydrogen

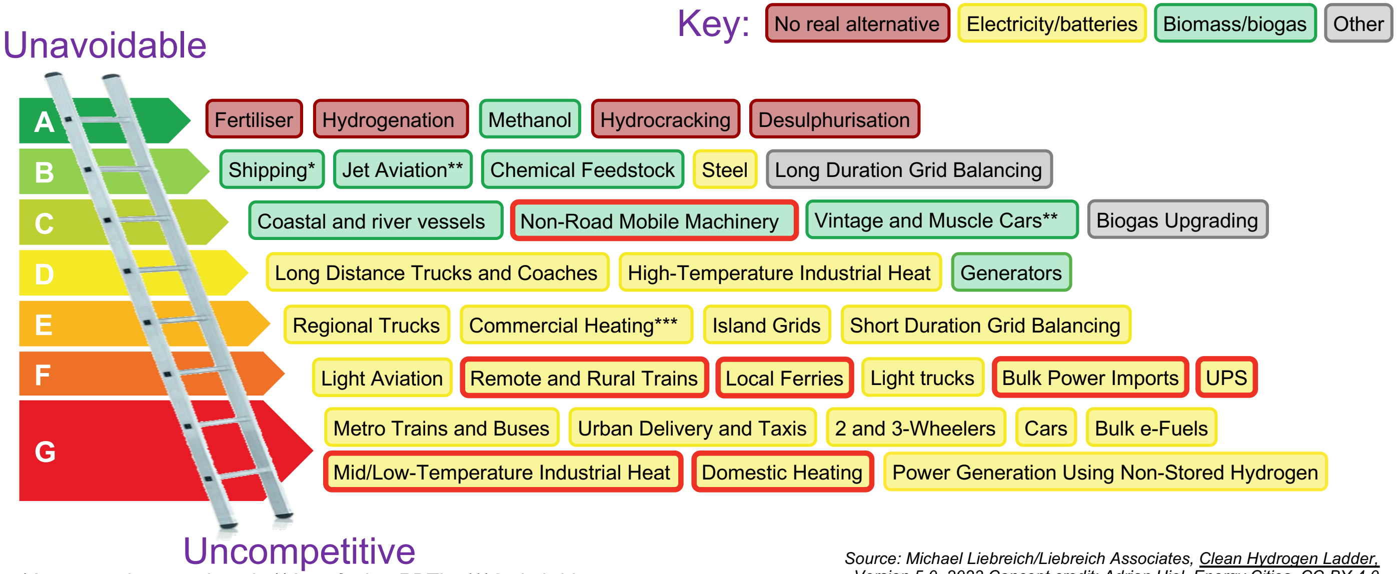
Uncompetitive

*As ammonia or methanol **As e-fuel or PBTL ***As hybrid system

Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023. Concept credit: Adrian Hiel, Energy Cities. CC-BY 4.0

Hydrogen Ladder 5.0 – Demotions (7)

Liebreich Associates

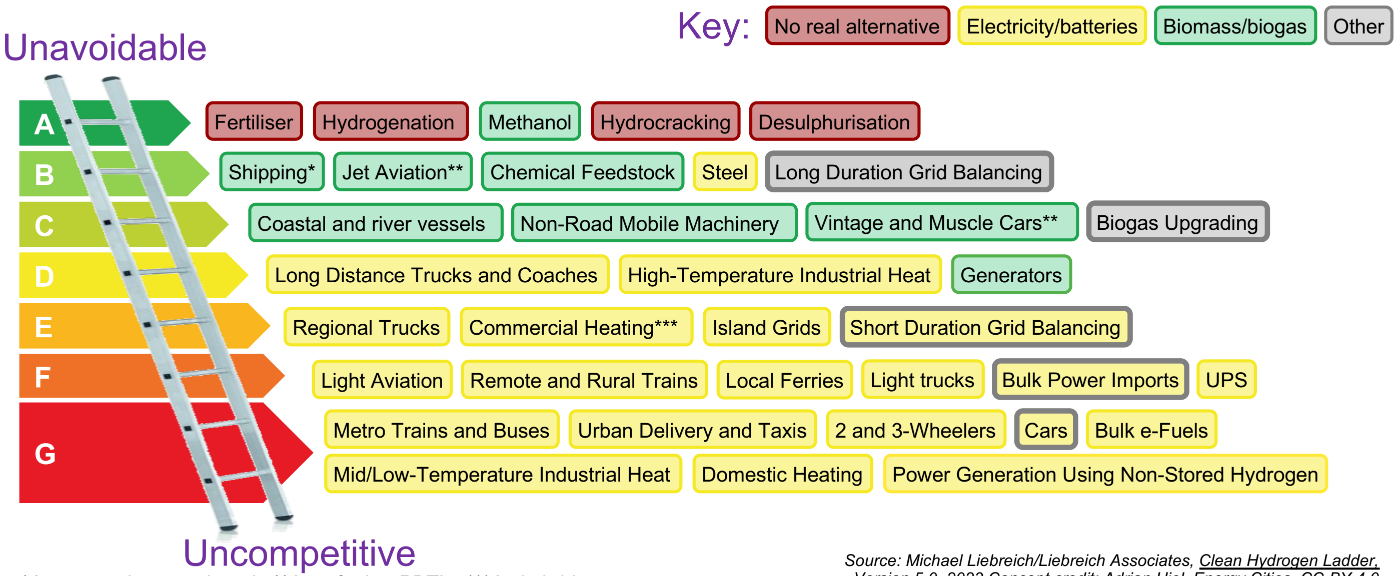


*As ammonia or methanol **As e-fuel or PBTL ***As hybrid system

Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023. Concept credit: Adrian Hiel, Energy Cities. CC-BY 4.0

Hydrogen Ladder 5.0 – Wording changes (5)

Liebreich Associates

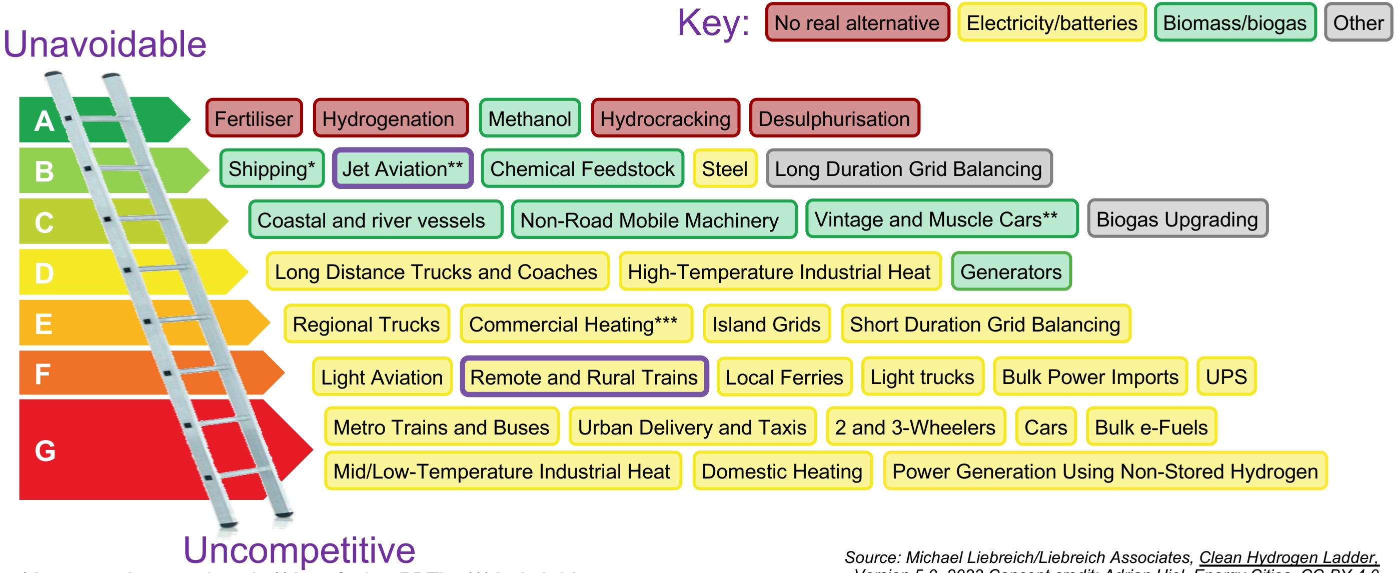


**As ammonia or methanol   **As e-fuel or PBTL   ***As hybrid system*

Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023.Concept credit: Adrian Hiel, Energy Cities.

Hydrogen Ladder 5.0 – Use cases combined (5 to 2)

Liebreich Associates



*As ammonia or methanol **As e-fuel or PBTL ***As hybrid system

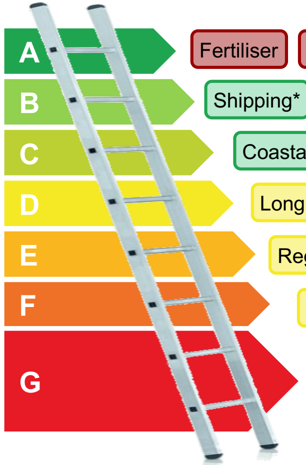
Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023. Concept credit: Adrian Hiel, Energy Cities. CC-BY 4.0

Hydrogen Ladder 5.0 – New or partially new uses (4)

Liebreich Associates

Key: No real alternative | Electricity/batteries | Biomass/biogas | Other

Unavoidable



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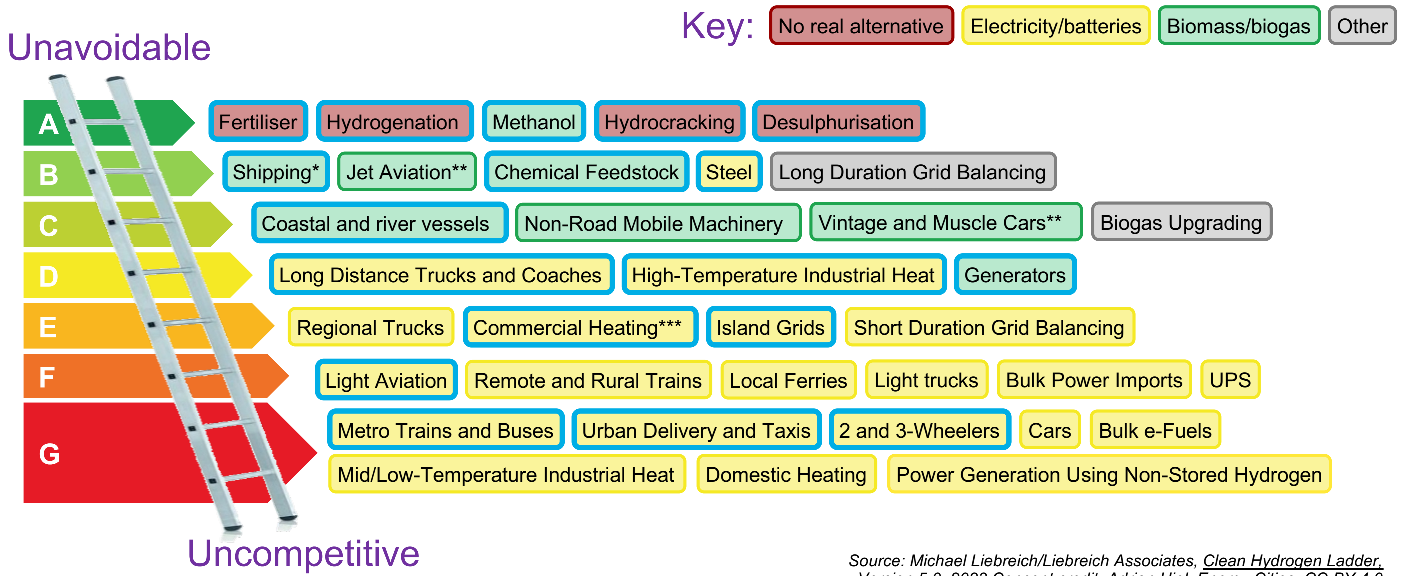
Uncompetitive

*As ammonia or methanol **As e-fuel or PBTL ***As hybrid system

Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023. Concept credit: Adrian Hiel, Energy Cities.

Hydrogen Ladder 5.0 – Unchanged (18)

Liebreich Associates



*As ammonia or methanol   **As e-fuel or PBTL   ***As hybrid system

Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023. Concept credit: Adrian Hiel, Energy Cities. CC-BY 4.0

Clean Hydrogen Swiss Army Knife

Liebreich Associates

Chemicals & Processes

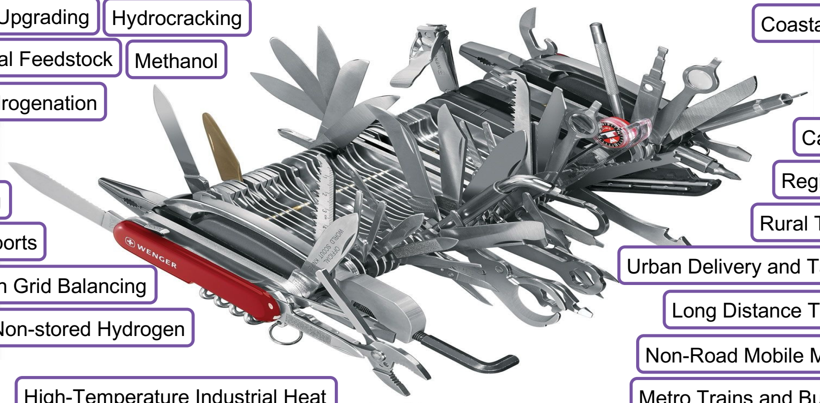
Desulphurisation
Fertiliser
Bulk e-Fuels
Steel
Biogas Upgrading
Hydrocracking
Chemical Feedstock
Methanol
Hydrogenation

Aviation & Shipping

Local Ferries
Light Aviation
Shipping
Aviation (jet fuel)
Coastal and River Vessels

Power System

Long Duration Grid Balancing
Generators
Bulk Power Imports
Island Grids
Short Duration Grid Balancing
Power Generation from Non-stored Hydrogen
UPS



Land Transportation

Cars
Light Trucks
Regional Trucks
2 and 3-Wheelers
Rural Trains
Remote and Rural Trains
Urban Delivery and Taxis
Vintage and Muscle Cars
Long Distance Trucks and Coaches
Non-Road Mobile Machinery
Metro Trains and Buses

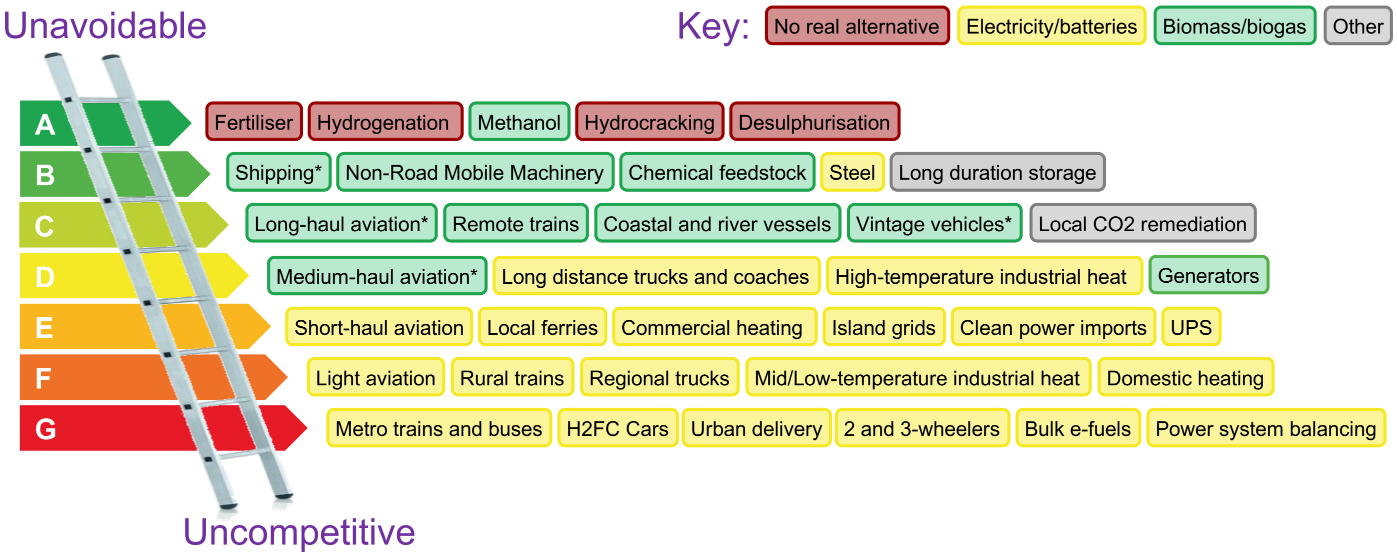
Heat

High-Temperature Industrial Heat
Mid/Low Temperature Industrial Heat
Domestic Heating
Commercial Heating

Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 5.0, 2023.Concept credit: Adrian Hiel, Energy Cities. Image: Wenger (concept credit: Paul Martin). CC-BY 4.0

Hydrogen Ladder 4.1 – For reference

Liebreich Associates



Source: Michael Liebreich/Liebreich Associates, Clean Hydrogen Ladder, Version 4.1, 2021. Concept credit: Adrian Hiel, Energy Cities.

** Most likely via ammonia or e-fuel rather than H2 gas or liquid*

Versions

Liebreich Associates

4.1: Added Generators; renamed Off-Grid Vehicles as Non-Road Moving Machinery

4.1a: Standardised the Source line; Clarified Terms and Conditions of Use and add an approved-format credit

5.0: Significant update: promotions (3); demotions (7); wording changes (5); use cases combined (5 into 2); new or partially new use cases (4); entirely unchanged (18); changed wording or combined, but unchanged row (5). Read the launch document for details.

Source: Liebreich Associates

Liebreich Associates

Terms and conditions of use

Disclaimer

The information represented in the Clean Hydrogen Ladder reflects the best judgement of Michael Liebreich based on decades of work on the technologies, policies, economics and human behaviors associated with the energy, transportation and related sectors. He will, most likely, from time to time update the Clean Hydrogen Ladder based on emerging information or changes in his views. Neither Michael Liebreich nor Liebreich Associates guarantees to update the ladder, nor do we guarantee its accuracy or completeness, and nothing in this document shall be construed to be a representation of such a guarantee.

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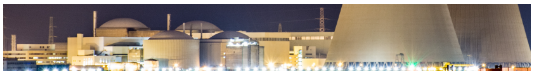
NET-ZERO AMERICA:

Potential Pathways, Infrastructure, and Impacts

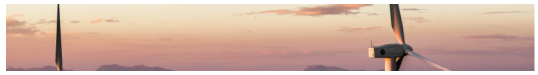
The Net-Zero America research quantifies five distinct technological pathways, all using technologies known today, by which the United States could decarbonize its entire economy. With multiple plausible and affordable pathways available, the societal conversation can now turn from “if” to “how” and focus on the choices the nation and its myriad stakeholders wish to make to shape the energy transition.

This website presents the pathways in an interactive context to enable policy makers and other stakeholders to extract specific results that are most useful to them. The site should be used in conjunction with the Net-Zero America report to fully understand the data contained herein.

Five Approaches to Decarbonization:



Scenario 1



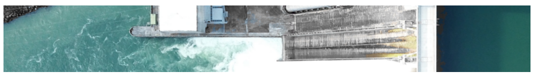
Scenario 2

Scenario 3

- Nearly full electrification of transport and buildings by 2050
- No land-use change for biomass supply allowed
- Few other constraints on energy supply options

- Less-rapid electrification of transport and buildings
- No land-use change for biomass supply allowed
- Few other constraints on energy supply options

- Less-rapid electrification of transport an
- Biomass supply requires converting som land from food to energy crops
- Few other constraints on energy supply



Scenario 4

E+ RE-
Renewable Constrained

- Nearly full electrification of transport and buildings by 2050
- Solar and wind power annual capacity additions constrained to historical maximum
- No land-use change for biomass supply allowed
- Few other constraints on energy supply options

Scenario 5

E+ RE+
100% Renewable

- Nearly full electrification of transport and buildings by 2050
- No fossil fuel use allowed by 2050
- No land-use change for biomass supply allowed
- No new nuclear power construction allowed, existing plants retired
- No underground storage of CO2 allowed

Scenario 6

REF
Reference

- Based on US EIA, *Annual Energy Outlook 2* case, no new policies)
- No greenhouse gas emission constraints
- Same (low) projected oil and gas prices a pathways

Explore the Data

Read our data guide (PDF)

Examine by

YEAR PATHWAY

Scope (select state or national)

Michigan

Filter

REF E+ E- E-B+ E+RE- E+R

Categories & Subcategories	2020	2025	2030	2035	2040	2045
PILLAR 1: EFFICIENCY/ELECTRIFICATION						
OVERVIEW						
2.15.68 Final energy use - Transportation (PJ)	809	757	687	629	583	530
2.15.69 Final energy use - Residential (PJ)	562	525	498	472	439	392
2.15.70 Final energy use - Commercial (PJ)	316	311	304	297	288	275
2.15.71 Final energy use - Industry (PJ)	501	510	521	522	536	546
2.15.72 Final energy use - Electricity (PJ)	390	389	401	422	468	539
2.15.73 Final energy use - Hydrogen (PJ)	1.91	2.46	4.78	12.7	24.8	38.9
2.15.74 Final energy use - Steam (PJ)	155	153	159	159	165	171
2.15.75 Final energy use - Pipeline gas (PJ)	632	597	560	518	461	378
2.15.76 Final energy use - Pipeline gas feedstock (PJ)	0.407	0.465	0.494	0.494	0.523	0.552
2.15.77 Final energy use - Gasoline (PJ)	584	533	468	406	347	272
2.15.78 Final energy use - Distillate oil (PJ)	224	217	202	187	165	134
2.15.79 Final energy use - Jet fuel (PJ)	51.7	51.1	50.7	49.8	48.6	47.1

< 1 2 3 4 5 ••• 21 >

Download this table as a CSV

Download the data sheet for Michigan

Download all NZA data as a CSV (217 MB)

The Future of Gas Utilities Series

TRANSITIONING GAS UTILITIES TO A DECARBONIZED FUTURE

Part 1 of 3

AUGUST 2021

Brattle

FUTURE OF GAS UTILITIES

Agenda

SERIES INTRODUCTION

Energy Sector's Changing Landscape Threatens Natural Gas Utilities

Natural gas utilities face **increased risk** related to decarbonizing the energy sector.

- Pressure is increasing to ban new gas uses and gradually "electrify everything."
- However, as a countervailing force, a growing number of states have prohibited the enactment of bans on new gas connections.
- Regardless of bans, cost declines related to innovation, as well as federal, state, and municipal support policy, will increase electrification (as is happening with renewable adoption in the electricity sector).

At the same time, there are **approximately $150–180 billion of unrecovered gas distribution infrastructure.**

Utilities will need to consider how to **recover their costs from a shrinking customer base**, which could lead to higher rates and create a vicious cycle.

Sources: S&P Market Intelligence; American Gas Association; EIA 2015 Residential Energy Consumption Survey.

SERIES INTRODUCTION

Impact Will Differ for Pure-Play, Combination, and Electric Utilities

The natural gas transition will impact all three types of utilities:

- **Combination utilities** may be better positioned to transition business from gas to electricity investment and sales. Gas sale declines presents downside risk, but electrification can present upside potential.
- Electrification serves as a boon to **electric utilities**, which can increase electricity investments and sales.
- **Pure-play gas utilities** face the most downside risk, and will need to be innovative and proactive to grow business.

Regulation will fundamentally answer the question of "who pays" for the transition, highlighting the need for well-designed regulatory strategy.

Who pays?

- Gas, electric, or combination utilities
- Shareholders or utility customers
- Gas or electric customers
- Current or future customers
- Advantaged vs. vulnerable populations

This series provides commentary on these issues and aims to help gas and combination utilities navigate the transition in a fiscally and socially responsible way.

SERIES INTRODUCTION

Waiting Passively Is Not a Sustainable Option for Utilities or Customers

If gas utilities defer building a long-term strategy, they risk not having a voice in the policy, planning, and regulation process.

Gas demand reduction and bill increases for remaining customers will come with or without utility involvement. However, the needed change is likely to be delayed or inefficient without utility involvement.

The scale of the transition is massive: displacing natural gas in the US would involve replacing nearly 150 million heating and cooking appliances, in addition to the gas distribution system infrastructure.

Proactive implementation of suitable solutions affords utilities the following benefits:

- Allows utilities to build a diversified and tailored strategy ahead of regulatory mandates
- Finding substitute capital deployments makes gas utilities part of the solution, not an obstacle
- Satisfy customers, reduce costs, and head off or offset probable customer defection
- Address investor concerns

The transition process will play out over many years, **but the planning must start now**.

SERIES INTRODUCTION

The Transition Presents Significant Growth Opportunities

Natural gas utilities can create new business opportunities as an enabler of the energy transition, through proactive and innovative approaches.

- Utilities' access to capital, capabilities in large-scale planning and execution, and experience in working with regulatory authorities make them uniquely positioned to help plan and implement large infrastructure transitions.
- Clean fuels, such as renewable natural gas (RNG) and hydrogen, can provide growth opportunities while re-utilizing gas utilities' existing infrastructure or right-of-ways.

Gas utilities have options to create and capture value and reduce customer costs.

- Utilities' pathways will depend on their characteristics (pure-play versus combination), location, customer base, and regulatory environment.

Natural gas utilities will need to work closely with legislators, regulators, and stakeholders to **design and pursue enabling regulatory mechanisms and policies** to navigate this transition.

SERIES INTRODUCTION

Building Blocks for a Successful Energy Transition

1

Is it a real risk? How big is it, and how immediate?

- Policy risk
- Business strategy risks
- Cost of capital implications

2

What strategies will enable solutions?

- Regulatory framework for transition
- New technologies and infrastructure
- Securing life of existing assets

3

What steps can be taken to get there?

- Performance-based regulation
- Multi-year rate plan
- New programs

SERIES INTRODUCTION

The Brattle Group’s Future of Gas Utilities Presentation Series

The Brattle Group’s Future of Gas Utilities building blocks will be presented in a series of three presentations to be released in the summer and fall of 2021.

The Brattle Group’s Future of Gas Utilities Series will culminate in a **Symposium**, where industry and Brattle experts will convene to debate key challenges and opportunities facing the gas industry.

The remainder of this slide deck will cover the first building block: **Assessing Risk**.

Part 1: Assessing Risk

The Future of Gas Utilities Series

ASSESSING RISK

Risks and Opportunities of the Transition

Traditional gas utility business models face increasing risks as more states and locales challenge the long-run role natural gas could play in meeting climate and energy policy goals.

- Even though certain states are moving against this trend and enacting prohibitions on bans on new gas connections, cost declines related to technology innovation and federal, state, and municipal policy support will increase the deployment of lower-carbon alternatives to natural gas, as happened with renewables in the electricity sector.
- The transition is already underway: at the current rate, the number of homes with electric space heating could exceed the number of homes with gas space heating by 2032.

The transition will affect **gas companies' growth opportunities, cost recovery, and capital attraction.**

- In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability.
- Utilities will need to recover their costs from a changing – and possibly shrinking – customer base.
- With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks.
- Heightened perceptions of business risk are increasing financing costs for gas utilities. In early 2021, gas utilities traded at a ~20% discount relative to electric utilities.

Any strategic plan (including electrification and alternative gas technologies) must address equity and energy justice by considering financial, health, and economic impacts to vulnerable communities.

ASSESSING RISK

The Debate on the Future of Natural Gas Is Widespread

The **landscape for natural gas has shifted dramatically**, as states and cities across the country have passed natural gas bans and electrification mandates.

States are also launching proceedings on the role gas utilities will play in meeting the state's greenhouse gas (GHG) emissions and clean energy goals.

Proposed approaches include "electrify everything" or leveraging alternative gas technologies such as RNG, hydrogen, etc.

The outcomes being debated vary widely: while some states have banned the use of gas in new buildings, **others have prohibited the enactment of such bans**.

STATES ENACTING GAS BANS | AS OF JULY 21, 2021

	STATE-WIDE	CITY			
	Proceeding on Future Role of Natural Gas	Proposed Gas Bans	Enacted Gas Bans	Implemented Moratoriums	Electrification "Reach" Codes
California	✓		✓		✓
Oregon	✓	✓			
Washington	✓	✓	✓		
New York	✓	✓		✓ PARTIALLY LIFTED	✓
Massachusetts	✓	✓	✓		
Colorado	✓	✓			✓
Washington, DC	✓				
Vermont					✓

Proposed Prohibition on Gas Bans	CO, MI, MN, NC, PA
Enacted Prohibition on Gas Bans	AL, AR, AZ, FL, GA, IA, IN, KS, KY, LA, MO, MS, OH, OK, TN, TX, UT, WV, WY

ASSESSING RISK

Gas Utilities Can Participate in a Decarbonized Future to Mitigate a Potential Death Spiral and Control Customer Costs

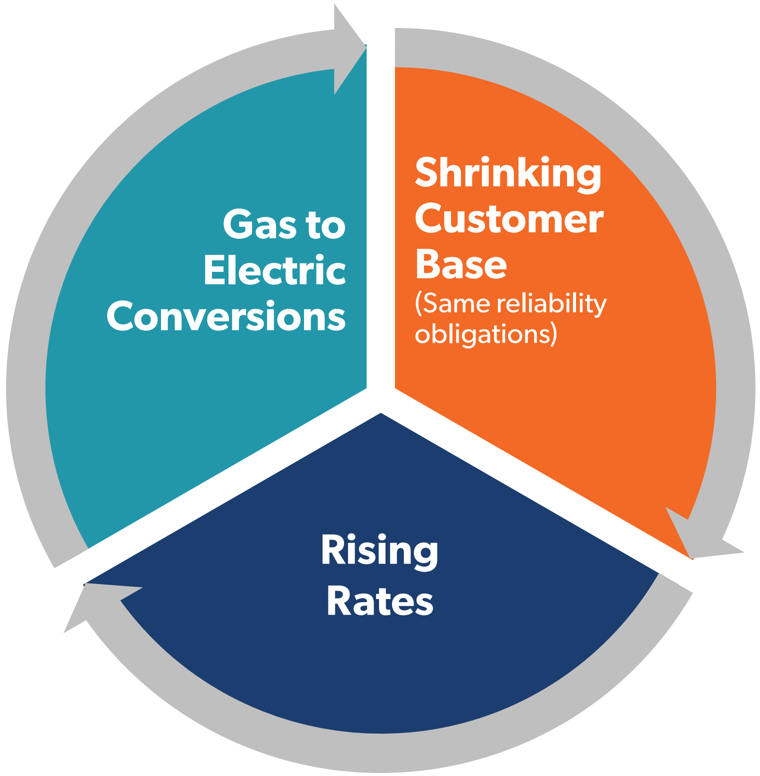
As states pursue degasification policies and homes convert to electric heating, **utilities risk losing customers and load.**

- Nationally, electric heating is outpacing gas heating adoption.
- Technology mandates and policy further accelerate the problem.

Utilities will likely **continue investing in their existing system for safety and reliability but need to recover those costs from a shrinking customer base.**

- This puts remaining customers at risk, a "death spiral" trend pushing more customers to electrification.
- Up to $150–180 billion of gas distribution assets could be under-recovered as a result of the transition.

This spiral will increase customer costs and increase energy burdens, especially for low-income and vulnerable populations.



Gas utilities may reverse this problem if they quickly become part of the solution to a decarbonized future.

ASSESSING RISK

Gas Utilities' Risks and Opportunities with Decarbonization

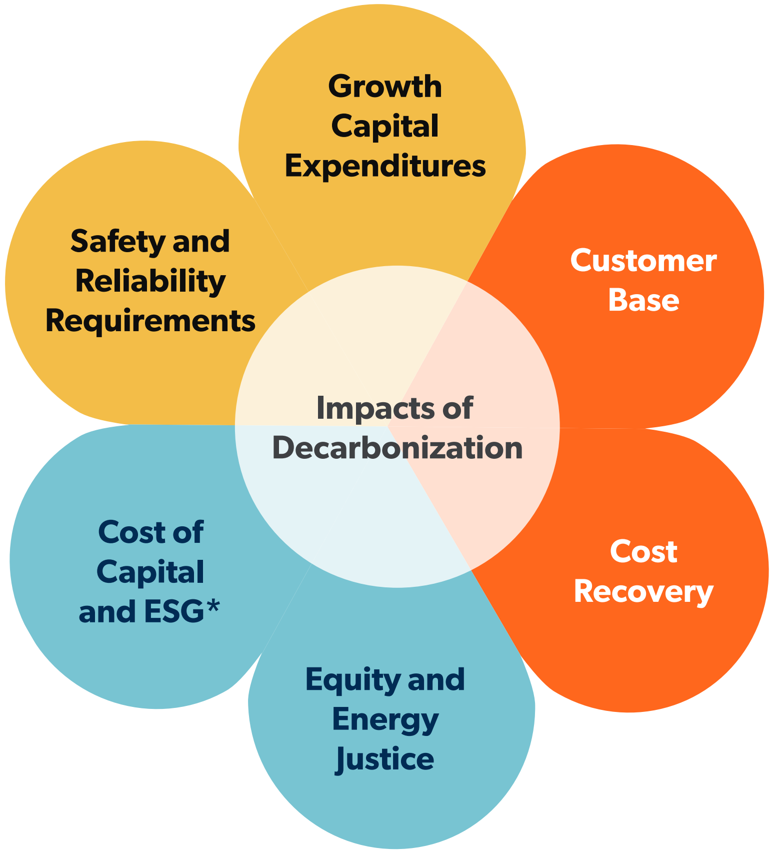
Proposed decarbonization pathways generally emphasize electrification, challenging the traditional business model of natural gas utilities.

Without proactive adjustments, utilities face increasing **cost recovery risks from capital investments** to grow the gas system or to maintain safety and reliability requirements.

There are **offsetting opportunities**, such as:

- Alternative fuels (RNG, hydrogen) are a viable alternative for end-uses that lack cost-effective electrification options.
- Long-run deep degasification may be expensive to achieve, requiring utilities to invest in clean performance of existing assets.
- Utilities could own and rate base gas replacement infrastructure, earning a return on these decarbonization assets.

The transition will take time and depends on factors such as costs, regulatory and legislative mandates, and customer adoption.



*ESG stands for Environmental, Social, Governance investing

ASSESSING RISK

Traditional Planning Faces Conflicting Regulatory and Financial Expectations

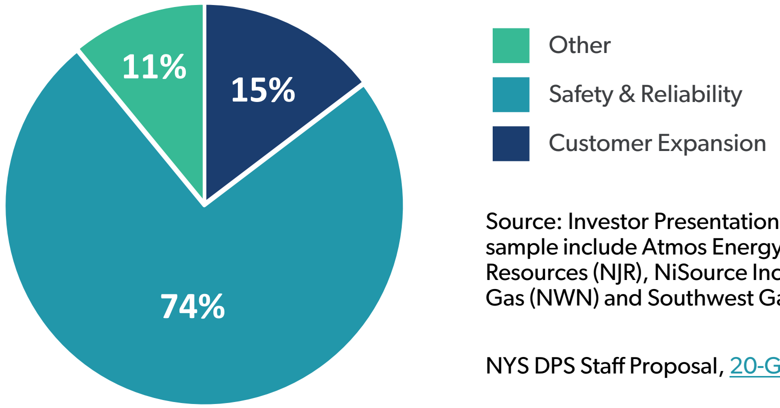
New gas assets placed into service today have a useful life of ~40 years – well beyond target dates for many decarbonization goals, creating cost-recovery risk.

- Gas utility capital expenditures have grown by around double the rate of water and electric utilities' capital expenditures.

Regulators are requiring gas utilities to develop gas long-range capital investment plans that conform to state climate and energy policy goals. Gas utilities and regulators need to decide today how best to deploy capital and avoid cost recovery risks due to the transition.

- **Alternative depreciation schedules** may be required to fully recover traditional gas investments before policy target dates.
- **Diversifying into gas decarbonization technologies** can limit exposure to lost growth opportunities and reduce stranded asset risk.

FORECASTED CAPITAL EXPENDITURES



Source: Investor Presentations, 2020. Utilities in the sample include Atmos Energy (ATO), New Jersey Resources (NJR), NiSource Inc. (NI), Northwest Natural Gas (NWN) and Southwest Gas (SWX).

NYS DPS Staff Proposal, 20-G-0131, February 12, 2021.

NY GAS PLANNING PROCEEDING | STAFF PROPOSAL

Utilities must incorporate demand-side solutions into their long-term planning to **reduce gas demand and the need for gas infrastructure investments.**

LDCs must **identify opportunities to avoid replacing leak prone pipe** and instead deploy "Non-Pipeline Alternative" investments.

ASSESSING RISK

Safety and Reliability Investments Will Remain a Priority

Utilities are under increasing pressure and are making **significant investments to meet new and existing safety and reliability requirements**.

- PHMSA's Mega Rule went into effect in 2020, mandating confirmation of Maximum Allowed Operating Pressures (MAOP), more frequent and regular pipeline integrity assessments, and new repair and leak detection requirements, amongst other requirements.
- This will require material investments, but increases the risk of obsolescence before the end of normal asset life (~40 years).

Utilities are also focused on replacing **leak-prone pipe,** which reduces methane emissions and helps meet state and corporate GHG emission targets.

- 32 natural gas utilities have pledged to reduce methane intensity to 1% by 2025.
- New York is asking utilities to identify opportunities to retire leak prone pipe and instead deploy non-pipeline alternatives, such as electrification of heating.
- Methane is a more potent GHG than CO_2 even though it is short-lived. Its 20-year warming potential is 80x – and its 100-year warming power is 25x – that of CO_2, per ton emitted.

Enabling regulatory mechanisms will need to be designed and implemented to recover safety and reliability costs from a changing and/or declining customer base.

ASSESSING RISK

Shifts in Customer Base Increase Cost Recovery Risks

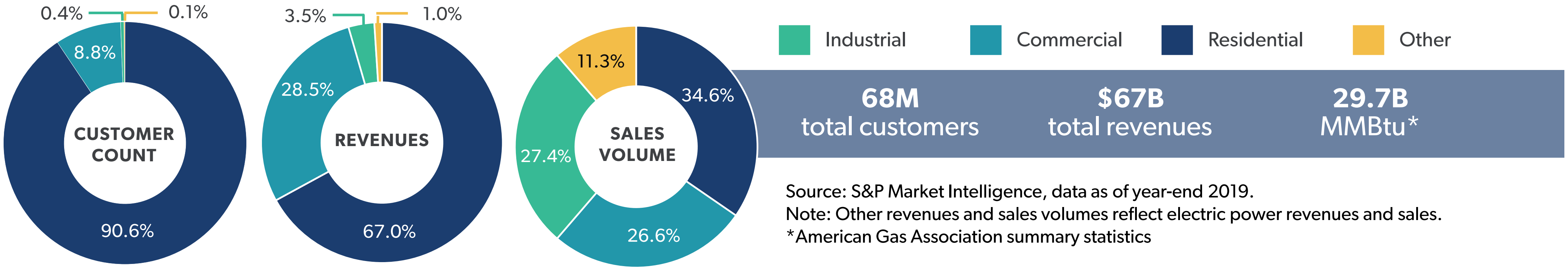
The transition **will not occur at the same pace or magnitude across customer classes**, which compounds cost recovery risks (cost allocation, appropriate tariff designs, equity and energy justice).

- Residential customers, who are more likely to convert to electric alternatives, comprise 90% of total natural gas utility customers and 67% of revenues, but they account for only one-third of total system volumes.
- Harder to electrify industrial customers are a small portion of total customers but about 27% of total sales volumes.
- Differences in customer transition trends will impact the pace and feasibility of achieving state GHG emission targets.

Gas utilities can mitigate this risk by focusing on degasification solutions for commercial and industrial customers, which could most effectively help meet state and corporate decarbonization goals.

Declines in customer base, starting with easy-to-electrify customers, will raise costs for remaining customers, such as for low-income and other vulnerable customer populations.

Gas Utility Customer Base



Source: S&P Market Intelligence, data as of year-end 2019.
Note: Other revenues and sales volumes reflect electric power revenues and sales.
*American Gas Association summary statistics

ASSESSING RISK

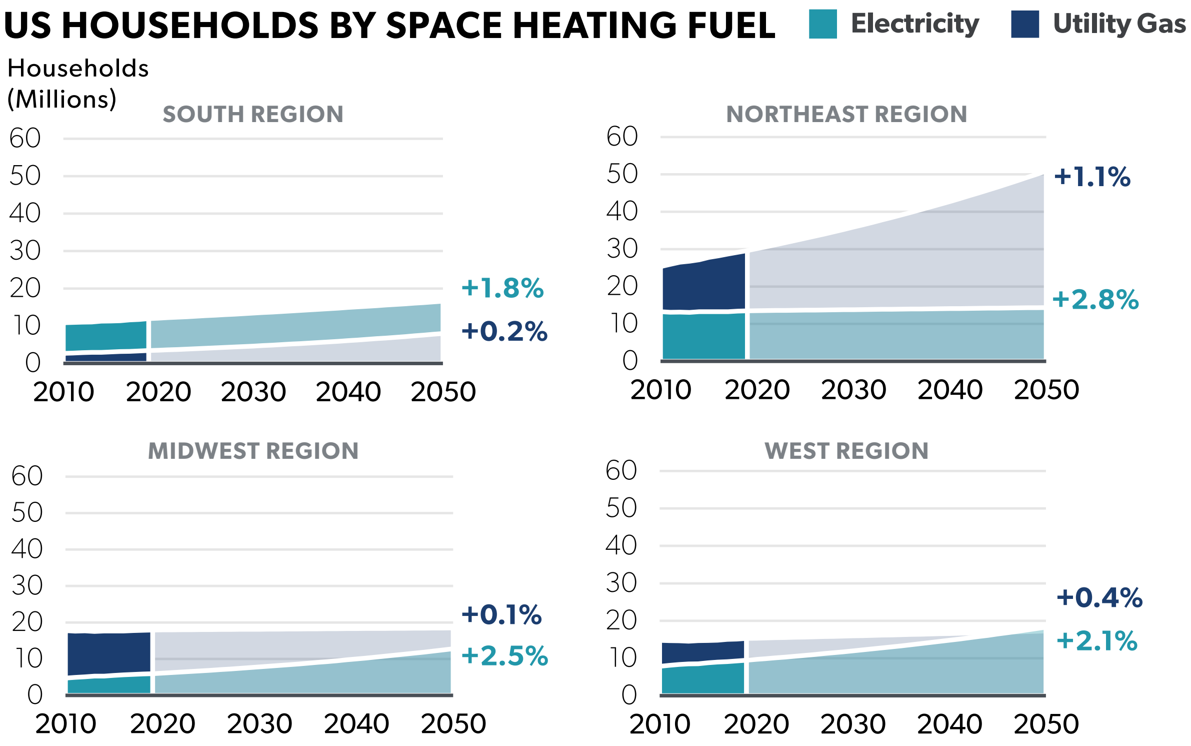
Heating Electrification Will Accelerate Declines in Gas Customer Base

Heating electrification is outpacing gas growth in some parts of the country. At the current pace, the number of homes with electric space heating could surpass homes with gas space heating by 2032.

- Heat pumps remain more expensive than gas furnaces, but could become more competitive with technological improvements and financial incentives.
- Economics of heat pump water heaters (HPWH) can be more appealing because of lower upfront costs relative to heat pumps. HPWH also has a higher efficiency than its gas counterpart.

Electric utilities are promoting rebates for heat pumps and HPWHs to accelerate adoption. As heat pumps and other decarbonization technologies become more popular, **gas utilities need to think strategically about how to participate in this transition in order to remain viable.**

US HOUSEHOLDS BY SPACE HEATING FUEL



Source: US Census Data, 2019. | Note: Electricity includes both heat pumps and electric resistance heating.

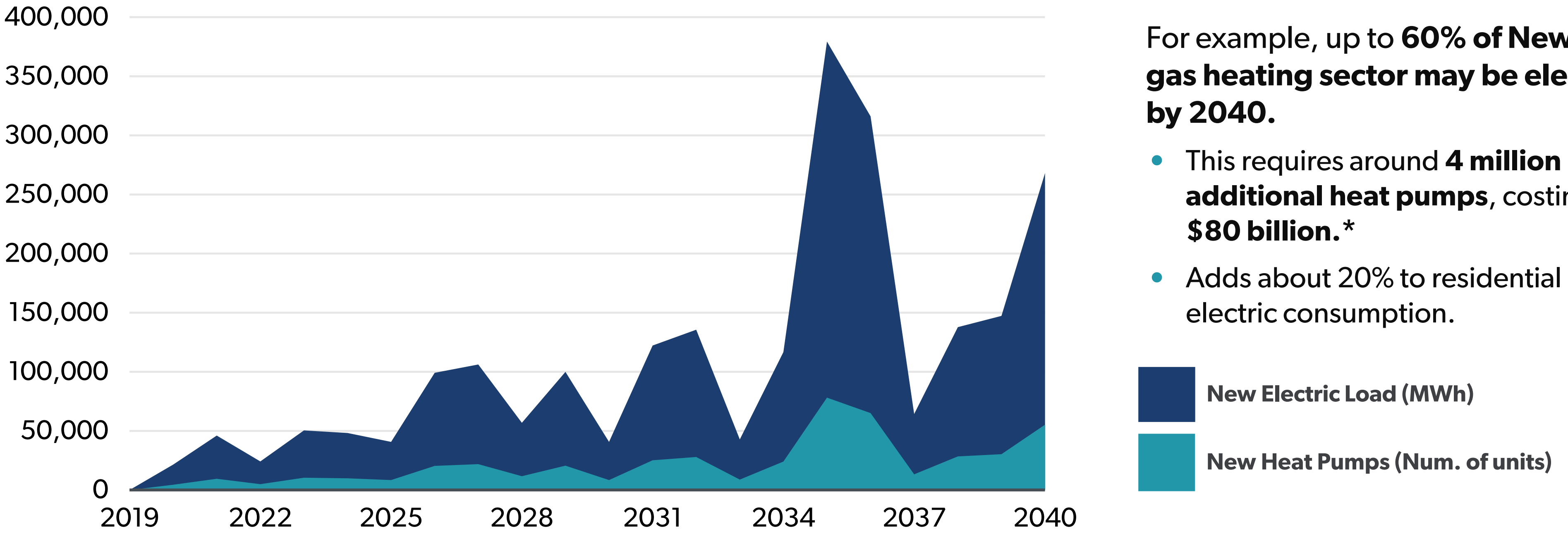
At current rates, homes with electric heating could surpass homes with gas heating by 2032 nationally.

ASSESSING RISK

Death Spiral for Gas Utilities: An Illustrative Example

ELECTRIFICATION OF HEATING SECTOR CASE STUDY: NEW YORK GENERIC UTILITY

Forecasted Newly Electrified Load



Source: CCIS NYISO forecast.
*Assumed forecast of new heat pumps from CCIS forecast, calculated new load and related costs. We assume AHSP at $12,800 and GHSP at $35,700 in real dollars. Capital cost assumptions come from New Efficiency NY Analysis of Residential Heat Pumps.

The impact of increasing electrification will vary based on state and local regulations and decarbonization goals.

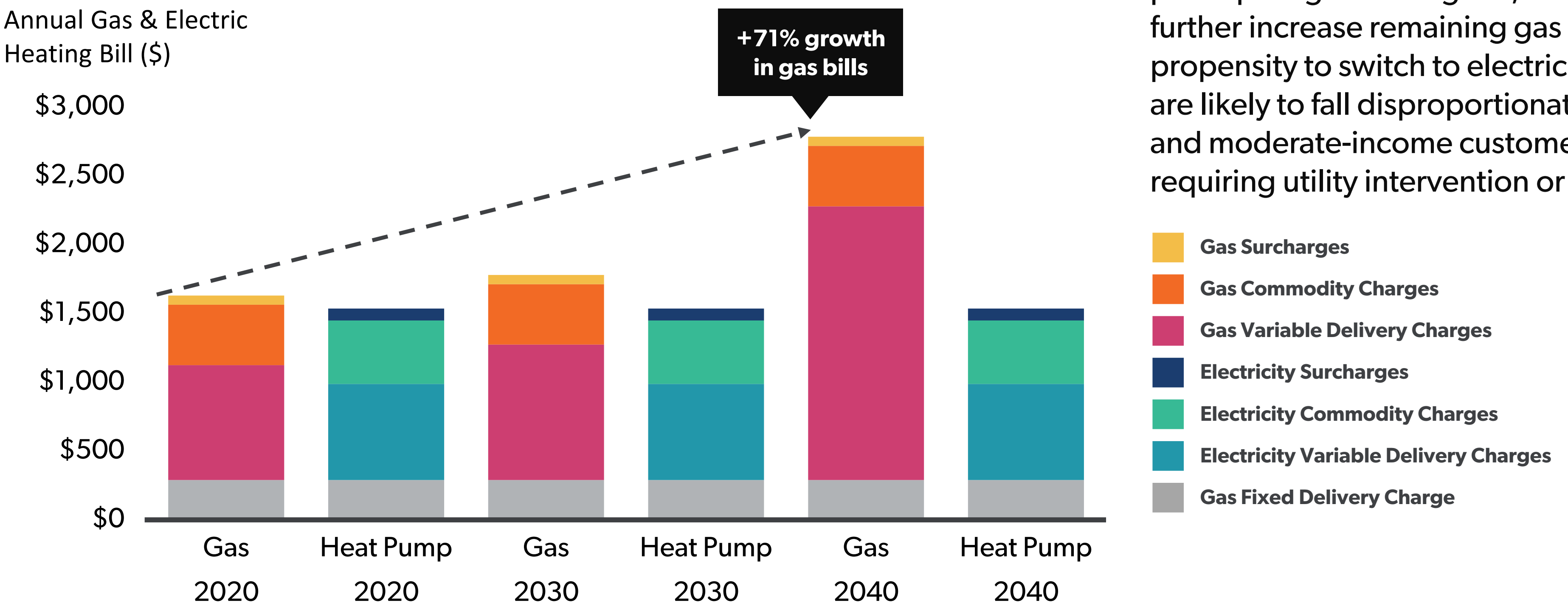
For example, up to **60% of New York's gas heating sector may be electrified by 2040.**

- This requires around **4 million additional heat pumps**, costing about **$80 billion.***
- Adds about 20% to residential electric consumption.

ASSESSING RISK

Death Spiral for Gas Utilities: An Illustrative Example

RATES IMPACT FOR GAS AND ELECTRIC CUSTOMERS
– GAS UTILITY NO-ACTION “DEATH SPIRAL” SCENARIO



There is a large potential for non-participant gas bill to grow, which will further increase remaining gas customer’s propensity to switch to electric. Impacts are likely to fall disproportionately on low- and moderate-income customers, requiring utility intervention or offsets.

Source: CCIS NYISO forecast and The Brattle Group analysis. | Note: Rate impacts for a gas furnace and air source heat pump customer.

ASSESSING RISK

Adverse Investor Reactions to Risks Are Emerging

Investors' **risk perceptions are shifting** as states and locales transition away from natural gas and reduce GHG emissions.

A Berkeley, CA passes the nation's first gas ban (July 2019)

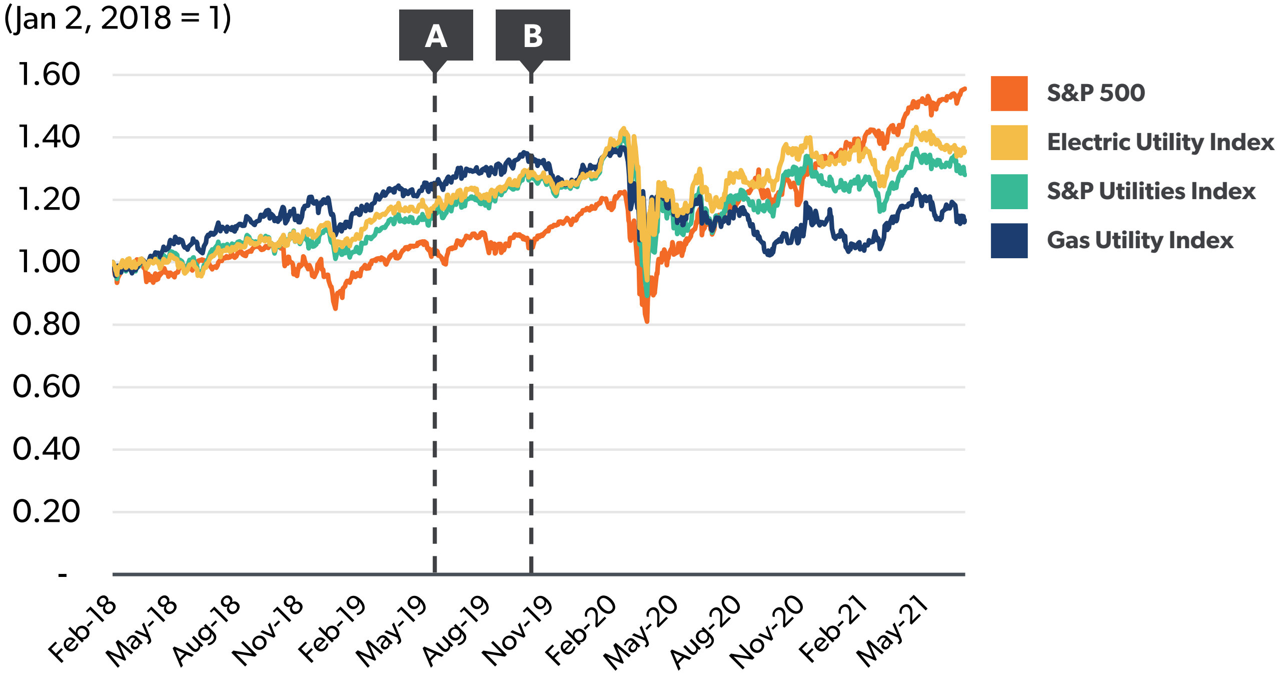
B Brookline, MA passes first East Coast gas ban (Nov 2019)
Five additional CA municipalities have enacted gas bans

All else equal, gas utilities have to **issue more shares to raise the same amount of equity capital**, relative to other utilities.

- Gas utilities currently trade at a ~20% discount relative to electric.
- However, P/E ratios for gas utilities remain elevated at approximately 18 (vs. 19 for electric utilities and 18.5 for S&P util.)

UTILITY STOCK PERFORMANCE

(Jan 2, 2018 = 1)



Notes: **Gas Utility Index includes:** Atmos Energy, Chesapeake Utilities, New Jersey Resources, NiSource, NW Natural, ONE Gas, South Jersey Industries, Southwest Gas, Spire. **Electric Utility Index includes:** AEP, Southern, FirstEnergy, Exelon, Duke, Progress Energy, Evergy, NextEra, Edison International, Dominion. Electric Utility Index is currently trading 3% above S&P Utility Index and 20% above the Gas Utility Index. Data through June 30, 2021.

1: United Nations Environment Programme, Net Zero Banking Alliance.

ASSESSING RISK

Investors Are Becoming Actively Involved in the Debate

Environment, Social, and Governance (ESG) investors are pressuring gas utilities to reduce GHG emissions and eliminate usage of fossil fuels.

43 banks across 23 countries announced a pledge to achieve "net-zero banking," meaning their lending and investment portfolios are on track to reach net zero emissions by 2050.[1]

Utilities are increasingly highlighting RNG, hydrogen, and emission reduction efforts in their investor materials.

70 gas utilities across 31 states have set corporate carbon emission reduction targets.

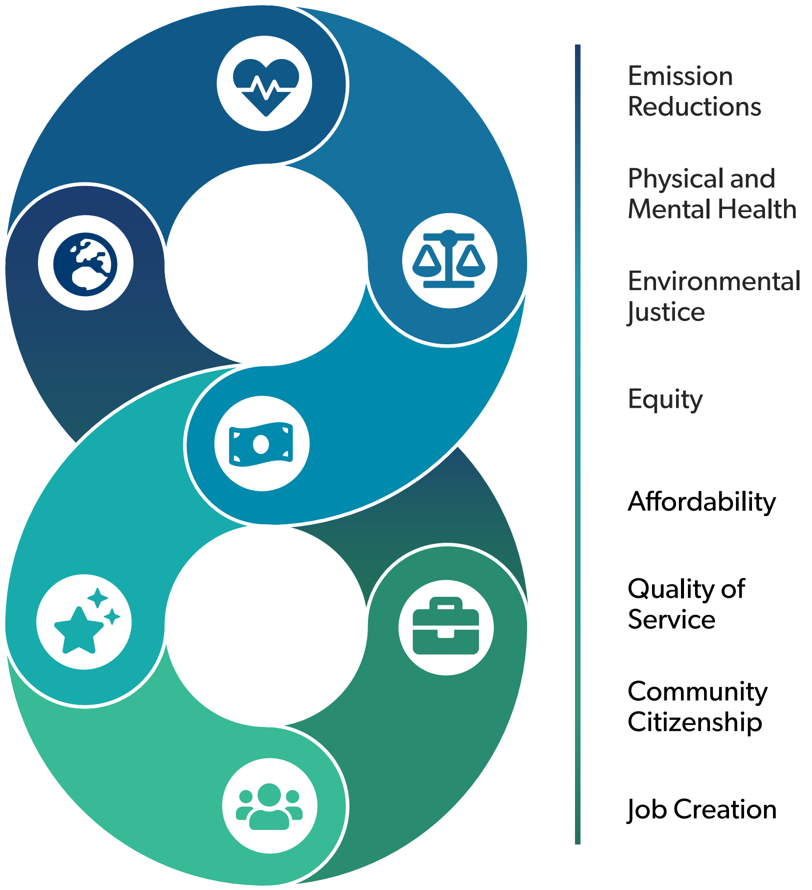
1: United Nations Environment Programme, Net Zero Banking Alliance.

ASSESSING RISK

Equity and Energy Justice Concerns Must Be Considered

Gas utilities and regulators will also need to **consider the risks and impact of the transition on low-income and less advantaged communities**, who may experience rising bills and longer exposure to emissions.

- Public policy is increasingly focused on fairness of service and equitable access to decarbonization technology.
- As more affluent customers adopt electric heating, low-income gas customers could disproportionately experience rate increases and/or be neglected by developers for obtaining new decarbonization technologies.
- For example, adverse effects from electrification on low-income communities can be observed in rooftop adoption, in which low-income communities subsidize delivery costs for homes with rooftop solar receiving net energy metering (NEM).



ASSESSING RISK

Turning Increasing Risk into Opportunity

Gas utilities need to **create an adaptive, long-term business plan that anticipates** the pathways, drivers, accelerators, and decelerators of the transition and identify the type and timing of impacts.

Long-term modeling tools can help

Economy Decarbonization Model: How different might the pace and means of decarbonization be? There are many enabling technologies and policy "knobs" yet to be turned or applied. What are these pathways, and how can they be realized or adjusted? When and how will gas utilities be affected under these different pathways?

Distribution System Planning Model: How can gas distribution investments, operations, pricing, and financing be altered so that utilities not only survive but grow in the face of the transition's long-term effects?

By understanding the possible pathways, utilities can identify their comparative advantages, target market niches, and needed operational and regulatory adjustments.

- A "base case" would look at sales and profits with a passive response to trends in electrification.
- Responsive strategies are then developed for how to influence the path(s) that are likely to occur and how to prepare for their contingencies by selectively avoiding some risks and embracing others.

In Part 2 of this series, we will examine the solution elements available to gas utilities.

How Brattle Can Help

Brattle's Unique Interdisciplinary Experience Provides a Holistic Skillset to Guide Transition

Brattle's Expertise Can Tackle Analysis That Spans All Building Blocks

1
Assess Risk

2
Evaluate Strategies

3
Implement

Assess Transition Risks

Analyze how natural gas bans, electrification mandates, and ESG investment trends will impact business risk and cost of capital.

Estimate revenue loss to electrification under different future scenarios.

Use system dynamics to identify rate risks and customer feedback effects.

Evaluate Strategy and Solutions

Facilitate strategy workshops to establish transition principles, identify potential business strategies, and determine near- and long-term action items.

Identify revenue potential from owning and rate-basing electrification infrastructure and evaluate rate impacts using system dynamics.

Implement Regulatory Changes

Design and calculate tariffs to incentivize transition and protect customer costs.

HOW BRATTLE CAN HELP

DEEP Can Help Utilities Understand Risks and Evaluate Solutions

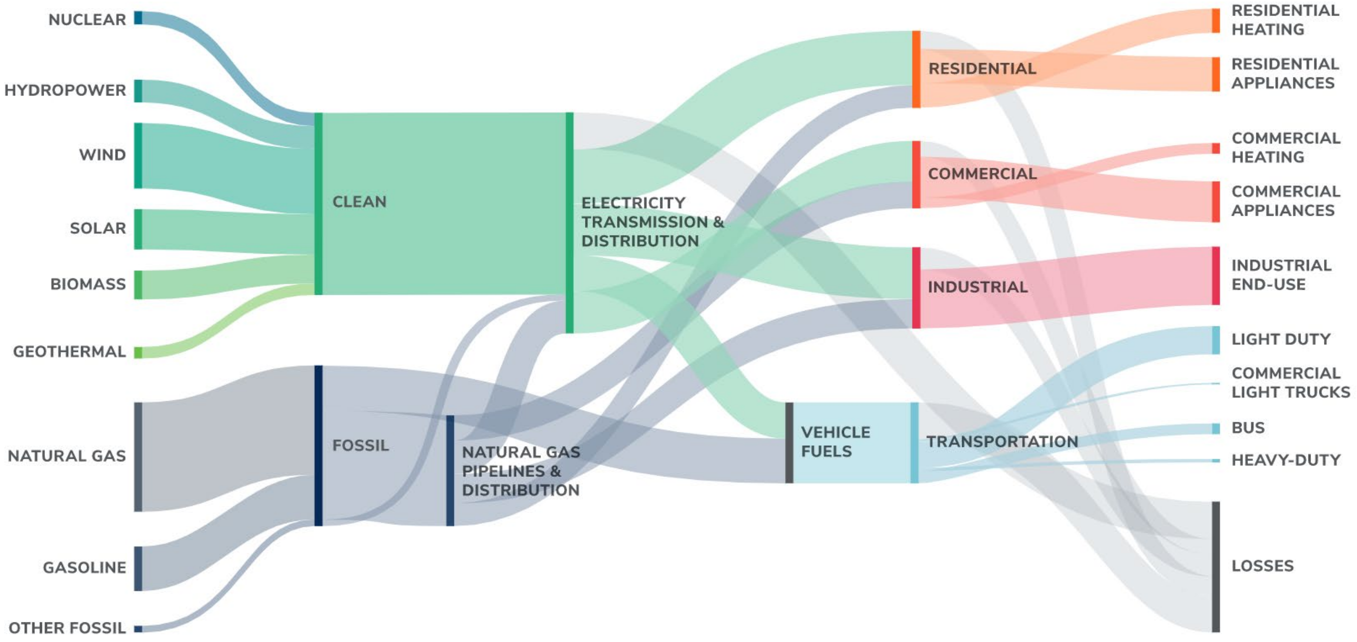
Brattle's **Decarbonization, Electrification & Economic Planning (DEEP) Model** is an energy economy modeling tool that can evaluate:

- The uptake of technologies and impact on gas consumption
- The roles of efficiency, electrification, and fuel-switching
- The utility and customer costs of specific technology pathways

DEEP can evaluate long-term planning impacts and the interactions of:

- Technology adoption
- Decarbonization policies
- Macroeconomic conditions
- Supply and demand

DECARBONIZATION, ELECTRIFICATION & ECONOMIC PLANNING (DEEP) MODEL

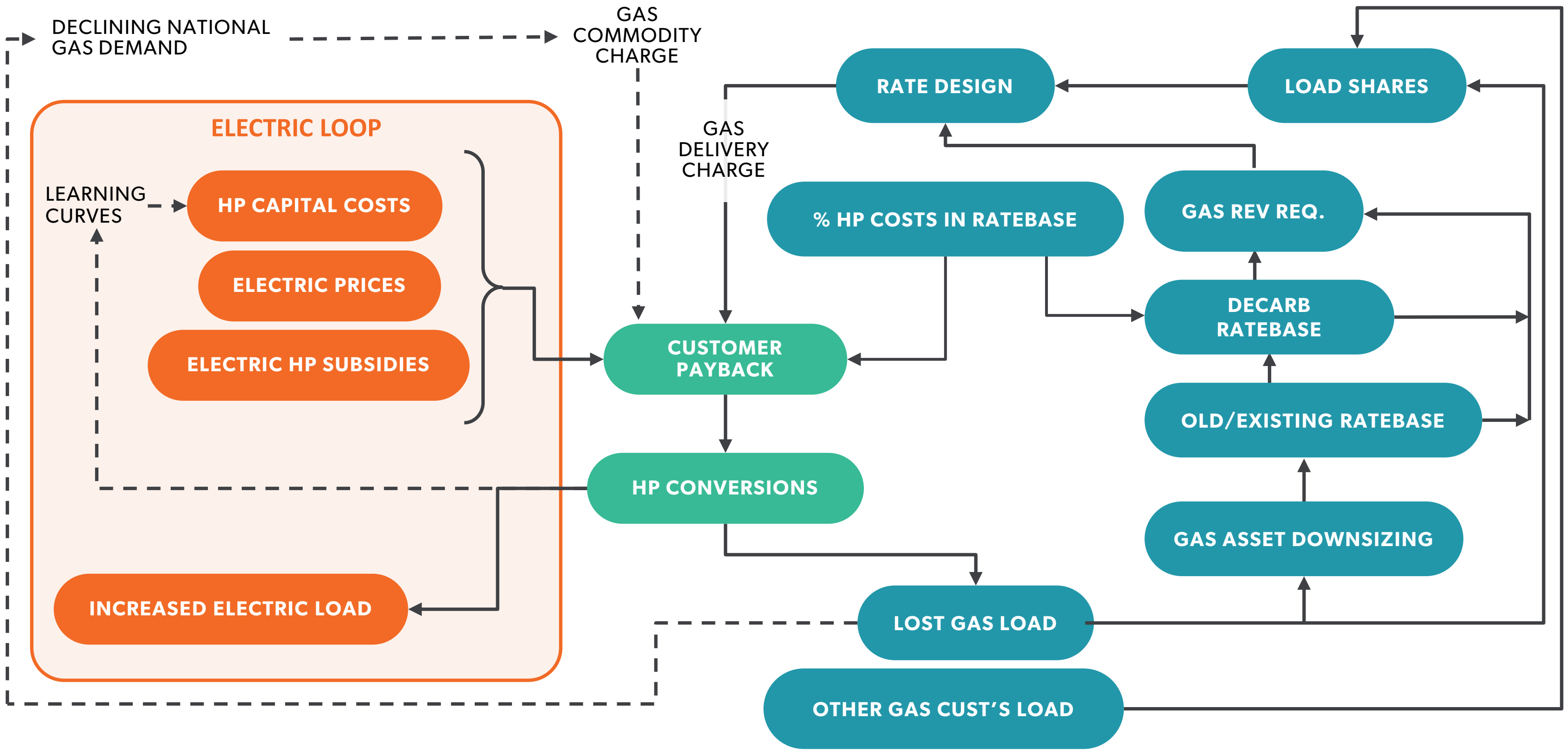


The model can be run in **(1) planning mode** and **(2) optimization mode** to meet client-specific needs.

HOW BRATTLE CAN HELP

Dynamic Modeling Can Help Utilities Understand Risk and Evaluate Potential Strategies

Brattle's technical and analytical abilities can model pathways for decarbonization and the complex interdependencies both within and between the gas and electric sectors, many of which have not yet been thoroughly studied.



Brattle's **System Dynamics Model** can help utilities analyze the complex feedbacks and interdependencies associated with the transition.

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Clarity in the face of complexity

Brattle

Propane cost	$2.51	$/gallon	*DTE Mesick-Buckley Grant proposal*						
electric rate	$0.161	per kWh	*https://www.consumersenergy.com/residential/rates/electric-rates-and-programs/summer-time-of-use-rate*						
monthly gas customer charge	$17.60		*Exhibit A-16, Schedule F3*						
monthly IRM surcharge	$0.80		*Exhibit A-16, Schedule F3*						
gas variable rate	$0.922	$/therm	*Exhibit A-16, Schedule F3, https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/dte-gas-company/notices/rateCard.pdf*						
Mesick-Buckley assumed gas use	960	therms	Heat pump efficiency	2.4	COP				
baseline gas heating efficiency	80%	AFUE	electricity required to meet heat need:	32.0	MMBTU				
heat delivered for energy service	76.8	MMBTU	Equivalent to:	9,379	kWh of electricity				
gas bill:			**electric bill:**			**propane bill:**			
customer charges	$220.80								
variable cost	$884.92		variable cost	$1,509.96		Energy equivalents:	91452	BTU/gallon	
						Energy equivalents:	0.091452	MMBTU/gallon	
annual bill	$1,105.72		annual incremental electric bill	$1,509.96					
annual Mesick-Buckley 10-year charge	$333.12					Propane cost per MMBTU	$27.45	$/MMBTU	
						propane annual bill	$2,634.82		
annual gas bill in M-B	$1,438.84		Gas - Electric difference (M-B):	$71.13					
corrected M-B charge (10-year)	$842.40					Propane-Electric difference:	$1,124.86		
corrected annual gas bill in M-B	$1,948.12		Gas - Electric difference (M-B; 10; corrected):	-$438.15		Propane-Gas difference (M-B; corrected):	$686.71		
corrected M-B charge (20-year)	$752.88								
corrected annual gas bill in M-B	$1,858.60		Gas - Electric difference (M-B; 20; corrected):	-$348.63					

Propane cost	$2.51	$/gallon	*DTE Mesick-Buckley Grant proposal*					
electric rate	$0.161	per kWh	*https://www.consumersenergy.com/residential/rates/electric-rates-and-programs/summer-time-of-use-rate*					
monthly gas customer charge	$17.60		*Exhibit A-16, Schedule F3*					
monthly IRM surcharge	$0.80		*Exhibit A-16, Schedule F3*					
gas variable rate	$0.922	$/therm	*Exhibit A-16, Schedule F3, https://www.dteenergy.com/content/dam/dteenergy/deg/website/common/about-us/company-information/dte-gas-company/notices/rateCard.pdf*					
Peach Ridge assumed gas use	1300	therms	Heat pump efficiency	2.4	COP			
baseline gas heating efficiency	80%	AFUE	electricity required to meet heat need:	43.3	MMBTU			
heat delivered for energy service	104	MMBTU	Equivalent to:	12,700	kWh of electricity			
gas bill:			**electric bill:**			**propane bill:**		
customer charges	$220.80							
variable cost	$1,198.33		variable cost	$2,044.74		Energy equivalents:	91452	BTU/gallon
						Energy equivalents:	0.091452	MMBTU/gallon
annual bill	$1,419.13		annual incremental electric bill	$2,044.74				
Peach Ridge 10-year charge (per year)	$530.88					Propane cost per MMBTU	$27.45	$/MMBTU
						propane annual bill	$3,567.99	
annual gas bill in Peach Ridge (DTE)	$1,950.01		Gas - Electric difference (PR):	$94.74		Propane-Gas difference (PR; DTE):	$1,617.98	
corrected PR charge (10-year)	$1,494.48					Propane-Electric difference:	$1,523.25	
corrected annual gas bill in PR	$2,913.61		Gas - Electric difference (PR; 10; corrected)	-$868.86		Propane-Gas difference (PR; corrected):	$654.38	
corrected M-B charge (20-year)	$1,305.84							
corrected annual gas bill in M-B	$2,724.97		Gas - Electric difference (PR; 20; corrected)	-$680.22		Propane-Gas difference (PR; corrected):	$843.02	

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-80-B December 6, 2023

Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals.

ORDER ON REGULATORY PRINCIPLES AND FRAMEWORK

TABLE OF CONTENTS

SUMMARY

The Department of Public Utilities ("Department") announces a regulatory framework intended to set forth its role and that of the Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its target of net-zero greenhouse gas ("GHG") emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020). The Department seeks to enable the Commonwealth to move into its clean energy future while simultaneously safeguarding ratepayer interests and maintaining affordability for customers; ensuring safe, reliable, and cost-effective natural gas service; minimizing the burden on low- and moderate-income households as the transition proceeds; and facilitating a just workforce and energy infrastructure transition.

In this proceeding, the Department reviewed eight potential decarbonization "pathways" to achieving the target of a 90 percent gross reduction in GHG emissions by 2050 as compared to 1990 levels, as well as interim GHG emissions reductions targets of 50 percent by 2030 and 75 percent by 2040. The decarbonization pathways are designed to reflect different futures for the LDCs and their customers, ranging from ongoing use of the LDCs' distribution networks to 100-percent decommissioning of gas distribution infrastructure in the Commonwealth. The Department makes no findings as to a preferred pathway or technology; rather, our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy objectives.

The Department considered six regulatory design recommendations intended to facilitate the Commonwealth's transition: (1) support customer adoption of and conversion to electrified and decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department makes specific findings about each of these regulatory design recommendations as detailed in the Order.

As to supporting customer adoption of and conversion to electrified and decarbonized heating technologies, the Department finds that to achieve the Commonwealth's climate targets, there must be a significant increase in the use of electrified and decarbonized heating technologies. The Department and LDCs can play a pivotal role by enhancing incentives and expanding the Mass Save energy efficiency programs to facilitate customer use of heat pumps. The Department also addresses the critical need to minimize costs for customers, including through pursuit of outside funding sources, and prioritizing workforce development to enable a just transition framework for gas industry workers as well as customers.

The Department rejects the recommendation to change its current gas supply procurement policy to support the addition of renewable natural gas ("RNG") to LDC supply portfolios due to concerns regarding the costs and availability of RNG as well as its uncertain

status as zero-emissions fuel. The Department does support the option for customers to be able to purchase RNG from their LDC or a supplier at full cost to the customer.

Given the critical importance of significantly decarbonizing the heating sector, the Department considered the proposal that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen. As detailed in the Order, the Department views networked geothermal projects as those with the most potential to reduce GHG emissions, and expresses support for targeted electrification as well.

The Department seeks to dissuade gas customer expansion and to align rate design with the Commonwealth's climate objectives. To achieve this, the Department instructs gas utilities to revise their per-customer revenue decoupling mechanism to a decoupling approach based on total revenues. Removing the incentive to add new customers aligns the LDCs' rate design with climate objectives and GHG emissions reductions targets. The Department finds it must examine the issue of depreciation, i.e., the period of time over which a capital investment is recovered, and stranded assets. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments, and to identify the impacts of accelerated depreciation proposals, as well as potential alternatives to accelerated depreciation.

The Department finds that consideration of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation, is necessary to minimize investments in the gas pipeline system that may be stranded costs in the future as decarbonization measures are implemented. Going forward, the Department states that as part of future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery.

The Department agrees with suggestions that the standards for investments to serve new customers be examined. The Department therefore directs the LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions. Further, in reviewing future applications for new service, the Department will examine the appropriateness of the existing standard—that there be no adverse impacts on existing natural gas customers—in the context of a broader climate mandate.

The Department observes that there are numerous concerns regarding affordability for customers, including the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity, and also higher rates for customers who remain on the system. Cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers from environmental justice populations, present equity challenges as well.

Finally, the Department finds that the clean energy transition will require coordinated planning between LDCs and electric distribution companies, monitoring progress through LDC reporting, and aligning existing Department practices with climate targets. To that end, the Department orders LDCs to submit individual Climate Compliance Plans to the Department every five years beginning in 2025, and to propose climate compliance performance metrics in their upcoming performance-based regulation filings, ensuring a proactive approach to achieving climate targets.

I. INTRODUCTION

The Department of Public Utilities ("Department") opened this inquiry on October 29, 2020, to examine the role of Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its 2050 climate targets, and to identify strategies for enabling the Commonwealth to move into its net zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80, Vote and Order Opening Investigation at 1 (2020) ("Vote and Order"). The Department specifically sought to develop a regulatory and policy framework to guide the evolution of the gas distribution industry in the context of a clean energy transition that requires the Department to consider new policies and structures to protect ratepayers as the Commonwealth reduces its reliance on natural gas. D.P.U. 20-80, at 4. This proceeding is necessarily one step—not the first and certainly not the last—as we endeavor to chart a path forward that enables the Commonwealth to achieve its target of net zero GHG emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020), available at https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download (last visited November 29, 2023). The Department docketed this matter as D.P.U. 20-80.

Through this investigation, the Department has gathered a significant body of information from the LDCs and a wide range of institutional and individual stakeholders, evincing the need for an evolving, multifaceted, broadly coalitional, and responsive process as we seek to define and meet the significant challenges and potential opportunities that are presented not only by the Commonwealth's climate targets, but also by the threat and reality of the climate crisis itself. The Department acknowledges and appreciates the time, commitment, and thoughtful contributions provided by many stakeholders throughout this proceeding. In this Order, we first enunciate a set of regulatory principles that will guide our decision-making in this and future dockets. We then address in more detail the reports and analyses produced by the LDCs and their consultants, as well the comments and analyses submitted by stakeholders. Our purpose here never has been to dictate one path forward, but to gather information and identify existing and potential means within our authority to remove barriers to the clean energy transition and find ways for the Department to facilitate and accelerate pursuit of our 2050 climate targets. To that end, in this Order we identify future areas of inquiry that will be explored and note those future proceedings (including technical conferences, adjudications, and additional investigations) where we will investigate and implement the issues and principles identified herein.

In enunciating regulatory principles, our intent is that these foundational propositions will inform many of the Department's processes and proceedings through a "whole of DPU" approach, not limited to those matters such as this where climate and GHG-reduction policies explicitly are at issue, but also inform rate design and other more traditional Department functions within our authority. We also note areas in which the Department cannot (or cannot yet) act unilaterally, observing where legislative change or other agency action is required as we seek to pursue vigorously our role in a "whole of government" response to the climate crisis. The Department is one governmental actor working toward the clean energy transition, and we anticipate necessary future legislative action, as well as implementation from the Executive Office of Energy and Environmental Affairs ("EEA"), Massachusetts Department of Energy Resources ("DOER"), Massachusetts Department of Environmental Protection ("MassDEP"), and the Massachusetts Clean Energy Center ("MassCEC"), among others. Finally, in establishing these guiding principles we take care to emphasize the role of communities, neighborhoods, and individuals within the clean energy transition, as we seek to facilitate active participation in a "whole of society" approach to electrification, decarbonization, a just and equitable workforce transition, and equitable investment in communities in pursuit of our 2050 climate targets. While the Department cannot dictate the choices of individual consumers, we can and will seek to maintain a safe, reliable, and affordable system while encouraging and facilitating the thousands of small transitions that must occur on household, neighborhood, and community levels for the Commonwealth as a whole to move into its clean energy future.

II. PROCEDURAL HISTORY

On October 29, 2020, the Department voted to open an investigation into potential policies that will enable the Commonwealth to reach its target of net zero GHG emissions by

2050 and the role of Massachusetts gas LDCs[1] in achieving that goal.[2] D.P.U. 20-80, at 1. The Department stated its intent to solicit utility and stakeholder input in this investigation, noting that EEA was (1) developing in consultation with MassDEP and DOER an evaluation of potential pathways to achieving the Commonwealth's 2050 GWSA statewide net zero emissions limit; and (2) preparing a Clean Energy and Climate Plan ("CECP")[3] for 2030. D.P.U. 20-80, at 3, citing Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); G.L. c. 21N, §§ 3, 4; Massachusetts 2050 Decarbonization Roadmap (December 2020), available at

1 The gas LDCs subject to the Department's jurisdiction are: The Berkshire Gas Company ("Berkshire Gas"); Boston Gas Company d/b/a National Grid ("National Grid (gas)"); Eversource Gas Company of Massachusetts ("EGMA") and NSTAR Gas Company ("NSTAR Gas"), each d/b/a Eversource Energy (together, "Eversource"); Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"); and Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty ("Liberty").

2 Prior to the Department's issuance of the Order, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a petition ("Petition") requesting that the Department open an investigation to assess the future of the LDCs' operations and planning in light of the Commonwealth's target of net zero GHG emissions by 2050 (Attorney General Petition at 1 (June 4, 2020), citing GWSA; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); State of the State Address (January 21, 2020)). The Attorney General's request has been incorporated into this docket.

3 EEA prepares a CECP every five years, beginning in 2010. The CECP sets forth a policy/roadmap for the Commonwealth to meet the GHG emissions limits by 2050. The Interim 2030 CECP developed by EEA was released in December 2020. The final CECP for 2025 and 2030 was released in June 2022 ("2025/2030 CECP") and can be found at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download (last visited November 29, 2023). The Department stated its anticipation that the 2050 Decarbonization Roadmap ("2050 Roadmap") and 2030 CECP (together, the "Roadmaps") would set forth policies affecting ratepayers, LDCs, and the gas industry as a whole. D.P.U. 20-80, at 3. The Department therefore directed the LDCs to: (1) initiate a joint request for proposals ("RFP") for an independent consultant to conduct a detailed study of each LDC and analyze the feasibility of all pathways identified in the Roadmaps, as well as any additional strategies identified by the independent consultant, to help the Commonwealth achieve its goal of net zero GHG emissions by 2050; (2) submit a report prepared by the independent consultant that integrates the individual analyses of each LDC into one, collective report containing comparisons among the LDCs; and (3) submit individual proposals to the Department that includes each LDC's recommendations and plans for helping the Commonwealth achieve its 2050 climate targets, supported by the independent consultant's report, along with all analyses and supporting data. The Vote and Order further directed that the LDCs engage in a stakeholder process to solicit feedback and advice on the independent consultant's report and the LDCs' individual proposals prior to submitting these documents to the Department. D.P.U. 20-80, at 4-5.

On November 6, 2020, the Attorney General filed a motion requesting clarification ("Motion for Clarification") of the Department's Vote and Order with respect to its directives for stakeholder participation in (1) the development of the RFP to hire an independent consultant; and (2) the Massachusetts gas LDCs' development of the report and proposals

(Attorney General Motion for Clarification at 1). The Department received several responses to the Attorney General's Motion for Clarification from interested stakeholders.[4] On February 10, 2021, the Department issued an order on the Attorney General's request. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80-A (2021).

On March 1, 2021, the Attorney General filed a notice of retention of experts and consultants in this investigation at funding not to exceed $150,000, filed pursuant to G.L. c. 12, § 11E(b) ("Notice of Retention"). On May 21, 2021, the Attorney General filed a revised notice to retain experts and consultants seeking an amended funding at an amount not to exceed $350,000 ("Revised Notice of Retention"). The Department received no comments on the Attorney General's Notice of Retention or Revised Notice of Retention[5] and on June 29, 2021, the Department issued an order approving the Attorney General's Revised

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4 The following stakeholders submitted responses to the Attorney General's Motion for Clarification: Conservation Law Foundation ("CLF"); the Sierra Club; Environmental Defense Fund ("EDF"); joint response by the gas LDCs; the Town of Hopkinton; the Gas Leaks Allies; and Mothers Out Front.

5 Pursuant to G.L. c. 12, § 11E(b), the Department must allow all full parties to a proceeding the opportunity to comment on the Attorney General's Notice of Retention. The only full party to this proceeding is the Attorney General. Nevertheless, the Attorney General served her Notice of Retention on the LDCs and the LDCs did not comment. It is unclear whether the Attorney General served her Revised Notice of Retention on the LDCs, but it was not required.

Notice of Retention. D.P.U. 20-80, Order on Attorney General's Revised Notice of Retention of Experts and Consultants (June 29, 2021).

On March 1, 2021, and September 1, 2021, and in accordance with the Department's directives, the LDCs provided status updates regarding the progress with respect to the RFP and stated that, through the RFP, the LDCs selected Energy & Environmental Economics ("E3"), with ScottMadden as subcontractor (together, "Consultants"), to be the independent consultant for the pathways analysis, and the retention of Environmental Resources Management ("ERM") to develop and facilitate the stakeholder process.

On March 18, 2022, pursuant to the Department's Vote and Order, each LDC submitted: (1) the company's individual proposals and plans for helping the Commonwealth achieve its 2050 climate targets within reports entitled "net zero enablement plan[s]" ("Net Zero Enablement Plan," or collectively, "Net Zero Enablement Plans"); and (2) a report on the technical analysis of decarbonization pathways ("Pathways Report") as well as a report on considerations and alternatives for regulatory designs to support transition plans ("Regulatory Designs Report") (collectively, the "Reports").[6] In addition, on this same date the LDCs submitted: (1) a stakeholder engagement report ("Stakeholder Engagement Report") prepared by ERM to develop and facilitate the stakeholder engagement process; (2) the gas LDCs' common regulatory framework and overview of the Net Zero Enablement

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6 The Reports were prepared by the LDCs' Consultants.

Plans ("Framework and Overview"); and (3) a proposed Net Zero Enablement Plan model tariff ("Model Tariff").

On March 23, 2022, the Department issued a Notice of Filing, Public Hearing, and Request for Comments ("Notice") along with an Order of Notice ("Order of Notice").[7] The

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7 On February 14, 2022, the Attorney General and DOER submitted correspondence outlining procedural recommendations, including a proposed procedural schedule for this matter, for which CLF, National Consumer Law Center ("NCLC"), Low-Income Energy Affordability Network ("LEAN"), and Home Energy Efficiency Team ("HEET") expressed support. In consideration of the recommendations submitted by the Attorney General and DOER, the Department set a procedural schedule in this matter on March 24, 2022.

On March 28, 2022, CLF, Acadia Center, EDF, HEET, and Sierra Club jointly filed a motion for reconsideration of the Department's Order of Notice issued on March 23, 2022 ("Joint Motion for Reconsideration"). The Joint Motion for Reconsideration requested that the Department: (1) rescind its March 23, 2022 Order of Notice; (2) extend the procedural schedule set forth by the Department on March 24, 2022; and (3) allow for additional process in this docket, including the opportunity to intervene or otherwise obtain party status, participate in discovery, present expert testimony, and to cross-examine witnesses (Joint Motion for Reconsideration at 11-12).

On April 4, 2022, the Department received a jointly filed response by the gas LDCs ("LDCs' Response to Joint Motion for Reconsideration") objecting to the Joint Motion for Reconsideration on the grounds that (1) the Joint Motion for Reconsideration is improper and contradictory to the purposes of this proceeding and (2) the process outlined in the Department's Notice and procedural schedule is consistent with both Department precedent for similar proceedings and the Attorney General's Petition in this matter (LDCs' Response to Joint Motion for Reconsideration at 3-4).

On April 15, 2022, the Department issued a Hearing Officer Memorandum noting that pursuant to the Notice of Filing and Public Hearing issued in this matter, the deadline for submitting written comments was May 6, 2022. The Department encouraged stakeholders to submit comments identifying issues with the consultants' reports and the LDCs' individual proposals and suggestions and recommendations of alternative

Department held technical sessions on the Reports and Net Zero Enablement Plans on March 30, 2022, and April 15, 2022. On May 3, 2022, and May 5, 2022, the Department held public hearings to receive comments on the Reports and Net Zero Enablement Plans.

The Department received more than 230 initial comments from various stakeholders and members of the public ("Initial Comments"). The Department directed the gas LDCs to respond to the Initial Comments, and the LDCs submitted their response on July 29, 2022 ("LDC Joint Comments"). On September 8, 2022, the Department requested all final comments from stakeholders in response to the LDCs' Joint Comments by October 14, 2022 ("Final Comments").[8, 9]

The Department issued seven sets of common information requests to the gas LDCs, one set of information requests each to Berkshire Gas and Unitil, and two sets of information

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proposals, particularly alternative regulatory framework proposals (Hearing Officer Memorandum at 2 (April 15, 2022)). The Department stated that its goal is to develop an overall regulatory framework that will be used to guide statewide and company-specific proposals, so the Department specifically sought alternative proposals that will inform the Department's analysis on the regulatory framework. The Department further stated its intent to schedule additional technical conferences to explore regulatory framework proposals after the May 6, 2022 comment deadline (Hearing Officer Memorandum at 2 (April 15, 2022)).

8 The substance of the Initial Comments, LDC Joint Comments, and Final Comments is discussed further below in Sections V and VI.

9 DOER submitted late-filed Final Stakeholder Comments on October 17, 2022, pursuant to its request to submit its final comments one business day late. The Department herein accepts DOER's late-filed Final Stakeholder Comments.

requests each to Eversource, Liberty, and National Grid (gas). In total, the Department issued 113 information requests to the LDCs.

III. BEYOND GAS: A SUMMARY OF REGULATORY PRINCIPLES

Massachusetts has long been a national leader in adopting state policies to address climate change. Through our actions in this proceeding, we continue in that leadership role by tackling the challenging issues associated with developing a pathway for the transition in the natural gas industry that will be necessary for the Commonwealth to achieve its target of net-zero GHG emissions by 2050, as set forth in the GWSA, and to achieve the sector-specific emissions reductions established in the CECP for 2025 and 2030.[10]

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[10] In addition to the GWSA, the Commonwealth has enacted An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act"), and An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 ("2022 Clean Energy Act"). The GWSA, as amended by the 2021 Climate Act and implemented by the Secretary of EEA, requires the Commonwealth to reduce GHG emissions between 10 and 25 percent from 1990 levels by 2020, at least 50 percent from 1990 levels by 2030, at least 75 percent from 1990 levels by 2040, and achieve net-zero emissions by 2050 with a gross reduction in emissions of 85 percent from 1990 levels. G.L. c. 21N § 4; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020) (setting a legally binding statewide limit of net-zero GHG emissions by 2050, defined as 85 percent below 1990 levels); State of the State Address (January 2021) (Governor commits to achieving net zero greenhouse gas emissions by 2050), available at https://archives.lib.state.ma.us/handle/2452/816469 (last visited November 29, 2023). The CECP for 2025 and 2030 set sector-specific emissions reduction targets, as mandated by the 2021 Climate Act, setting an emissions reduction target for residential heating and cooling of 29 percent by 2025 and 49 percent by 2030 and an emission reduction target for commercial and industrial heating and cooling of 35 percent by 2025 and 49 percent by 2030 (2025/2030 CECP at 23). The 2025/2030 CECP and supporting information including sublimits is available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

As we chart the path for this transition, we emphasize that nothing we do here is intended to jeopardize the rate recovery of the billions of dollars of existing investments in natural gas infrastructure by the LDCs operating within the Commonwealth. Traditional notions of the regulatory compact continue to apply to those investments and, accordingly, there generally must be some demonstration of imprudence before recovery of existing investments can be challenged. At the same time, however, it is fair to say that a different lens will be applied to gas infrastructure investments going forward. The Department will be examining more closely whether such additional investments are in the public interest, given the now-codified commitment toward achieving Commonwealth's target of achieving net-zero GHG emissions by 2050 and the urgent need to address climate change. In this "beyond gas" future, we will be exploring and implementing policies that are geared toward minimizing additional investment in pipeline and distribution mains and achieving decarbonization in the residential, commercial, and industrial sectors.

The ambitious mandates established by the Commonwealth require gas LDCs to move beyond "business as usual" in their gas system planning, whether involving proposed expansion of service to new areas or investments necessary to maintain the safety of existing natural gas infrastructure. As discussed in subsequent sections of this Order, we are acting, within our existing statutory authority, to discourage further expansion of the natural gas distribution system. We will do so by revisiting the "public interest" standard we apply in evaluating proposed expansions, by examining the line extension policies followed by LDCs that may be inconsistent with the broader public policy of achieving necessary GHG reductions, and by encouraging consideration of zero-carbon alternatives, such as electrification and thermal networked systems, to traditional gas system capital investments.

With respect to maintenance of the existing natural gas infrastructure, our "beyond gas" future will similarly involve close scrutiny of the extent to which additional investment is necessary, with an eye toward minimization of costs that may be stranded in the future as decarbonization measures are implemented in the natural gas industry. In particular, we will generally require the examination of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation.[11] Going forward, LDCs will have the burden to demonstrate the consideration of NPAs as a condition of recovering additional investment in pipeline and distribution mains. As discussed in later sections of this Order, we will continue to explore opportunities for strategic and targeted decommissioning of portions of LDC service territories, through demonstration projects deploying both electrification and thermal network technologies.

As in the case of the transition to clean energy in the electricity sector, the decarbonization of the natural gas industry may result in higher costs being imposed on ratepayers. Given the urgency of addressing the climate crisis, however, we are reluctant to slow the pace at which the transition must occur due to concerns about affordability for

11 The comprehensive analysis of NPAs that we envision incorporates many of the elements identified in the Attorney General's proposed "investment alternatives calculator" and the "geographic marginal cost analysis" proposed by DOER, both of which are discussed later in this Order.

low- and moderate-income utility customers. Rather, the Department will address these issues in a separate proceeding, to be commenced later this year, dedicated toward examining innovative solutions to address the energy burden and affordability, such as capping energy bills by percentage of income or offering varying levels of low-income discounts, that have been implemented in other jurisdictions. We are confident that we can develop a solution—which likely will require a change in our statutory authority—that will allow us to address affordability issues in an effective manner and still enable us to achieve the necessary progress toward the Commonwealth's GHG emission reduction limits.

The transition of the natural gas industry involves other important considerations that we will need to address in a thoughtful and deliberate manner. As the Commonwealth accomplishes greater penetration of building electrification and distributed energy resources, we need to prioritize opportunities for residents of environmental justice populations[12] to benefit from moving beyond gas. This includes electrification and thermal network projects as well as workforce development and employment prospects for people historically left out

[12] In Massachusetts, an environmental justice population is a neighborhood where one or more of the following criteria are true: (1) the annual median household income is 65 percent or less of the statewide annual median household income; (2) people of color make up 40 percent or more of the population; (3) 25 percent or more of households identify as speaking English less than "very well"; (4) people of color make up 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income. Executive Office of Energy and Environmental Affairs Environmental Justice Policy at 4 (2021). See https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts (last visited November 29, 2023).

of the clean energy transition (e.g., women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, people who were formerly incarcerated). We also will work with the LDCs to encourage workforce development training and employment opportunities for gas workers and steelworkers to participate in a just transition away from fossil fuels. Thermal network projects, for example, offer attractive opportunities for workers in the gas industry to perform similar work in the installation of the infrastructure to deliver decarbonized heating and cooling solutions to residential and commercial customers.

Finally, as is apparent from the vast number of issues addressed in this Order, developing a regulatory framework to guide the transition of the natural gas industry in Massachusetts is an exceedingly complex undertaking. It involves fundamental ratemaking issues regarding the continued financial viability of LDCs and preserving their ability to raise capital on reasonable terms, as well as developing an orderly means of recovering in rates the billions of dollars in existing investment in natural gas infrastructure while maintaining the safety of the gas distribution system so long as natural gas continues to be delivered through it. It involves maintaining the affordability of energy services, and being particularly mindful to avoid burdening low- to moderate-income households that may be left behind—and potentially bearing a greater burden of the fixed costs of maintaining existing natural gas infrastructure—as more affluent households transition away from natural gas appliances. It involves recognizing the potential for the disproportionate distribution of the negative impacts associated with building, operating, and maintaining gas infrastructure. And it involves addressing the workforce issues associated with a gradual decommissioning of the existing natural gas distribution system. As we continue to develop the regulatory framework in subsequent proceedings following the issuance of this Order, we emphasize the importance of the continued involvement of all relevant stakeholders in the process. It is important, for example, for LDCs to move beyond "business as usual" practices toward active participation in developing innovative solutions to achieving the clean energy future codified in the Commonwealth's GHG emissions reduction targets. These exceedingly complex issues can be addressed effectively only with the broad participation of all the constituencies affected by this transition. We look forward to exploring these issues collectively in future proceedings.

IV. SCOPE AND AUTHORITY

The Department has broad authority to supervise gas companies pursuant to G.L. c. 164, § 76; Massachusetts Electric Company v. Department of Public Utilities, 419 Mass. 239, 245 (1994). It is well established, however, that the Department's general supervisory authority cannot arise from a vacuum. Massachusetts Oilheat Council, Inc., D.T.E. 00-57, at 6-7 (2001) citing Massachusetts Electric Company, 419 Mass. at 246.

The Legislature has taken steps to focus the Department's regulatory mandate on GHG emissions reductions in addition to its traditional concerns of ensuring safety, security, reliability, equity, and affordability. Both the 2021 Climate Act and 2022 Clean Energy Act include changes to the Department's regulatory authority over gas companies. In the 2021 Climate Act, the Legislature added Section 1A to G.L. c. 25, which provides:

> In discharging its responsibilities under [chapter 25] and chapter 164, the department shall, with respect to itself and the entities it regulates, prioritize safety, security, reliability of service, affordability, equity and reductions in

> greenhouse gas emissions to meet statewide greenhouse gas emission limits and sublimits established pursuant to chapter 21N.

The 2021 Climate Act also revised G.L. c. 21N, § 6, to charge the Secretary of EEA with establishing programs to meet GHG emissions limits and sublimits and implement the roadmap plans established by G.L. c. 21N. In addition, the 2022 Clean Energy Act amended G.L. c. 164, § 141, which now directs the Department, in all decisions or actions regarding rate designs, to consider, among other things, the impact of such decisions or actions on the reduction of GHG emissions as mandated by G.L. c. 21N to reduce energy use.

Recent legislation has not, however, amended or repealed other statutes that govern the Department's regulation of the natural gas industry. As we note in this Order, the Department may revisit its own precedent and standards of review in certain areas, and in other areas, legislative action may be required for the Department to be able to implement change or pursue particular pathways for achieving the Commonwealth's 2050 targets. For example, G.L. c. 164, § 30, establishes Department review of an LDC's petition to expand its service territory, which the Department has evaluated under a public interest standard. An Act Relative to Gas Leaks, St. 2014, c. 149, was enacted on June 26, 2014 ("Gas Leaks Act") and codified the uniform gas leaks classifications at G.L. c. 164, § 144; gas system enhancement plans ("GSEPs") at G.L. c. 164, § 145; and required the Department to, on or before January 1, 2015, authorize gas companies "to design and offer programs to customers which increase the availability, affordability, and feasibility of natural gas service for new customers." St. 2014, c. 149, § 3. In addition, the 2022 Clean Energy Act mandates that DOER establish a demonstration project in which up to ten municipalities may adopt zoning ordinances that restrict fossil fuel use in the construction sector. St. 2022, c. 179, § 84(b). As part of the demonstration project, DOER must collect data from the participants and submit reports to the Legislature every two years that include recommendations for the continuation or termination of the demonstration project. St. 2022, c. 179, § 84(e).

Finally and most specifically to our consideration of the Reports, Net Zero Enablement Plans, and other submissions in this proceeding, Section 77 of the 2022 Clean Energy Act provides:

> Notwithstanding any general or special law or rule, regulation or order to the contrary, the department of public utilities shall not approve any company-specific plan filed pursuant to the DPU Docket No. 20-80, Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, prior to conducting an adjudicatory proceeding with respect to such plan.

St. 2022, c. 179, § 77. Based on this clear directive, the Department will not approve the Net Zero Enablement Plans and/or the Model Tariff submitted by the LDCs in this investigation but will identify future adjudicatory proceedings and filings where we may properly consider company-specific plans.

The Department does not cite the above statutes as obstacles to the regulatory principles articulated in this Order. Rather, we do so only to acknowledge that our authority as a regulatory agency is bound by the limits established by law. Where pathways or proposals are inconsistent with existing statutes, the Department will note where additional legislative change or authority is necessary.

V. DECARBONIZATION REPORTS

A. Pathways to Net Zero

At the direction of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC, analyzing the feasibility of each decarbonization pathway identified by the Roadmaps. D.P.U. 20-80, at 3-5. In an effort to allow for meaningful comparisons among the LDCs and to ensure the consideration of all decarbonization strategies, the Department required the Consultants to identify any pathways not examined in the Roadmaps and employ consistent methods and considerations to analyze decarbonization opportunities for each individual LDC. D.P.U. 20-80, at 5. The Department instructed the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing for each identified pathway, among other requirements. D.P.U. 20-80, at 5-6.

To fulfill this requirement, the LDCs submitted the Pathways Report, which provides eight pathways designed to reflect different futures[13] for the LDCs and their customers

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[13] The eight pathways are not forecasts, but rather narratives that allow for the identification and comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Pathways Report further notes that analyzing decarbonization pathways out to 2050 involves a multi-decade horizon that is inherently assumption-driven and uncertain across several factors, including cost, consumer behavior, technology development, deployment, and other factors (Pathways Report at 27).

(Pathways Report at 11). Each of the eight pathways achieves the Commonwealth's goals of 90 percent gross GHG emissions reductions and net-zero GHG emissions by 2050 compared to 1990 levels, as well as the interim statutory GHG emissions reduction goals of 50 percent by 2030 and 75 percent by 2040 (Pathways Report at 11, 48). Similar to the 2050 Roadmap, all pathways have approximately 4.5 million metric tons of gross economy-wide, non-energy emissions[14] remaining in 2050 (Pathways Report at 48).

The eight pathways include the deployment of seven space-heating technologies,[15] and leverage various levels of renewable fuels, energy efficiency,[16] and building electrification technologies (Pathways Report at 31, 49-57). The eight decarbonization pathways impute a range of uses and roles for the gas system over time, spanning from 100 percent decommissioning of the system to large amounts of renewable gases being supplied to high-efficiency gas appliances (Pathways Report at 11, 63-75). In parallel, the Pathways

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[14] A more detailed description of GHG accounting (i.e., direct, electric sector, non-energy, and renewable fuels emission accounting methods) can be found in the Pathways Report, Appendix 1, at 21-28. Further information on common baseline economy-wide assumptions such as population growth and electrification of the transportation sector can be found in the Pathways Report, Appendix 1, at 8-9.

[15] The seven identified space-heating technologies include: (1) air source heat pumps; (2) ground source heat pumps; (3) hybrid heat pumps; (4) networked geothermal; (5) standard gas furnaces; (6) high efficiency gas furnaces; and (7) gas heat pumps (Pathways Report at 31).

[16] The Pathways Report states that energy efficiency is a foundational strategy to enable decarbonization of heating across all scenarios, reducing challenges associated with both electrification and decarbonized fuel-based strategies (Pathways Report at 47, 52-53, 110).

Report considers impacts on the electric system due to electrification-driven peaks and increased generation capacity (Pathways Report at 57-63).

The Pathways Report notes several key uncertainties across the pathways and develops sensitivity analyses to better capture assumptions in its modeling (Pathways Report at 34-35). Informed by a literature review,[17] the Pathways Report provides both optimistic and conservative views for the following six uncertainties: (1) incremental costs of cold-climate air source heat pumps ("cold-climate ASHPs"); (2) technical performance of cold-climate ASHPs; (3) incremental electric sector distribution system costs; (4) networked geothermal system installation costs; (5) cost and availability of renewable fuels;[18] and (6) opportunities for gas system cost avoidance (Pathways Report at 35). Additionally, the Pathways Report projects three pathways that would involve gas system departures through a geographically planned approach,[19] resulting in potential reductions in operation and maintenance expenses,

[17] The Consultants conducted a literature review of decarbonization strategies studied and implemented in the U.S. and internationally (Pathways Report at 28-29; App. 2).

[18] The Pathways Report defines renewable fuels as an umbrella term for renewably produced alternatives to fossil fuels, inclusive of renewable gases in the distribution system and renewable fuels in the transportation sector (Pathways Report at 9). The Report designates the following gases as renewable and having a net–zero GHG impact according to the Massachusetts GHG Inventory: (1) biomethane produced through anaerobic digestion or gasification; (2) hydrogen produced from electrolysis powered by renewable energy; and (3) synthetic natural gas produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9, 52, 110; App. 1, at 21-22). The Department does not necessarily consider biomethane, hydrogen, or synthetic natural gas to be renewable fuels.

[19] The Department further discusses geographically planned approaches and customer choice topics below in Section VI.B and Section VI.D.

GSEP expenditures,[20] and capital replacement costs (Pathways Report at 68-69). The Pathways Report further explores the cost and equity implications of combining the revenue requirement for the LDCs to maintain and operate both the gas and a networked geothermal system (Pathways Report at 72-75).[21]

The Pathways Report states that three pathways were modified from the Roadmaps: (1) high electrification, in which greater than 90 percent of the building sector electrifies primarily through the adoption of cold-climate ASHPs; (2) low electrification, in which 65 percent of the building sector electrifies with cold-climate ASHPs and gas customer count declines by 40 percent compared to today; and (3) interim 2030 CECP, in which the building sector electrifies at an accelerated pace, following the goals outlined in the Interim 2030 CECP (Pathways Report at 29-31). The 100 percent gas decommissioning pathway assumes that the building and industrial sectors fully electrify by 2050, with roughly 25 percent of the building sector converting to networked geothermal (Pathways Report at 31). The targeted electrification pathway assumes that greater than 90 percent of buildings electrify, with LDC customers converting to cold-climate ASHPs in a targeted approach (Pathways Report at 31). The networked geothermal pathway considers roughly 25 percent of the building sector

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[20] The Department allows LDCs to recover certain costs associated with the replacement of leak-prone pipeline infrastructure, pursuant to G.L. c. 164, § 145.

[21] The Pathways Report posits that a combined rate base would exhibit increased system costs, but theoretically would mitigate costs per customer as a larger portion of the customers remain that may share in the recovery of the combined system costs (Pathways Report at 73-75).

converting to networked geothermal systems, with remaining LDC customers using renewable gas[22] (Pathways Report at 31). The hybrid electrification[23] pathway assumes that greater than 90 percent of buildings electrify through cold-climate ASHPs paired with RNG (Pathways Report at 31). Lastly, the efficient gas equipment scenario assumes that the building sector largely adopts high-efficiency gas appliances supplied by a combination of renewable gas, with the industrial sector converting to dedicated hydrogen pipelines (Pathways Report at 31). Table 1 below contains a summary of each decarbonization pathway.

Table 1: Key Narratives by Decarbonization Pathway (Pathways Report at 29-32)

Pathway	Overview
Low Electrification (inspired by 2050 Decarbonization Roadmap "Pipeline Gas")	High electrification in the transportation sector. Buildings partly electrify. Building sector electrifies 65 percent of buildings through the adoption of ASHPs. Gas customer count declines by 40 percent compared to today.
High Electrification (inspired by 2050 Decarbonization Roadmap "All Options")	High electrification in both buildings and transportation sector. Building sector electrifies more than 90 percent primarily through the adoption of ASHPs.
Interim 2030 CECP	Accelerated electrification and building shell measures based on the interim 2030 building sector target.

22 The Pathways Report defines "renewable gas" as "an umbrella term referring to renewably produced alternatives to natural gas that can be blended into the distribution pipeline system" (Pathways Report at 9, App. 1, at 15). Under this definition, renewable gases include biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and synthetic natural gas ("SNG"), further defined and discussed in Section VI.C of this Order (Pathways Report at 9, App. 1, at 15).

23 The Pathways Report describes hybrid electrification as a space heating strategy that combines electric heat pumps with a gas or fuel oil backup that can be powered by renewable fuels (Pathways Report at 8).

Hybrid Electrification	Heat pumps are paired with gas or fuel oil backup to mitigate electric sector impacts. More than 90 percent of buildings electrify through ASHPs paired with renewable gas back-up (hybrid heat pumps) that supply heating in cold hours of the year.
Networked Geothermal	Part of the gas system is strategically replaced by networked geothermal systems. LDCs evolve their business model and convert +/- 25 percent of the building sector to networked geothermal systems. Remaining gas customers use renewable gas as their main source of heating by 2050.
Targeted Electrification	Part of the gas system is strategically decommissioned with customers adopting ASHPs. More than 90 percent of buildings are electrified through a combination of technologies. LDC customers converting to ASHPs do so in a "targeted" approach.
Efficient Gas Equipment	Building sector will adopt increasingly efficient gas appliances supplied by decarbonized gas. The industrial sector converts to dedicated hydrogen pipelines.
100 Percent Gas Decommissioning	Building sector and industry will fully electrify allowing for 100 percent decommissioning of the gas distribution system. Building and industrial sectors fully electrify by 2050. +/- 25 percent of the building sector converts to networked geothermal systems.

Developed with input from both LDCs and stakeholders, the eight pathways and their associated projected cumulative energy system costs (in 2020 dollars)[24] are calculated as follows: (1) high electrification, $87 billion to $111 billion; (2) low electrification, $73 billion to $95 billion; (3) interim 2030 CECP, $93 billion to $121 billion; (4) 100 percent gas decommissioning, $94 billion to $135 billion; (5) targeted electrification,

24 The Pathways Report calculates costs on a levelized basis, including a society-wide discount factor of 3.6 percent, noting that the study does not quantitatively consider the social costs of carbon or avoided costs related to potential health or environmental damages resulting from climate change (Pathways Report, App. 1, at 62).

$73 billion to $109 billion; (6) networked geothermal, $81 billion to $124 billion; (7) hybrid electrification, $63 billion to $92 billion; and (8) efficient gas equipment, $66 billion to $105 billion (Pathways Report, App. 1, at 62-65). The Pathways Report further presents cumulative energy system costs both annually and by decade relative to a reference scenario that does not meet the Commonwealth's 2050 climate targets, delineating the following cost components: (1) demand-side capital; (2) electricity supply; (3) gas system; (4) natural gas commodity costs; (5) liquid renewable fuels commodity costs; (6) renewable gas commodity costs; and (7) networked geothermal installation costs (Pathways Report at 13-14, 26-27, 79-82; App. 1, at 62, 65-66).

Further, the Pathways Report offers an evaluation of the feasibility and level of challenge[25] expected for each pathway across the following criteria: (1) cumulative energy system costs; (2) technology readiness; (3) air quality; (4) workforce transition; (5) customer practicality; (6) near-term customer affordability; (7) long-term customer affordability; and (8) customer equity (Pathways Report at 11-12, 76-79, 84-108). The Pathways Report states that all pathways were assumed to comply with Department and industry standards for safety and reliability (Pathways Report at 11-12, 77, 87-91).

Lastly, the Pathways Report presents several low-regret strategies and commonalities across the LDCs, while highlighting the need for further research and development ("R&D")

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[25] The Pathways Report defines challenge as the magnitude of change from current industry or customers practices and/or amount of policy intervention required (Pathways Report at 76).

and key distinctions among the LDCs (Pathways Report at 109-115). In conclusion, the Pathways Report finds that all pathways imply transformational changes for the Commonwealth, the LDCs, and their customers, and that strategies that use both the gas and electric systems to deliver low-carbon heat to a portion of the buildings in Massachusetts show a lower level of challenge across a range of evaluation criteria (Pathways Report at 11, 109).

B. Stakeholder Comments Concerning the Pathways Report

Many commenters disagree with the Pathways Report's conclusion that pathways utilizing both the gas and electric systems actually would present a lower level of challenge to the Commonwealth in reaching its climate commitments. For example, the Attorney General contends that the lower overall costs reported for the hybrid electrification pathway rest on unsound and unproven assumptions, arguing that the beneficial impacts of hybrid electrification on electric system infrastructure additions could be attained by focusing on building electrification in the near term. (Attorney General Technical Comments[26] at 6-8, 19-21 (May 6, 2022)). Although DOER acknowledges significant alignment between the Pathways Report and the 2050 Roadmap, DOER calls on the Department to acknowledge that electrification is the dominant strategy specified in the 2025/2030 CECP, and to find that the LDCs' proposed plans and framework are not sufficient to achieve decarbonization (DOER

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[26] The Office of the Attorney General's Initial Stakeholder Comments on Consultants' Technical Analysis of Decarbonization Pathways Report (May 6, 2022).

Comments at 6-7 (May 6, 2022) ("DOER Initial Comments"); DOER Comments at 6-8 (October 17, 2022) ("DOER Final Comments")).

Other commenters opine that electrification should not be the Commonwealth's sole decarbonization strategy, arguing that hybrid pathways are necessary for preserving optionality as renewable generation increasingly comes online (see, e.g., Associated Industries of Massachusetts ("AIM") Comments at 2 (June 17, 2022); Shell USA, Inc. Comments at 4-5 (May 6, 2022); Tufts Medicine Lowell General Hospital Comments at 1 (July 22, 2022); Lahey Hospital and Medical Center Comments at 1 (July 15, 2022); SFE Energy Massachusetts, Inc. ("SFE Energy") Comments at 3 (May 6, 2022)). Similarly, the National Fuel Cell Research Center calls for further quantification of the value of the increased reliability and resilience that could be provided by decarbonized gas and electric systems (National Fuel Cell Research Center Comments at 2 (May 6, 2022)).

Numerous commenters criticize the Pathways Report's assumptions regarding the availability, pricing, and emissions of renewable fuels (see, e.g., Attorney General Technical Comments at 8-19; Sierra Club Comments at 8-9 (May 6, 2022) ("Sierra Club Initial Comments"); Acadia Center Comments at 7-15 (May 6, 2022) ("Acadia Center Initial Comments")). The Attorney General notes that the annual volumes of RNG needed in Massachusetts by 2050 under a hybrid electrification pathway is roughly 70 trillion British thermal units ("TBtu"), whereas the total available RNG output nationwide as of 2020 was only 50 TBtu (Attorney General Technical Comments at 9). The Attorney General argues that both the exponential growth in RNG volumes and the practicality of Massachusetts securing a population-weighted "fair share" of 3.7 percent of all RNG volumes east of the Mississippi River are unrealistic (Attorney General Technical Comments at 9-12; Attorney General Final Comments at 20-21 (October 14, 2022)). Several other commenters question the availability and market clearing price of RNG modeled under the hybrid electrification pathway (see, e.g., Sierra Club Initial Comments at 10-12; Acadia Center Initial Comments at 10-15).

Relatedly, several commenters argue that the Pathways Report repeats known flaws in Massachusetts GHG Inventory[27] accounting, questioning whether renewable fuels are truly carbon neutral when combusted, and if upstream emissions related to the extraction and transmission of fuels should be counted (see, e.g., Acadia Center Initial Comments at 4-10; Sierra Club Initial Comments at 8; LexCAN Advocacy Committee Comments at 1 (May 9, 2022)). Some commenters question the leakage rates associated with the existing gas system, demanding greater transparency regarding leakage rates and lost and unaccounted for gas volumes (see, e.g., "Interested Persons"[28] Comments at 2-4; CLF Comments at 11, 27-31

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[27] Information about the Massachusetts GHG Inventory is available at https://www.mass.gov/lists/massdep-emissions-inventories (last visited November 29, 2023).

[28] On October 14, 2022, individuals associated with the following organizations filed a joint set of comments as "interested persons": Greater Boston Physicians for Social Responsibility; Climate Reality Project Boston Metro Chapter; Gas Leaks Allies; Pipe Line Awareness Network for the Northeast; Fore River Residents Against the Compressor Station; Mothers Out Front; Ashland Sustainability Committee; Sierra Club; Acadia Center; Gas Transition Allies; Brookline GreenSpace Alliance; Emerald Necklace Conservancy; Elders Climate Action Massachusetts; and No Pipeline Westborough.

(May 6, 2022) ("CLF Initial Comments"); CLF Final Comments at 4 (October 14, 2022) ("CLF Final Comments"); Acadia Center Comments at 7). Finally, several commenters call for the use of a 20-year global warming potential ("GWP") value for methane, consistent with the most recent Intergovernmental Panel on Climate Change Fifth Assessment Report (see, e.g., CLF Initial Comments at 28; Acadia Center Initial Comments at 6-7).

Additionally, numerous commenters argue that the Pathways Report fails to vigorously pursue potential gas infrastructure cost savings, such as reduced GSEP spending and more optimistic networked geothermal cost assumptions (see, e.g., Attorney General Technical Comments at 21-23; CLF Initial Comments at 12, 51-53; Sierra Club Initial Comments at 20-21). Several commenters criticize the hybrid electrification pathway as being potentially skewed toward lower system-wide costs, noting that the Pathways Report's lower level of building shell retrofits and inclusion of residential hybrid fuel oil/ASHPs does not allow for an apples-to-apples comparison across pathways (see, e.g., Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5). Lastly, several commenters criticize the Pathways Report's consideration of health and air quality impacts, arguing that combining indoor and outdoor air quality into a single metric masks the risk of maintaining gas appliances in homes to the health of children, the elderly, environmental justice populations, and people with underlying health conditions (see, e.g., Greater Boston Physicians for Social Responsibility Comments at 7-9 (May 2, 2022); Massachusetts Medical Society Comments at 2-3 (May 3, 2022)).

C. LDCs Response to Stakeholder Comments

The LDCs reject the notion that the Pathways Report picks a preferred pathway, arguing that other pathways compare favorably to the hybrid electrification pathway, and that differences in the application of building shells and discount rates do not impact the Pathways Report's conclusions (LDC Joint Comments at 9, 40, 45-47). The LDCs contend the finding that decarbonization pathways that "strategically use the state's gas infrastructure alongside and in support of electrification are likely to carry lower levels of challenge" is not unique to this study, and that similar findings have been identified in both the U.S. and abroad (LDC Joint Comments at 9, 42-45). The LDCs maintain that the Pathways Report is a product of a significant amount of discussion and feedback from stakeholders, and that it is imperative for the Department and key stakeholders to approve the Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 13, 96).

The LDCs argue that the Consultants' recommendations draw from common strategies identified across all pathways and that suggestions that the benefits of hybrid electrification can be captured by balancing all-electric and conventional gas heat demands are at odds with a targeted electrification strategy that substantially reduces gas infrastructure investment (LDC Joint Comments at 9, 47-49). The LDCs maintain that the Pathways Report considers the potential for substantial avoided reinvestment in gas infrastructure, including reductions in GSEP spending and detailed consideration of networked geothermal potential (LDC Joint Comments at 8, 32-37). The LDCs assert that the alternative gas infrastructure cost comparisons provided by stakeholders are not comparable to those in the Pathways Report (LDC Joint Comments at 8, 37-38).

With respect to the availability and pricing of renewable fuels, the LDCs insist that the Pathways Report includes both optimistic and conservative ranges that are heavily derated to assess potential availability to Massachusetts and are based on the best available literature (LDC Joint Comments at 8, 19-26). The LDCs maintain that the Pathways Report's approach to pricing renewable fuels is consistent with similar industry studies in the Northeast, including the 2050 Roadmap (LDC Joint Comments at 8, 26-29). Additionally, the LDCs state that the Pathways Report's approach to emissions accounting is consistent with the Massachusetts GHG Inventory, 2050 Roadmap, and international reporting standards, and that the use of a 20-year GWP value for methane would require a reevaluation of the Commonwealth's 1990 emissions baseline (LDC Joint Comments at 9, 30, 49-53). Lastly, the LDCs argue that the Pathways Report's modeling of leakage rates is consistent with the official accounting framework used in the Massachusetts GHG Inventory and 2050 Roadmap, and that the Pathways Report sufficiently addresses qualitative health and air quality impacts (LDC Joint Comments at 9-10, 53-59).

D. Analysis and Conclusions

Consistent with the directives of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC analyzing: (1) the feasibility of each decarbonization pathway identified by the Roadmaps; and (2) any pathways not examined in the Roadmaps, among other requirements. D.P.U. 20-80, at 3-5. The Department required the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing, for each identified pathway. D.P.U. 20-80, at 5-6.

To fulfill these directives, the LDCs submitted the Pathways Report, which identifies and discusses eight decarbonization pathways designed to allow for the comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Department commends the LDCs and their Consultants for their comprehensive effort in estimating the costs and economy-wide GHG emissions reductions[29] involved in transitioning the natural gas system. The Department fully recognizes the difficulty in assessing these multidimensional challenges and expresses its appreciation for the comprehensive Pathways Report.

DOER notes significant alignment between the Pathways Report and the 2050 Roadmap, stating that the two documents demonstrate several common assumptions and outcomes (DOER Initial Comments at 6-8). However, commenters predominantly disagree over the Pathways Report's finding that strategically using the state's gas infrastructure

[29] For each pathway involving electrification strategies, the Consultants were directed to provide a transparent depiction of key assumptions used in the analysis and a calculation of GHG emissions reductions, inclusive of GHG emissions from generation source. D.P.U. 20-80, at 5. The Department finds that the Pathways Report appropriately addressed this request (Pathways Report at 48; App. 1, at 21-28).

alongside and in support of electrification is likely to carry lower levels of challenge, most typified by the hybrid electrification pathway (see, e.g., Attorney General Final Comments at 6-19; DOER Initial Comments at 8-10; LDC Joint Comments at 40-48). Any further attempt to quantify alternative fuels, electrification technologies, and their associated GHG emissions reductions in a generic sense, is beyond the scope of the current investigation. The Department makes no findings related to a preferred pathway or technology here, as such considerations need to be made in the context of the distinct service territories of each LDC.[30] The Commonwealth's dominant building decarbonization strategy, however, is electrification as noted in the 2025/2030 CECP.[31] Our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates and comply with the 2025/2030 CECP.

In doing so, the Department acknowledges that there is potential for further refinement to capture more fully the intricacies and granularity needed to achieve the Commonwealth's 2050 climate targets. Ultimately, the transition toward the Commonwealth's net zero targets will be one that is driven by the willingness and ability of residential, commercial, and industrial customers to support the Commonwealth's

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30 As noted above in Section IV, the Department must review LDC-specific plans in adjudicatory proceedings before approving any individual plan. St. 2022, c. 179, § 77.

31 2025/2030 CECP at 27, available at https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download (last visited November 29, 2023).

environmental goals and climate targets through investments in their homes, businesses, and transportation infrastructure. The Department seeks to expeditiously attain the GHG emissions reductions necessary to achieve these targets and will begin by more thoroughly addressing the six regulatory design recommendations below. Indeed, as we discuss in more detail in the next section, we recognize that new regulatory support strategies will be needed to minimize customer cost impacts regardless of which pathway, or combination of pathways, is pursued. After due consideration of the record, we find that the Pathways Report satisfies the Department's directives in opening this investigation in D.P.U. 20-80.

VI. REGULATORY DESIGN RECOMMENDATIONS

A. Introduction

The Consultants identify six regulatory design recommendations: (1) support customer adoption of and conversion to electrified/decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department here analyzes the merits of the various regulatory pathways proposed by the Consultants, and also uses this framework as a vehicle for identifying areas where we intend to pursue future investigation.

B. Support Customer Adoption of and Conversion to Electrified/Decarbonized Heating Technologies

1. Introduction and Summary

To meet the Commonwealth's climate targets, the decarbonization pathways will require significant levels of customer adoption of electrification and decarbonization heating technologies (Regulatory Designs Report at 19). The Regulatory Designs Report explains that certain pathways, such as high electrification, will require swift and early action to increase customer utilization (Regulatory Designs Report at 19). The Consultants recommend the following regulatory approaches to support customer use of electrification and decarbonization heating technologies: enhance and increase funding of energy efficiency programs; restructure electric and gas distribution rates; and revise customer service standards and procedures (Regulatory Designs Report at 20-24). These recommendations are discussed in detail below.

a. Energy Efficiency

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend increasing energy efficiency program budgets, enhancing the programs to include new measures and strategies, and finding additional sources of funding (Regulatory Designs Report at 21). The Regulatory Designs Report emphasizes that the decarbonization pathways will require the deployment of new strategies and technologies (Regulatory Designs Report at 21). Since some decarbonization pathways target entire customer groups rather than individual customers to convert from natural gas to full electric service, energy efficiency programs will need to expand to support new incentive offerings and targeted electrification of entire customer blocks (Regulatory Designs Report at 21). The Consultants recommend evaluating the potential benefits of avoiding gas system infrastructure costs as part of targeted electrification or geothermal demonstration projects in the calculation of cost-effectiveness (Regulatory Designs Report at 21). The Regulatory Designs Report further explains that other enhancements may be necessary, including customer education and awareness, adoption of decarbonization strategies and technologies, and market transformation initiatives targeted at contractors, distributors, and manufacturers (Regulatory Designs Report at 21).

In addition, the Regulatory Designs Report states that the pathways will require larger energy efficiency budgets to support the enhanced initiatives discussed above (Regulatory Designs Report at 21). Since the current energy efficiency programs already are funded by ratepayers through the energy efficiency surcharge ("EES"),[32] the Consultants recommend evaluating additional funding sources to increase budgets and better align the benefits and cost responsibilities for certain programs between gas and electric companies (Regulatory Designs Report at 21-22). Specifically, the Consultants suggest offsetting some costs through a financial transfer from electric to gas utilities under a dual energy agreement (Regulatory Designs Report at 21-22).[33] A dual energy agreement involves a benefit-sharing mechanism

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32 The EES is included in the Local Distribution Adjustment Factor ("LDAF") of a customer's bill (Regulatory Designs Report at 21).

33 The Consultants cite a "dual energy" agreement between a Canadian electric company, Hydro-Quebec, and Energir, a gas company, in which gas customers in targeted market areas are converted to electricity to operate on electric heat during

that allows for a financial transfer from the electric company to the LDC as compensation for its role in electrification (Regulatory Designs Report at 22). The Consultants claim that a financial transfer reflects the economic and reliability benefits of maintaining the gas system to support electrification for hybrid heating customers (Regulatory Designs Report at 22).

b. Restructuring of Electric and Gas Rates

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend examining electric and gas distribution rate policies to reflect the changing demand and infrastructure requirements of electrification (Regulatory Designs Report at 22-23). For example, the pathways analysis shows that increased use of electric heating shifts peak electric demand from summer to winter and, therefore, presents an opportunity to evaluate price signals associated with electric rates to reflect changing demand (Regulatory Designs Report at 22).

For electric distribution rates, the Consultants recommend exploring: (1) the potential of time-variant rates to reflect the cost of serving electricity demands during peak periods; and (2) critical peak-pricing rates that reflect the cost of serving higher electricity demands under extreme weather conditions (Regulatory Designs Report at 22). The Consultants explain that critical peak-pricing rates could be used to reflect the substantially higher cost of electricity generation, transmission, and distribution to meet demand during extreme weather

non-winter peak periods while operating on gas heat during winter peak periods (Regulatory Designs Report at 22).

conditions, and provide customers with an incentive to reduce electricity use during those weather conditions (Regulatory Designs Report at 22).

For gas distribution rates, the Consultants observe that the adoption of hybrid heating systems may change gas demand characteristics because these customers would be using the system only during peak winter periods (Regulatory Designs Report at 23). Because of this change, the Consultants suggest creating a rate class for customers with hybrid heating systems (Regulatory Designs Report at 23). The Consultants state that a hybrid rate class would establish rates to better reflect the costs associated with providing gas service exclusively during peak winter periods (Regulatory Designs Report at 23).

In addition to creating another rate class, the Consultants recommend changing the revenue decoupling mechanism ("RDM") (Regulatory Designs Report at 23-34). The current gas RDM is designed on a per-customer basis, which allows the LDCs to retain the incremental revenues associated with serving new gas customers to offset the incremental costs associated with those customers until distribution rates are reset (Regulatory Designs Report at 23-24). The Consultants explain that this mechanism has worked well with the historical increase in gas customers; most of the decarbonization pathways, however, anticipate a decrease in the number of gas customers over time (Regulatory Designs Report at 24). The Consultants recommend transitioning away from a revenues-per-customer approach to a reconciliation of total revenues (Regulatory Designs Report at 24). Under this approach, the LDCs would reconcile actual revenues and Department-authorized or target revenues rather than revenues per customer, and that reconciliation would include revenue from new customers (Regulatory Designs Report at 24).

c. Customer Service Standards and Procedures

The Consultants explain that certain decarbonization pathways will require updated customer service standards and procedures to support adoption of electrification and decarbonization technologies identified in the pathways analysis (Regulatory Designs Report at 24). Geographically targeted electrification, for example, would require all customers within a specific geographic area or neighborhood to convert from gas to electric or another alternative (Regulatory Designs Report at 24). The Consultants caution that such strategies may raise concerns over customer choice, cost, the LDCs' obligation to serve, and customer service protections (Regulatory Designs Report at 24). The Consultants recommend comprehensive measures to address various issues, including enhancing customer communication and education processes, expanding customer options for gas and electric services, providing financial support for customers, and fostering stronger relationships with contractors (Regulatory Designs Report at 24-25). These recommendations are aimed at facilitating and promoting the widespread adoption of electrification and decarbonization technologies among customers (Regulatory Designs Report at 24-25).

2. Summary of Comments

a. Energy Efficiency

Commenters agreed with increasing incentives and exploring new energy efficiency strategies to better support customer adoption of electrification and decarbonization heating technologies (see, e.g., Acadia Center Initial Comments at 21-22; OPOWER Comments at 3 (May 6, 2022)). Other commenters argue that energy efficiency incentives for gas appliances should be phased out (Sierra Club Comments at 21; CLF Initial Comments at 9). The Attorney General notes that the Department-approved 2022-2024 Three-Year Energy Efficiency Plans ("2022-2024 Three-Year Plans") include significant investments to promote the adoption of heat pumps, while also observing that the most recent plans already come with significant budget and bill impacts for customers (Attorney General Initial Comments,[34] App. C at 7). The Attorney General and Acadia Center support enhanced energy efficiency investment but encourage the LDCs to explore other funding sources beyond the EES to minimize customer bill impacts (Attorney General Initial Comments, App. C at 7; Acadia Center Initial Comments at 22-23). In addition to funding, commenters say workforce development needs further support to facilitate customer adoption (Attorney General Initial Comments at 54; Acadia Center Initial Comments at 22; HEET Comments at 7 (May 6, 2022) ("HEET Comments")). The Attorney General states that the Department should engage regularly with workforce stakeholders, through working groups or other means, to better inform the transition of gas distribution services (Attorney General Initial Comments at 54).

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[34] Regulating Uncertainty: The Office of the Attorney General's Regulatory Recommendations to Guide the Commonwealth's Gas Transition to a Net Zero Future (May 6, 2022).

The LDCs maintain that the Pathways Report does not adopt one pathway, but recommends energy efficiency as a low-regret strategy (LDC Joint Comments at 40-41). The LDCs reiterate that energy efficiency measures may decrease the impacts of electrification on the electric system and reduce demands for natural gas (LDC Joint Comments at 40-41). According to the LDCs, additional investment in energy efficiency will play a critical role in meeting the needs of an electrified economy (LDC Joint Comments at 6).

b. Rate Restructuring

Many commenters agree with the Consultants' recommendation to investigate changes to gas distribution rates and revenue decoupling (see, e.g., Attorney General Initial Comments at 38-39; Acadia Center Initial Comments at 23; and DOER Final Comments at 2). The Attorney General argues that the Department should conclude its investigation in Investigation to Review and Revise the Standard of Review and the Filing Requirements for Gas Special Contracts Filed Pursuant to G.L. c. 164, § 94, D.P.U. 18-152, and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). According to the Attorney General, gas special contracts[35] should demonstrate net benefits to customers, and that the customer's use of natural gas is no more harmful in terms of GHG and air pollutant emissions than the customer's alternative energy resource(s) (Attorney General Initial Comments at 41-43). The Attorney General also

[35] Gas special contracts allow LDCs to provide firm transportation service to customers at individually negotiated, off-tariff distribution rates. D.P.U. 18-152, Vote and Order Opening Investigation at 1 (2018).

recommends that the Department not permit LDCs to recover costs for marketing related to promoting gas service because these costs are not aligned with the Commonwealth's decarbonization goals (Attorney General Initial Comments at 41). Furthermore, the Attorney General asserts that any modifications to the current cost recovery mechanisms should consider equity, affordability, and preservation of customer choice (Attorney General Final Comments at 4).

Commenter RMI[36] posits that a hybrid heating scenario requires that customers do three things: electrify with heat pumps, retain utility gas backup, and use that gas backup sparingly (RMI Comments at 3 (May 6, 2022) ("RMI Initial Comments")). As a result, RMI argues, crafting an effective rate design for hybrid heating customers will be challenging given that to reduce emissions and remain economically viable, a hybrid rate design must both (1) recover the costs of the gas system without encouraging customers to use gas as their primary heating fuel, and (2) avoid customer departure from the gas system (RMI Initial Comments at 3). RMI argues that as gas demand declines and non-fossil gas is substituted for fossil gas, rising gas rates will become inevitable and may lead to significant cost recovery and equity challenges under a hybrid heating rate design (RMI Initial Comments at 3).

The LDCs maintain that there is still interest in natural gas service despite the momentum toward full electrification (LDC Joint Comments at 10). The LDCs acknowledge

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[36] Formerly "Rocky Mountain Institute" (RMI Initial Comments at 1).

concerns over increasing costs but reaffirm that the Regulatory Designs Report proposes potential rate designs to align equitably the benefits[37] and cost of hybrid heating (LDC Joint Comments at 75). Specifically, the LDCs contend that rate designs, such as a new hybrid rate class and critical peak pricing, will help incentivize customers to adopt and remain on hybrid heating systems (LDC Joint Comments at 75). The LDCs explain that a combination of customer education, financial support, and supportive policy initiatives will be necessary to spur the level of conversion needed for electrification modeled in each pathway (LDC Joint Comments at 10).

Additionally, the LDCs state that the potential of financial transfers from electric to gas utilities would help reflect the economic and reliability benefits of maintaining the gas system to aid the electric system during peak weather events (LDC Joint Comments at 75). The Sierra Club, however, opposes the sharing of costs between electric and gas customers (Sierra Club Initial Comments at 19; Sierra Club Comments at 12-13 (October 14, 2022) ("Sierra Club Final Comments")). The Sierra Club argues that electric customers subsidizing the decarbonization of the gas sector would constitute an inappropriate cross-subsidization given that the electric sector already has "borne its share of decarbonization costs" (Sierra Club Initial Comments at 19; Sierra Club Final Comments at 12-13).

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[37] The LDCs explain that hybrid electrification is beneficial because it allows customers to leverage their existing equipment as a backup heating system (LDC Joint Comments at 74).

The LDCs reaffirm that most of the decarbonization pathways will result in service to fewer gas customers over time (LDC Joint Comments at 90). The LDCs recommend revising the RDM from a per-customer basis reconciliation of actual and authorized revenues to a reconciliation of total revenues (LDC Joint Comments at 90, citing Regulatory Designs Report at 23-24). The LDCs agree that replacing the RDM per customer with a total revenues or revenue cap decoupling is better aligned with the Commonwealth's decarbonization goals (LDC Joint Comments at 90-91). The Attorney General likewise agrees with revising the RDM (Attorney General Initial Comments at 39).

c. Affordability and Customer Choice

Several commenters also expressed affordability concerns, particularly for low- and moderate-income ("LMI") customers. Many commenters called for the prioritization of LMI customers to ensure an equitable transition and protect them from bearing the increased energy burden associated with electrification (see, e.g., NCLC Comments at 32 (May 6, 2022) ("NCLC Initial Comments"); LEAN Comments at 2-3 (May 6, 2022) ("LEAN Initial Comments"); Sierra Club Final Comments at 12). Some commenters, such as Acadia Center, disagree with charging customers exit fees[38] to leave the gas system because it may hinder electrification affordability (see, e.g., Acadia Center Initial Comments at 24; RMI Initial Comments at 3). LEAN recommends increasing low-income discounts and offering an exemption from the bill impacts of accelerated deprecation for LMI customers (LEAN Initial

[38] An "exit fee" or "migration charge" which would be charged to customers leaving the natural gas system is defined and discussed further in Section VI.F.

Comments at 17). In sum, numerous commenters express concerns that the LDC transition plans may impose an unfair burden on LMI customers in the absence of regulatory intervention.

The Attorney General confirms that, absent regulatory reform, remaining gas customers will experience significant rate increases as other customers leave the system (Attorney General Initial Comments at 46). Many commenters agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., HEET Comments at 7; LEAN Initial Comments at 17). The Attorney General explains that LMI customers currently spend a higher percentage of their income on utility bills than any other income group (Attorney General Initial Comments at 48). The Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50). Specifically, the Attorney General states that there should be a cap on the amount an LMI customer is billed (Attorney General Initial Comments at 52). Other commenters agree that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., DOER Initial Comments at 15; LEAN Initial Comments at 18).

Regarding customer choice, many commenters support a full transition away from fossil fuels via electrification. A handful of commenters do not (see, e.g., Tufts Medicine Lowell General Hospital Comments at 1; Inovis Energy, Inc. Comments at 1-2 (July 13, 2022); Mass Coalition for Sustainable Energy Comments at 1 (October 6, 2022)). One commenter noted that full electrification should be contingent on adequate renewable energy production (Shell USA, Inc. Comments at 4). Other commenters support electrification alongside geothermal and other low-carbon heating options (see, e.g., CLF Initial Comments at 12; Martin Comment at 1 (May 6, 2022)). Commenters acknowledge the LDCs' obligation to serve current gas customers but suggest revising the obligation to serve standards (see, e.g., Pipeline Awareness Network for the Northeast, Inc. ("PLAN") Comments at 4 (May 6, 2022) ("PLAN Initial Comments"); CLF Initial Comments at 21). PLAN states that the obligation to serve criteria apply only to existing customers (PLAN Comments at 5 (October 14, 2022) ("PLAN Final Comments").

The LDCs reiterate that customer choice will drive the acceptance of electrification but maintain that there is public support for preserving the natural gas system (LDC Joint Comments at 93-94, citing Exh. DPU-Comm 2-13, Att.). The LDCs highlight the substantial upfront costs for electrification as a barrier to conversion (LDC Joint Comments at 95, citing Pathways Report, Figure 4, at 17). The LDCs state that the Net Zero Enablement Plans contain strategies to help educate customers around their energy options (LDC Joint Comments at 94). Furthermore, the LDCs assert that achieving the levels of electrification modeled in each pathway will hinge not only on customer education, but also on supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95). The LDCs view current and future pilot projects as an opportunity to test and evaluate different market transformation approaches, including various incentive strategies to facilitate customer implementation of electrification and decarbonization heating technologies (LDC Joint Comments at 96, citing Exh. DPU-Comm 5-6).

3. Analysis and Conclusions

a. Introduction

The Department recognizes that significant levels of customer acceptance of electrification and decarbonization technologies will be needed for the Commonwealth to achieve its climate targets. While LDCs already have begun to increase the level of customer implementation of energy efficiency and decarbonized technologies through their 2022-2024 Three-Year Plans, more will need to be done inside and outside of the energy efficiency rubric to prioritize electrification, equity, and workforce development (Regulatory Designs Report at 20). See also 2022-2024 Three-Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, at 42, 46-47, 51 (2022) ("2022-2024 Three-Year Plans Order"). The Consultants recommend enhancing energy efficiency programs and funding to incentivize customer participation; restructuring gas and electric distribution rates to reflect the changing demand and infrastructure requirements of electrification; and establishing new customer service standards and procedures to facilitate and promote the widespread use of electrification and decarbonization technologies among customers (Regulatory Designs Report at 20-21). Commenters offer a range of perspectives on the transition to cleaner energy sources, with a focus on mitigating the impact on customers, especially those with lower incomes, and the role of incentives, rate structures, and policy initiatives in shaping the energy landscape. We address these recommendations below.

b. Energy Efficiency

The Department recognizes the importance of programs with effective participant incentives to help facilitate increased electrification and use of decarbonization technologies. The LDCs have strategies to leverage their cost-effective energy efficiency plans and strategies to encourage electrification through heat pumps and other measures. 2022-2024 Three-Year Plans Order at 51-52. In addition, under the Green Communities Act,[39] three-year plans must achieve all cost-effective energy efficiency, pass the cost-effectiveness analysis using the total resource cost test,[40] direct 20 percent of budgets to low-income energy efficiency, minimize administrative costs, maximize competitive procurement, and be mindful of bill impacts on gas ratepayers. G.L. c. 25, § 21(b)(1). In addition, beginning with the 2025-2027 three-year energy efficiency plans, there shall be "no spending on incentives, programs or support for systems, equipment, workforce development or training as they relate to new fossil fuel equipment unless such spending is for low-income households, emergency facilities, hospitals, a backup thermal energy source for a heat pump, or hard to electrify uses, such as industrial processes." G.L. c. 25, § 21(b)(2)(xi). Further, the Department already must consider whether these plans are constructed to meet or exceed the GHG emissions reduction mandates set by the EEA Secretary pursuant to G.L. c. 21N,

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[39] An Act Relative to Green Communities, Acts of 2008, chapter 69, section 11.

[40] In determining cost-effectiveness, the calculation of benefits shall include the social value of GHG reductions, except in the cases of conversions from fossil fuel heating and cooling to fossil fuel heating and cooling. G.L. c. 25, § 21(b)(1).

§ 3B. Finally, the Department considers whether the proposed plans adequately prioritize safety, reliability, security, affordability, and equity. 2022-2024 Three-Year Plans Order at 84.

The 2022-2024 Three-Year Plans have made significant steps in promoting both energy efficiency and electrification through customer incentives and performance incentives. See 2022 Energy Efficiency Annual Reports, D.P.U. 23-60, Berkshire Gas Company, App. 1, at 2-3 (June 1, 2023). The Department expects the LDCs to continue expanding the scope of ambition in their three-year plans to promote reductions in overall energy usage that result in cost-effective programs, while balancing increased electrification to meet GHG emissions reduction targets.

At the same time, the Department remains concerned about customer bill increases associated with enhancing the Commonwealth's energy efficiency programs. The Regulatory Designs Report recommends minimizing the potential bill impacts of these program enhancements by using other funding sources, such as government funding, gas system exit fees, and financial transfers from electric to gas utilities (Regulatory Designs Report at 44 n.57; Exh. DPU-Comm 3-3). Since 2010, the Department has required gas three-year plans to include all other sources of funding that program administrators have pursued to help fund the energy efficiency programs.[41] Investigation by the Department of Public Utilities on

[41] In approving an energy efficiency funding mechanism for the electric program administrators, the Department must consider the availability of other private or public funds. G.L. c. 25, § 19(a)(3)(ii).

its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, App. A, § 3.2.2.1 (2021), ("Guidelines"). The Department reminds program administrators that this requirement to pursue non-ratepayer sources of funding is more important now than ever, especially for residential and small-business customers who disproportionately bear the burden of higher energy efficiency surcharges as compared to other rate classes. The Department, however, declines to implement exit fees or financial transfers as viable outside funding sources to offset the cost of expanding energy efficiency budgets. As discussed in Section VI.F below, the Department is concerned that charging an additional fee to exit the gas system may disincentivize customers from fully electrifying. At the same time, in the absence of a gas exit fee, residential and small business customers who are not able to leave the system may bear even higher energy bills. The Department is open to reviewing any alternative funding sources so long as they help facilitate a safe, reliable, and equitable transition for all ratepayers.

Lastly, in response to the Attorney General's recommendation to engage with workforce stakeholders, the Department recognizes that the utility and energy contractor workforce will play an integral role in customer acceptance of electrification and decarbonization technologies. Workforce development is essential to safe and reliable gas operations and will be at the forefront of the industry transition. As required by G.L. c. 25, § 19(d), the annual workforce development program budget of $12 million is explicitly allocated from the 2022-2024 Three-Year Plans to MassCEC to grow and diversify a clean energy equity workforce and market development program in the Commonwealth.[42] 2022-2024 Three-Year Plans Order at 42. The Department accepts that significant efforts will be required to develop strategies to train and ensure family-sustaining wages for a workforce to support the energy transition. It is critical to train current gas system workers for employment opportunities in the clean energy sector. It is also important that jobs are available in the clean energy sector to support workers who are women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, and people who were formerly incarcerated. A comprehensive workforce strategy requires solutions that ensure the well-being of workers and communities, create jobs, and contribute to a thriving and sustainable economy. This strategy should be viewed as part of a just transition framework.

The Department, therefore, strongly encourages the LDCs to engage with other stakeholders, including labor unions, MassCEC, and existing workforce development programs, to establish a just transition framework for gas industry workers and people who have largely been left out of the clean energy workforce to start training for jobs that support

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42 General Laws c. 25, § 19(d), added by the 2021 Climate Act, requires the Department to annually collect and transfer not less than $12 million to MassCEC for the clean energy equity workforce and market development program established pursuant to G.L. c. 23J, § 13. MassCEC states that this funding will be used for assisting environmental justice populations to plan and develop career training programs for employment in high demand clean energy occupations, and to provide support for expansion and creation of minority- and women-owned business enterprises in business categories critical to state climate targets. Massachusetts Clean Energy Center Request for Fiscal Year 2023 Funding Pursuant to G.L. c. 25, § 19(d), D.P.U. 22-75, Letter Order at 1 (June 27, 2022).

electrification and decarbonization. The LDCs shall provide an update on this just transition framework in their future Climate Compliance Plans, which the Department details in Section VI.G below.

c. Rate Restructuring

The LDCs propose evaluating alternative rate designs to better reflect the changing demand and infrastructure requirements of electrification and agree with the recommendation to change the RDM structure (Regulatory Designs Report at 22-23). The Department supports the alignment of LDC rate designs with climate objectives and GHG reduction compliance pathways.[43] In particular, the Department agrees with the recommendation to replace the current per-customer RDM with a total revenues or revenue cap decoupling mechanism. The Department finds that a revenue cap approach, which subsequently disincentivizes LDCs to expand their gas customer base, better aligns with the policies of the Commonwealth expressed in current climate laws. The Department directs each of the LDCs to propose an RDM that implements this approach in its next rate case. The Department also encourages the LDCs to evaluate and propose alternative rate resigns and other cost recovery mechanisms that are consistent with the direction provided in this Order.

The Department acknowledges that the LDCs and Consultants identify hybrid heating systems as a low-regret strategy toward decarbonization and takes notice of the significant

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43 When considering new rate designs, the Department is required to take into consideration the reduction of GHG emissions pursuant to the 2022 Clean Energy Act. G.L. c 164, § 141.

uptick in utilization of heat pumps under the current three-year plans.[44] As we discuss in Section VI.D, however, the Department is not persuaded that pursuit of a broad hybrid heating strategy that would necessitate maintenance of the natural gas system to support backup heating systems is a viable path forward. Given improvements in technology, the Department expects that cold-climate heat pumps generally will eliminate the need for backup heating systems. During this transition period, however, the Department accepts that customers may elect to retain their previous backup heating systems, such as gas-fired boilers, to support heat pumps, as discussed further in Section VI.D. The LDCs shall continue to track customer heat pump installations. Further, the LDCs must work with their energy contractors and vendors to provide sufficient information to customers about the capabilities of heat pumps so they may reach a more informed conclusion about the true need for backup heating systems. If the LDCs propose a new rate design for hybrid heating customers, then they must strike a balance between recovering the costs of the gas system without encouraging customers to use gas as their primary heating fuel, thereby enabling

44 To date, three gas program administrators have filed mid-term modification requests in 2023 for additional funding partially due to a higher-than-expected demand for heat pumps (see Berkshire Gas Company, D.P.U. 23-93, Pre-Filed Testimony of Hammad Chaudhry and Jillian Winterkorn at 3-4; Liberty Utilities, D.P.U. 23-91, Pre-Filed Testimony of Kimberly Gragoo, Stephanie Terach, and Autumn R. Snyder at 6-7; Fitchburg Gas and Electric Light Company, D.P.U. 23-70, Pre-Filed Testimony of Cindy L. Carroll and Mary A. Downes at 6).

GHG emissions reductions while maintaining low operating costs to retain customers.[45] The Department will consider all other rate restructuring proposals on a case-by-case basis.

With respect to special gas contracts, we acknowledge the Attorney General's suggestion that the Department conclude its investigation in D.P.U. 18-152 and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). The Department agrees that the requirements for gas special contracts should be improved and refined, and that the ongoing investigation in D.P.U. 18-152 is the proper vehicle for the pursuit of any such changes. Given that D.P.U. 18-152 remains an open proceeding, we decline to address the specifics or potential outcomes here other than to acknowledge that a re-examination of gas special contracts is part of the portfolio of actions we are taking to facilitate the necessary transition of the natural gas industry.

Finally, we agree with the Attorney General that LDCs should not be permitted to include in rates any costs associated with marketing geared toward the promotion or expansion of gas service. As noted by the Attorney General, these costs are not aligned with the Commonwealth's decarbonization targets and any continued funding of such advertising or marketing by ratepayers is the type of "business as usual" operations of LDCs that must

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45 In the context of hybrid heating and a hybrid heating rate design, the importance of customer retention via low operating costs is so that increasing costs do not incent those customers most able to afford full electrification to pursue that option (or delivered fuels) while leaving lower-income customers on a rate that potentially would rapidly increase to account for fewer customers supporting the system (RMI Initial Comments at 2-3). This is inconsistent with an equitable transition.

cease. Moreover, this prohibition on ratepayer funding of gas marketing extends not only to initiatives undertaken directly by LDCs, but includes indirect efforts to promote either natural gas expansion or policies geared toward promoting natural gas expansion. If and to the extent LDCs wish to continue participating in such efforts, the associated costs will be borne entirely by shareholders.

d. Affordability and Customer Choice

The pace of customer transition to alternatives to natural gas is a significant uncertainty facing gas industry sales and revenue projections. Many commenters argued for the prioritization of LMI customers to ensure an equitable transition (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). The Attorney General contends that that the Department should consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50).

The Department agrees that the pace of customer transition to gas alternatives will depend on a suite of available incentives, education, legislative change, and market transformation activities. Ensuring an affordable and equitable transition will be among the most potentially challenging aspects of this undertaking. A mass exodus of gas customers has the potential to shock rates to the detriment of remaining ratepayers and reduce utility revenues, jeopardizing the LDCs' continued provision of safe and reliable service to remaining customers, as well as posing a potential general safety risk to the public at large. Conversely, less competition from alternatives may result in a slower pace of transition and delay the necessary achievement of the climate targets. The Department and LDCs will need to take steps to minimize the impacts of long-term competitive losses. The Department will address the practicality of such strategies through the remainder of this Order, including modification of line extension policies that assume long-term sales revenue, shifting revenue from traditional rate base to performance-based mechanisms that incent reduced emissions, and rate structures that protect LMI customers.

As to preserving customer choice, it is not clear that the Department has the statutory authority to prohibit the addition of new gas customers. It is the Department's long-standing policy, however, that an LDC need not serve new customers in circumstances in which the addition of new customers would raise the cost of gas service for existing firm ratepayers. Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988). An LDC must therefore first ensure that the incremental costs to expand its distribution network do not exceed the incremental revenues from such expansion to include the cost of expanding its distribution network in rates. Bay State Gas Company, D.P.U. 12-25, at 379 (2012); Boston Gas Company, D.T.E. 03-40, at 48 (2003). LDCs determine whether a main or service extension is economically feasible using a model to compare the estimated cost of the project to the estimated revenues over the expected useful life of the plant investment to ensure the internal rate of return exceeds the rate of return allowed in the Company's most recent base distribution rate case. See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 456-457 (2020) (reviewing the company's main extension policy in the course of analyzing a surcharge proposal pursuant to St. 2014, c. 149, § 3); Boston Gas Company, D.P.U. 89-180, at 16-17

(1990). When an investment needed to serve a new customer does not pass the internal rate of return test, the gas company may require the customer to pay a contribution in aid of construction ("CIAC") to make up the deficit. D.P.U. 19-120, at 456-457.[46] It thus appears that there is an opportunity to revise the process of making this cost determination, reviewing tariff provisions, and current LDC practices to disincentivize further customer expansion while still preserving customer choice to the extent necessary. These changes are further discussed in Section VI.E below.

C. Blend Renewable Gas Supply Into Gas-Resource Portfolios

1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs develop a procurement strategy to add renewable gas options to their resource portfolios (Regulatory Designs Report at 25). As used by the Consultants, "renewable gas supply" is an umbrella term that refers to renewably produced alternatives to natural gas that includes biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and SNG produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9; Regulatory Designs Report at 6, 25). The Consultants note that blending limited amounts of renewable gases into the pipeline could result in a reduction of GHG emissions without a corresponding substantial increase in overall gas costs (Regulatory Designs Report at 25). The Consultants recommend

[46] Property that has been contributed to a utility is not included in rate base. D.P.U. 12-25, at 380 n.220, citing Milford Water Company, D.P.U. 771, at 21 (1982); Oxford Water Company, D.P.U. 18595, at 18 (1976); Commonwealth Gas Company, D.P.U. 18545, at 2 (1976).

that the LDCs investigate the deliverability of biomethane, hydrogen, and synthetic gases from a broader range of resources and regions to clarify further their role in supporting the state's decarbonization goals and ensure that these fuels in fact can meet the requirements of the pathways (Regulatory Designs Report at 25). Finally, the Regulatory Designs Report recognizes that renewable gas does not meet the Department's least-cost standard (Regulatory Designs Report at 25). The Consultants make three specific recommendations intended to enable LDCs to incorporate renewable gas supply into the system: (1) update the forecast and supply planning standards to add renewable gas; (2) provide customers with an option to purchase renewable gas from the LDC; and (3) provide customers with an option to purchase renewable gas from third-party suppliers (Regulatory Designs Report at 25-26).

According to the Regulatory Designs Report, the Department should update its forecast and supply planning[47] standards to require a minimum level of renewable gas and

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47 Pursuant to G.L. c. 164, § 69*I*, every gas company shall file for the Department's approval a long-range forecast with respect to the gas requirements of its market area for the ensuing five-year period, consisting of the gas sendout necessary to serve projected firm customers and the available supplies necessary to meet the projected demand. Further, the Department reviews a gas company's five-year supply plan to determine whether the plan is adequate to meet projected normal-year, design-year, design-day, and cold-snap firm sendout requirements. Fitchburg Gas and Electric Light Company, D.P.U. 21-10, at 3 (2022).

Under its current standards, the Department determines if a company's projection method is reasonable based on whether the method is: (a) reviewable, that is, contains enough information to allow a full understanding of the forecast method; (b) appropriate, that is, technically suitable to the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to incorporate the cost of carbon in the LDCs' supply plan economic analysis (Regulatory Designs Report at 25). The Consultants posit that either a Renewable Heating Fuel Standard ("RHFS") or a Renewable Portfolio Standard ("RPS") could establish a minimum level of RNG, similar to the electric industry (Regulatory Designs Report at 25). The Consultants suggest that either the Legislature or the Department via a generic proceeding could authorize an RHFS or RPS, and that the minimum level of renewable gas could be set low initially to address concerns with availability and cost, with subsequent increases subject to these considerations (Regulatory Designs Report at 25-26). A second approach to updating the forecast and supply standards discussed by the Consultants is the addition of a cost of carbon to the supply planning economic analysis, which would provide an economic advantage to low-carbon supplies (Regulatory Designs Report at 26). As in the context of the RHFS and RPS option, the Consultants assert the cost of carbon initially could be set low to address supply availability, cost, or customer affordability considerations and then increased gradually subject to these considerations (Regulatory Designs Report at 26).

The Consultants' second recommendation for incorporating renewable gas into the system is to provide LDC customers who want to reduce their carbon emissions the option to purchase renewable gas directly from the LDC (Regulatory Designs Report at 26). In this scenario, the Department would approve a tariff through either an LDC-specific rate-setting

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occur. D.P.U. 21-10, at 3, citing Bay State Gas Company, D.T.E. 02-75, at 2 (2004); The Berkshire Gas Company, D.T.E. 02-17, at 2 (2003).

proceeding or through a generic proceeding applicable to all LDCs (Regulatory Designs Report at 26).

With respect to the third recommendation to facilitate use of renewable gas, the Regulatory Designs Report recommends that the Department provide customers with an option to purchase renewable gas from third-party suppliers via each LDC's delivery service (Regulatory Designs Report at 26). The Consultants posit that this approach may be appealing to customers, especially large commercial and industrial customers, seeking to purchase directly from a third-party supplier. The Regulatory Designs Report recognizes that a special tariff may be required to address interconnection requirements (Regulatory Designs Report at 26).

Finally, and applicable to all three design approaches discussed above, the Consultants recommend a procurement strategy that includes customer education, marketing, and incentives that promote the integration of renewable gas into the gas system. This would facilitate customer understanding of the benefits and cost implications of renewable gas and their options to incorporate it into their fuel mix (Regulatory Designs Report at 27).

2. Summary of Comments

Generally, commenters agree in their objections to the recommendations in the Regulatory Designs Report regarding renewable gas.[48] Numerous commenters raised issues

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48 While the Pathways Report refers to "renewable gas," commenters also refer to renewable natural gas or "RNG," which along with SNG and hydrogen, may also be referred to as "decarbonized gas" (Attorney General Initial Comments at 11-12). The

and concerns related to emissions, system upgrades and related costs, and the availability of alternatives.

The Attorney General argues that the Pathways Report overstates the availability of RNG and understates RNG's costs (Attorney General Technical Comments at 8-16; Attorney General Final Comments at 20). The Attorney General asserts that there is no credible basis to assume that RNG can be made available in Massachusetts at the volumes needed to support the gas use in 2050 assumed under the hybrid electrification scenario, and further that the Consultants significantly understate the costs of obtaining RNG (Attorney General Technical Comments at 8-16). The Attorney General argues that, in developing their price projections for RNG, the Consultants developed a weighted average price for RNG instead of pricing it at the incremental price of the marginal unit of supply (Attorney General Final Comments at 21). Moreover, the Attorney General asserts that the continued use of biomethane is inconsistent with the Commonwealth's policy as set forth in EEA's 2025/2030 CECP (Attorney General Final Comments at 21-22). The Attorney General also questions the Consultants' assumption that RNG is carbon neutral (Attorney General Technical Comments at 16-19). Further, the Attorney General notes that RNG and hydrogen, although emerging, are unproven and uncertain technologies that carry significant investment risks (Attorney General Initial Comments at 32). The Attorney General therefore recommends that

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Attorney General and others assert, however, that the term "decarbonized gas" is a misnomer (Attorney General Initial Comments at 11 n.48).

the Department ensure that investments in unproven or uncertain technologies are borne entirely by utility shareholders (Attorney General Initial Comments at 32).

DOER suggests that the Department consider R&D proposals intended to increase the supply of RNG and hydrogen (DOER Initial Comments at 11). DOER also proposes that the Department disallow long-term contracts that would lock customers into high-risk and high-cost resources for long periods (DOER Initial Comments at 16). Finally, DOER proposes that the Department should require the LDCs to complete R&D projects using RNG to demonstrate emissions reductions consistent with the GWSA methodology before it approves any long-term contracts for renewable gas or hydrogen (DOER Final Comments at 15).

Acadia Center argues that the proposals involving RNG: (1) fail to account for out-of-state emissions occurring during the productions and transmission of the fuels; (2) dramatically underestimate the level of methane leaks from the natural gas systems in Massachusetts; (3) assume that biofuels are GHG-neutral; and (4) underestimate the availability and price of RNG and hydrogen (Acadia Center Initial Comments at 5-15).

Similar to Acadia Center, Sierra Club asserts that the Consultants underestimate the levels of GHG emissions from RNG and SNG, and also underestimate the availability of and clearing prices for renewable gas (Sierra Club Initial Comments at 8-11). In addition, Sierra Club argues that hydrogen is an inefficient and unfeasible strategy to decarbonize buildings (Sierra Club Initial Comments at 14-17). Finally, Sierra Club argues that even if the LDCs' treatment of biofuels as zero-GHG emitting is consistent with both the Commonwealth's current GHG accounting methodologies and its 2050 Roadmap, that is an inadequate basis for assessing the relative merits of biofuel investments as part of a decarbonization strategy (Sierra Club Final Comments at 6-8).

CLF argues that there is insufficient evidence to support the claim that biomethane is a zero-emissions fuel over the course of its lifecycle (CLF Final Comments at 4). Regarding hydrogen, CLF argues that it is highly volatile and will have to be limited to applications and sectors that cannot be electrified (CLF Final Comments at 4). CLF contends that LDCs would have to prove that biomethane is a zero-carbon fuel before forecast and supply plan standards should be allowed to include RNG, or before customers should be given the option to purchase RNG from LDCs or from third parties (CLF Initial Comments at 14). CLF maintains that the Consultants' technical analyses around the impact of biomethane were based on assumptions not grounded in science or reality (CLF Initial Comments at 14). In addition, EDF contends that there is a good understanding of the climate and safety impacts of renewable fuels, noting that hydrogen emissions have global warming potential (EDF Comments at 6–8 (October 13, 2022) ("EDF Final Comments")).

Dozens of individual and group commenters raised concerns similar to those recited above, specifically arguing against the mandated use of RNG and/or hydrogen based on issues related to supply availability, GHG emissions, safety, and cost (see, e.g., Interested Persons Comments at 2-3; Elders Climate Action Massachusetts Comments at 1-3 (May 6, 2022); Callaway Comments at 1 (May 4, 2022); Fortuin Comments at 1-2 (May 6, 2022); Phillips Comments at 1 (May 6, 2022)).

The LDCs argue that RNG and other alternative fuel sources are a necessary component of any decarbonization future and that the path to net zero does not need to be a binary decision between fuel sources and a fully electrified system (LDC Joint Comments at 60). The LDCs contend that adding RNG to the supply portfolio will produce environmental benefits, contributing to achievement of the Commonwealth's objectives, and will improve supply availability and diversity, both critical gas supply planning considerations (LDC Joint Comments at 60-61). Further, the LDCs point out that to fully electrify, a significant overbuild of renewables will be required to ensure peak demand can be met by the electric network (LDC Joint Comments at 62). The LDCs assert RNG can complement electrification by supporting the intermittent nature of renewable generation resources like solar and wind (LDC Joint Comments at 62).

Regarding the various comments expressing skepticism that RNG can be scaled to the level needed and purchased at a reasonable cost, the LDCs state that they expect the availability of RNG to continue to grow as technologies to develop RNG continue to advance (LDC Joint Comments at 63). Finally, regarding the criticism that the Consultants treat renewable gases as carbon neutral, the LDCs assert that this approach is consistent with both the official GHG accounting methodology of the Commonwealth and the 2050 Roadmap (LDC Joint Comments at 30).

3. Analysis and Conclusions

The Consultants recommend that the LDCs develop a procurement strategy to add RNG supply to the resource portfolio. The Department has been presented with three specific means of enabling the LDCs to incorporate RNG supply into their gas system: (1) update the forecast and supply planning standards to incorporate RNG through either a RHFS/RPS or the addition of a cost of carbon; (2) provide customers with an option to purchase RNG from the LDC; and (3) provide customers with an option to purchase RNG from third-party suppliers (Regulatory Designs Report at 25-26).

Most commenters did not address directly the suggestion that the Department update the forecast and supply planning standards to incorporate RNG. Numerous comments did note, however, that RNG does not provide measurable benefits in terms of costs and emissions reductions.

Our policy regarding the LDCs' procurement of gas resources is well established. The Department first articulated its standard for commodity and capacity acquisitions in Commonwealth Gas Company, D.P.U. 94-174-A (1996), where the Department determined that to demonstrate that the proposed acquisition of a resource that provides commodity and/or incremental resources is consistent with the public interest, an LDC must show that the acquisition is (1) consistent with the company's portfolio objectives; and (2) compares favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation. D.P.U. 94-174-A at 27. In Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 22-32-C at 36 (2022), the Department also noted that we must consider whether the proposed acquisition is consistent with the GWSA and any applicable emissions limit or sublimit set by the Secretary of EEA. G.L. c. 25, § 1A. At this time, as we discuss below, we have been presented with no evidence convincing us to alter this gas procurement policy. On the contrary, we share the concerns raised by various stakeholders regarding costs, availability, and the treatment of renewable fuels as carbon neutral.

As the LDCs acknowledge, RNG currently does not meet the Department's least-cost supply planning standards given the higher cost of RNG relative to pipeline gas. Given this, the inclusion of RNG supplies in an LDC's resource portfolio would violate our goal of providing gas service at the lowest possible cost. Indeed, the higher cost of RNG raises customer affordability concerns as LDC rates will be higher than they otherwise would be if pipeline gas continued to be used.

We recognize that RNG and the use of hydrogen as a fuel are emerging technologies that have not yet been proven to lead to a net reduction in GHG emissions. The Consultants assume that RNG's emissions are carbon neutral under the Commonwealth's current GHG accounting framework (Regulatory Designs Report at 8 n.7). They acknowledge that if the GHG emissions accounting conventions change, however, the potential of RNG as a carbon-neutral fuel diminishes and its value in terms of decarbonization would be overstated (Pathways Report at 18 n.12). In our view, more studies are required in this area to support the claim that RNG is a zero-emissions fuel. For example, a full life-cycle analysis that considers all of the emissions profiles and captures emissions gains and losses throughout the entire production process may be necessary to determine the total carbon intensity of RNG.

Regarding the availability of RNG, we are not convinced that sufficient RNG stocks will be available to ensure the alleged potential environmental benefits. Record evidence shows that there is significant uncertainty regarding the availability of RNG (Pathways Report, App. 1, at 16). Indeed, the Consultants note that biomass resource availability in New England is relatively low compared to other regions in the United States. New England has an estimated 0.63 dry tons of feedstocks available per person per year, whereas the average availability of feedstocks for the U.S. as a whole, is 2.47 dry tons per person per year (Pathways Report, App. 1, at 15). According to the Coalition for Renewable Natural Gas, of the 300 RNG facilities in the U.S., only eight are located in New England.[49] In the long run, RNG supply shortages may lead to higher costs. For these reasons, we have no basis in the existing record for altering our existing gas procurement policy as established in D.P.U. 94-174-A to allow for the acquisition of RNG and or the imposition of a RHFS or cost of carbon in the LDCs' supply plan economic analyses. We recognize, however, that the technology is evolving and the process to produce RNG may possibly lead to measurable benefits in the future, particularly for hard-to-electrify industrial processes. We encourage LDCs to investigate all options that will lead to a reduction in their GHG footprint, including lifecycle emissions associated with system operations, and we will review any proposals that are consistent with existing standards as well as with the Commonwealth's GWSA and the 2021 Climate Act.

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49 See https://www.rngcoalition.com/?gad=1&gclid=Cj0KCQjwpc-oBhCGARIsAH6ote-K_4nSXK5AbiPbzM5IqeZD-AfyAg7WWyM5sfivAv_6_Q3Uvs9i4sYaAgadEALw_wcB (last visited November 29, 2023).

As the Commonwealth strives to achieve its 2050 climate targets, we envision that the long-term use of the natural gas distribution system generally will be limited to strategic circumstances where electrification is not feasible for all natural gas applications. For example, we recognize that some C&I customers require natural gas for process heat applications for which there are currently no electric-driven alternatives. It would therefore be necessary to make RNG and/or hydrogen available to this category of end-use customers.

Regarding the recommendation that gas customers be provided with the option to purchase RNG from their LDC or a third-party supplier, the Department has endeavored to develop a competitive natural gas supply market that would allow customers the broadest possible choice and provide all customers with an opportunity to share in the benefits of increased competition. See Natural Gas Unbundling, D.T.E. 98-32-B at 3, 4 (1999). We anticipate that there may be situations where customers would like to purchase RNG from their gas company or directly from a third-party supplier. We encourage LDCs to begin assessing customer interest in RNG and, if so, determine the associated demand load and begin developing educational and marketing material. While we support customer choice as it relates to RNG, we recognize that due to its nature and current technology, RNG is more expensive than conventional natural gas (Regulatory Designs Report at 25, 41). The inclusion of RNG-related costs in an LDC's supply portfolio costs—i.e., costs currently recovered under an LDC's seasonal cost of gas adjustment clause—would therefore increase the average cost of gas. To avoid any cross-subsidization issues, participation in such a program must be voluntary with all associated costs, including program administration costs, allocated and recovered solely from the participants. As we will not authorize a mechanism that would socialize the higher commodity cost of RNG, the Department expects that customers selecting RNG, regardless of whether it was procured from the LDC or a third-party supplier, will be responsible for the costs. We expect that the LDCs will inform potential customers of the cost of RNG, its lifecycle GHG emissions, and the likely bill impacts associated with their participation. To ensure that no costs associated with such a voluntary option are assigned to non-participants, the LDCs must keep a separate accounting of RNG costs and develop a voluntary RNG opt-in sales tariff outlining the provisions for service for Department review and approval. In summary, subject to the conditions above, we will allow the option for consumers to purchase RNG from an LDC or a third-party supplier.

The Department cautions, however, that RNG and hydrogen may require system upgrades due to the density of the fuels. If the LDCs need to upgrade their systems or incur additional interconnection and metering equipment costs to make these fuels available, all of the relevant system-upgrade costs, in addition to traditional costs borne by gas ratepayers, must be assumed by those who will take RNG supply and not by all customers. In summary, all costs associated with RNG are to be borne solely by utility shareholders or program participants.

The Department may review proposals for RNG or hydrogen pilot programs, as discussed below in Section VI.D. However, we agree with the Attorney General that RNG and hydrogen blending are new, unproven, and uncertain technologies. LDCs may research and assess these technologies, but until they prove to be a viable alternative to the business-as-usual model and support the Commonwealth's climate targets, any infrastructure costs associated with RNG and hydrogen will be the sole responsibility of the utility shareholders and not their customers.

D. Pilot and Deploy Innovative Electrification and Decarbonized Technologies

1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen (Regulatory Designs Report at 27-29). Further, the Regulatory Designs Report recommends that the Department develop guidance for review and approval of pilot projects and R&D programs, design additional cost recovery mechanisms, and track and report on performance metrics (Regulatory Designs Report at 29-30).

The Regulatory Designs Report explains that pilot opportunities for networked geothermal systems potentially could serve as strategic replacements for planned capital spending and be consistent with networked geothermal pilots approved for NSTAR Gas[50] and National Grid (gas);[51] however, the Regulatory Designs Report notes outstanding questions

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[50] On October 30, 2020, the Department approved a networked geothermal demonstration project proposed by NSTAR Gas to evaluate the technology in a mixed-use, dense urban environment. D.P.U. 19-120, at 138-156.

[51] On December 15, 2021, the Department approved a networked geothermal demonstration proposal from National Grid (gas). Boston Gas Company,

exist regarding the technical implementation, financing, and role of networked geothermal in avoiding gas infrastructure investments (Regulatory Designs Report at 27). The Regulatory Designs Report also recommends an investigation into the most optimal operation of hybrid heating systems to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs necessary to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). Finally, the Regulatory Designs Report recommends that LDCs pursue pilot opportunities to investigate the extent to which hydrogen can be added to their systems without the need for customer equipment or pipeline upgrades, engage in R&D opportunities related to the commercialization of synthetic gases, and explore certified natural gas, which may have lower upstream emission intensity (Regulatory Designs Report at 28-29).

The Regulatory Designs Report posits that an updated process for approval of pilot and R&D programs could facilitate the timely evaluation and deployment of decarbonized technologies better than a project-by-project approach (Regulatory Designs Report at 29).

D.P.U. 21-24, at 32-33 (2021). National Grid (gas) will prioritize the installation of networked geothermal systems that evaluate one or more of the following concepts: (1) the thermal performance and economics of shared loops serving a larger number of customers with more diverse load profiles than a networked geothermal project completed by its New York affiliate; (2) switching gas customers to geothermal energy as an alternative to leak-prone pipe replacement; (3) installing shared loops to manage local gas system constraints and peaks; and (4) installing shared loops to lower operating costs and GHG emissions for low-income customers and environmental justice populations. D.P.U. 21-24, at 3-4.

The Regulatory Designs Report explains that pilot and R&D programs could establish a process to track and report on performance metrics of interest, such as achievement of defined objectives; installation and service provider participation; customer education, interest and adoption experience; and role of the project in achieving decarbonization goals (Regulatory Designs Report at 30). The Regulatory Designs Report states that LDCs could recover the costs associated with additional pilots and R&D either through the local distribution adjustment clause or a new fully reconciling funding mechanism (Regulatory Designs Report at 30).

In this Order, we evaluate the potential of the four specific technologies recommended by the Consultants, both in the context of this proceeding and future potential investigations, pilot programs, and targeted deployments, and we address the regulatory framework that exists and that will evolve for the review and approval of pilot programs to examine emerging decarbonization technologies.

2. Summary of Comments

Commenters generally agree with the recommendation that the Department should streamline its review of pilot opportunities to facilitate more timely evaluation and deployment of electrification and decarbonized technologies (see, e.g., DOER Initial Comments at 16; CLF Initial Comments at 60; Acadia Center Initial Comments at 25). However, commenters disagree about which technologies, fuels, and end uses merit ratepayer-funded R&D (see, e.g., Attorney General Final Comments at 11-12; AIM Comments at 2; RMI Final Comments at 4; EDF Initial Comments at 1-3). To that end, the

Attorney General urges the Department to acknowledge the technical uncertainty of decarbonizing the building heating sector, calling for a framework that provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates (Attorney General Final Comments at 3-4).

Several commenters express support for the LDCs' approved networked geothermal pilots, arguing for the accelerated deployment of this technology (see, e.g., Sierra Club Final Comments at 11-12; CLF Initial Comments at 12; Climate Action Now Western Mass Comments at 2 (May 5, 2022); Mothers Out Front Massachusetts Comments at 1, 4 (May 2, 2022)). The Attorney General calls on the Department to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies to examine possible regulation and ownership frameworks as the Department continues to learn about the costs, feasibility, and scalability of networked geothermal (Attorney General Initial Comments at 45-46). Similarly, HEET proposes a framework for the evolution of LDCs into thermal utilities, positing that pilots involving 100 customers or fewer could be approved by the Department within a month of filing (HEET Comments at 17, 22-32). The LDCs state that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

Numerous commenters call for R&D into other types of targeted electrification, including decommissioning of the gas system, that may demonstrate cost savings (see, e.g., CLF Initial Comments at 9, 55; DOER Final Comments at 16-17). The Attorney General calls for the adoption of comprehensive geographic distribution system and customer mapping,[52] in addition to an investment alternatives calculator to assist in reviewing traditional gas system capital investments (Attorney General Initial Comments at 22-24, 33-35; Attorney General Final Comments at 10-11). Similarly, DOER recommends that the Department require the LDCs to complete geographic mapping and marginal cost analyses before moving forward with any additional R&D proposals so that the LDCs can use these results in determining the appropriateness of any such projects (DOER Initial Comments at 14-15; DOER Final Comments at 7-10, 19-20).

Numerous commenters object to LDCs piloting alternative fuel blends (i.e., RNG, hydrogen, SNG) into their distribution systems, raising concerns about safety, affordability, GHG emissions, and leakage (see, e.g., Attorney General Initial Comments at 11-14; Acadia Center Initial Comments at 21; Sierra Club Initial Comments at 17; Massachusetts Medical Society Comments at 1-2). Other commenters acknowledge that alternative fuels may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in various hard-to-electrify end uses including certain industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments[53] at 1; Medical Area Total Energy Plant Comments at 1 (July 28, 2022)). The Attorney General

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[52] The Department further discusses geographically planned approaches and gas/electric coordination topics below in Section VI.D and Section VI.G.

[53] Comments of the Rev. Mariama White-Hammond, Chief of Environment, Energy, and Open Space, City of Boston (May 5, 2022).

recommends that any investment in unproven technologies such as RNG and hydrogen be viewed as imprudent today with the associated costs being borne entirely by utility shareholders (Attorney General Initial Comments at 32-33). Regarding proposals for new technologies or fuels, DOER argues that the LDCs must identify "go/no go benchmarks," including when to abandon a project or program if the results show that longer-term implementation would not be cost effective for ratepayers and/or achieve net-zero emissions in the most cost-effective manner (DOER Final Comments at 12).

3. Analysis and Conclusions

a. Introduction

Demonstration projects or pilots are well-established and evaluated vehicles for the introduction of emerging technologies into the existing framework of broadly deployed programs such as energy efficiency. In Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, updating its energy efficiency guidelines, the Department compiled directives from recent orders that addressed the appropriate process and standard of review for approval and changes to demonstration project proposals. D.P.U. 20-150-A at 22. The Department described a demonstration project as "a relatively small, self-contained endeavor, such as a pilot, that may transition to a core initiative or program," and further clarified demonstration project evaluation, budgetary, and cost-effectiveness considerations. D.P.U. 20-150-A at 24-25; Guidelines § 3.9.[54]

In this proceeding, numerous commenters agree that the Department should develop additional guidance for its review and approval of pilot projects and R&D programs in an effort to study and deploy innovative electrification and decarbonized technologies (see, e.g., Regulatory Designs Report at 27-30; DOER Initial Comments at 16; Attorney General Initial Comments at 24, 33). The Department strives to foster the innovation necessary to ensure the safe and reliable delivery of low-carbon energy in an equitable manner; at the same time, the Department must consider the potential customer bill impacts of any additional cost recovery mechanisms for pilots, as ratepayers in the Commonwealth already experience significant energy supply and programming costs. See, e.g., 2022-2024 Three-Year Plans Order at 220, 223. The Department maintains that pilots are valuable because they are small in scale and allow for the collection of distinct data and insights that will advance knowledge in a specific field. See, e.g., D.P.U. 21-24, at 26; Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 10-12 (2017).

The Regulatory Designs Report recommends that the LDCs pilot and deploy four specific technologies (Regulatory Designs Report at 27-29). As discussed below, the

54 The Department defines a demonstration project as a hard-to-measure offering, including pilots, limited in term and scope designed to provide the information required to assess its potential for measurable, cost-effective savings and benefits that can be scaled to be included in programs. Guidelines § 2.3. Demonstration projects are hard-to-measure offerings initially but are anticipated to have measurable savings and benefits at scale. Guidelines § 3.9.1.1.

Department welcomes networked geothermal and other targeted electrification technologies[55] in particular as promising decarbonization strategies and will require each LDC to identify pertinent demonstration projects in each of its service territories. In contrast, the Department is uncertain about the viability of hybrid heating and hydrogen technologies and their potential as economical long-term solutions for ratepayers, for the reasons we discuss below.

b. Hybrid Heating Systems

The Regulatory Designs Report recommends investigation into the optimal operation of hybrid heating systems, in support of both the gas and electric distribution systems (Regulatory Designs Report at 28). Specifically, the Consultants recommend further investigation of certain design elements for hybrid heating systems, such as the installation of integrated controls (Regulatory Designs Report at 28).[56]

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55 The Department emphasizes that pilot projects, including those for networked geothermal and other targeted electrification technologies, funded by gas ratepayers must benefit those ratepayers and not constitute cross-subsidization. See D.P.U. 19-120, at 147-148 (networked geothermal project must be designed in a manner to provide direct benefits to ratepayers whether through participation or in a manner that will generate findings to inform the scalability of networked geothermal for its existing gas customers).

56 The Consultants note that during the 2019-2021 Three-Year Plan term, program administrators created initial integrated controls specifications and requirements to ensure that heat pumps installed to augment existing systems operate efficiently, and that additional studies were proposed in the 2022-2024 Three-Year Plan term (Regulatory Designs Report at 28). "Program Administrators" are the LDCs as well as electric distribution companies and approved municipal aggregators who develop and administer energy efficiency programs under the Green Communities Act. St. 2008, c. 169. D.P.U. 20-150-A at 1.

Several commenters express skepticism about hybrid heating systems, urging the Department to reject the hybrid electrification scenario completely (see, e.g., Attorney General Technical Comments at 3, 19, 21; Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5).[57] As mentioned above, the Attorney General argues that the Pathways Report's promotion of a hybrid electrification pathway rests on unsound and unproven assumptions, and that the benefits of hybrid electrification on electric infrastructure additions can be attained by focusing on building electrification in the near term (Attorney General Technical Comments at 6-21).

The LDCs maintain that hybrid electrification is a practical and relatively low-challenge strategy and opportunity to achieve the Commonwealth's decarbonization objectives (LDC Joint Comments at 70). The LDCs argue that hybrid electrification technologies: (1) reduce the need for electric system build out; (2) mitigate costs and winter peaking; and (3) provide energy security benefits as a cold-climate backup system (LDC Joint Comments at 70-75). Other commenters argue that a hybrid electrification approach to decarbonization preserves optionality and elements of customer choice as renewable generation increasingly comes online (see, e.g., AIM Comments at 2; Shell USA, Inc.

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57 As noted above, Section 77 of the 2022 Clean Energy Act explicitly prohibits the Department from approving any company-specific plan pursuant to D.P.U. 20-80 prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, at present, the Department will not endorse or reject any specific pathway or space heating technology.

Comments at 4-5; Tufts Medicine Lowell General Hospital Comments at 1; Lahey Hospital and Medical Center Comments at 1; SFE Energy Comments at 3).

The Department cannot reject or prohibit hybrid heating systems as an option for customers. It is, after all, the customer who chooses the type of heating system to install in the home or building. The Department shares the concerns expressed by numerous commenters, however, that a customer's retention of a gas furnace or boiler to serve exclusively as a cold-climate backup may not be necessary.[58] In the short term, hybrid heating could be used to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). In the long term, however, it will be impractical to maintain the gas distribution system solely for backup furnaces in cold weather. The Department will therefore not approve the use of additional ratepayer dollars for hybrid heating system pilots and, as stated below, we expect LDCs to focus on targeted electrification and—pending the outcome of current pilots—networked geothermal projects to meet the long-term climate targets of the Commonwealth.

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58 The Department notes that research priorities for the LDCs as Program Administrators of the 2022-2024 Energy Efficiency Plan include studying residential hybrid heat pump controls, optimization, and metering impacts, in addition to requiring integrated controls for certain residential and income-eligible applications (See D.P.U. 21-120 through D.P.U. 21-129, Exh. 1, at 77; Exh. 1, App. H at 21, 57-60).

Nevertheless, the Department must ensure that the information contractors relay to customers who are deciding between hybrid and full-electrification technologies is both informative and correct. Therefore, the Department will require the LDCs to report on hybrid heating switchover practices in their first Climate Compliance Plan filings. This first Climate Compliance Plan report must include a discussion of the technical resources provided to contractors in the Mass Save heat pump installer network such as heat pump capacity and temperature point heuristics, and address any service area specific guidance that differs from cold-climate sizing and design trainings offered by common manufacturers. The Department fully expects that the LDCs as Program Administrators will continue to explore hybrid heat pump shared benefit and incentive structures, particularly related to LMI participants.

c. Renewable Hydrogen and RNG

The Regulatory Designs Report recommends that the LDCs pursue pilot opportunities to investigate the extent to which hydrogen and RNG can be blended safely into the LDC distribution system without the need for customer equipment or pipeline upgrades (Regulatory Designs Report at 28). The Consultants further note R&D opportunities related to the commercialization of synthetic gases and recommend investigating certified natural gas which may have reduced upstream emissions from the production of gas (Regulatory Designs Report at 28-29).[59]

59 The Department discusses synthetic and certified gas commodity above in Section VI.C.

Numerous commenters express concern with potential emissions and leakage issues associated with hydrogen blending, with the Attorney General arguing for all investments in hydrogen to be viewed as imprudent, and borne entirely by shareholders (see, e.g., Attorney General Initial Comments at 32-33; EDF Initial Comments at 1-3). Other commenters note that alternative fuels such as hydrogen may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in certain hard-to-electrify end uses such as industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments at 1; Medical Area Total Energy Plant Comments at 1). The LDCs acknowledge that the GHG effects of leaked, non-combusted hydrogen are not well understood, and that very few studies are available on its global warming potential (LDC Joint Comments at 56, citing Pathways Report at 113).

The Department agrees that significant research is necessary before hydrogen feasibly could be injected into an LDC's distribution system. The Department notes that the states of New York, New Jersey, Maine, Rhode Island, Connecticut, and Vermont along with the Commonwealth of Massachusetts announced the submission of a proposal for a Northeast Regional Clean Hydrogen Hub[60] to the U.S. Department of Energy ("DOE") to compete for a $1.25 billion share of the $8 billion in federal hydrogen hub funding available as part of the Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 (2021). In an announcement on October 13, 2023, DOE announced the first regional hydrogen hubs and the Northeast

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60 See https://www.masscec.com/press/seven-states-northeast-regional-clean-hydrogen-hub-announce-submission-362-billion-proposal (last visited November 29, 2023).

Hydrogen Hub was not selected for funding.[61] The Department is optimistic that future funding opportunities may allow for the exploration of hydrogen R&D in the region without requiring additional ratepayer funds.

The Department also acknowledges, however, that there may be certain end uses, such as high-temperature industrial processes, that require a combustible molecule of a lower GHG emissions profile. In the short term, the Department will entertain hydrogen demonstration proposals for targeted end uses. Any proposals for hydrogen or RNG pilots, however, should include cost-effectiveness screening, and in the absence of cost-effectiveness screening, an appropriate analysis must support the potential of the proposal to deliver net benefits in the future. Guidelines § 3.9. Further, hydrogen and RNG demonstration project proposals must thoroughly explain how the targeted application is "hard to decarbonize," in addition to explaining electrification alternatives and alignment with the GWSA and the 2021 Climate Act. Further, RNG and hydrogen pilot proposals must take into consideration environmental justice populations and ensure that any such projects do not contribute to a decline of indoor air quality.

d. Networked Geothermal

Networked geothermal technology connects multiple, energy-efficient ground-source heat pumps ("GSHPs") to a loop system designed to provide heating and cooling to multiple buildings in a geographic area. The Department has found that: (1) geothermal networks

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61 See https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving (last visited November 29, 2023).

have the potential to significantly reduce GHG emissions; and (2) geothermal demonstration projects designed to test the effectiveness and scalability of utility-owned geothermal networks have the potential to reduce current barriers to widespread adoption in furtherance of the Commonwealth's climate policies. D.P.U. 19-120, at 139.

Several commenters express support for networked geothermal technologies and their expedited deployment (see, e.g., Attorney General Initial Comments at 45-46; DOER Final Comments at 9, 15-16). The LDCs acknowledge that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

The Department commends the LDCs for exploring an innovative technology that has the potential to reduce GHG emissions and barriers to widespread deployment of clean heating technologies in furtherance of the Commonwealth's climate laws and policies. The Department notes the substantial progress in the construction of the Commonwealth's first utility-owned networked geothermal demonstration project in Framingham, with NSTAR Gas planning for the loop to be in operation prior to the 2023 heating season. See NSTAR Gas Company, D.P.U. 23-86, Exh. EVER-ANB/NLB-1, at 11.

Regarding the Attorney General's request to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies, the Department concludes that opening an investigation at this time is premature. The Department shares the optimism expressed by stakeholders concerning the operation and management of the approved networked geothermal demonstrations, and eagerly awaits successful evaluation data concerning their costs, feasibility, and potential scalability.[62] Depending upon the results of that evaluation, the Department can be expected to move expeditiously to develop broader guidance for networked geothermal, which may require specific performance metrics and strategies to target benefits toward environmental justice populations.

e. Targeted Electrification

Several commenters support additional targeted electrification demonstration projects, in which a participant would disconnect from the gas distribution system and fully electrify space heating and appliance loads (see, e.g., CLF Initial Comments at 9; RMI Final Comments at 3). To that end, numerous commenters recommend that the LDCs complete comprehensive geographic system and customer mapping, in addition to marginal cost analyses to explore cost-effective alternatives to traditional gas investment (see, e.g., Attorney General Final Comments at 14-15; DOER Initial Comments at 14-15).[63]

The LDCs respond to this proposition by citing several factors that require evaluation before targeted electrification is undertaken on parts of their systems (LDC Joint Comments at 68). The LDCs indicate, for example, that removing gas service from certain parts of

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62 In addition, the Department has approved a settlement agreement in Eversource Energy/Bay State Gas Company, D.P.U. 20-59/19-140/19-141 at 61 (2020), that provided funding for the Attorney General and DOER to administer a geothermal microgrid pilot in the Merrimack Valley.

63 The Department further discusses comprehensive geographic distribution system and customer mapping below in Section VI.G below.

their systems may result in operational concerns regarding system pressures and flows elsewhere on their systems (LDC Joint Comments at 68). The LDCs also argue that decommissioning the gas distribution system would require greater education efforts, as removing gas service as an option for any of a customer's building needs will affect the viability of proposed targeted electrification options (LDC Joint Comments at 68). Generally, the LDCs raise concerns about the process, standards, and policies surrounding targeted electrification, while ensuring the safety and reliability of customers who choose to remain on the system (LDC Joint Comments at 68-69).

The Department is optimistic that targeted electrification through decommissioning parts of the gas system may serve as a promising approach to reaching the Commonwealth's GHG emissions targets; the Department also recognizes, however, that there are several operational constraints and unknowns as raised by the LDCs. To better understand these opportunities and constraints, the Department directs each LDC to work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory. Each LDC, in coordination with the applicable electric distribution company, shall propose at least one demonstration project in its service territory for decommissioning an area of its system through targeted electrification. The LDC should target a portion of its system that suffers from pressure/reliability issues, leak-prone pipe, and/or that targets environmental justice populations that have borne the burden of hosting energy infrastructure. The Department expects the LDCs to engage with elected and appointed officials in the community, community-based organizations that work on energy, environment, labor, or ending poverty, and other interested residents. The Department directs each LDC to file its project proposal by March 1, 2026, for inclusion in its 2030 Climate Compliance Plan, working with its relevant electric distribution company and Program Administrator as necessary.[64]

f. Demonstration Project Process

In reviewing a proposed demonstration project, the Department considers the: (1) reasonableness of the size, scope, and scale of the proposed project in relation to the likely benefits to be achieved; (2) adequacy of the evaluation plan; (3) extent to which there is appropriate coordination among Program Administrators; and (4) bill impacts to customers, among other things. Guidelines § 3.9.1. Demonstration projects are not required to be cost effective at the initial testing and evaluation stage; however, an evaluation report at a demonstration project's conclusion requires detailed analyses of actual project costs and benefits, in addition to projected costs and benefits were the project to be delivered as a program at scale. Guidelines §§ 3.9.1.1, 3.9.2. In absence of cost-effectiveness screening,

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64 The Department has found that, while pursuing energy and demand savings through strategic electrification, the Program Administrators must seek to reduce GHG emissions and minimize ratepayer costs. 2022-2024 Three-Year Plans Order at 84. Splitting incentives between gas and electric Program Administrators may mitigate bill impacts and produce a more equitable sharing of costs and benefits between gas and electric ratepayers. The Department notes that Program Administrators already are required to address fully how they considered a split incentive for both large traditional custom projects and large strategic electrification projects that involve offsetting natural gas consumption in its three-year energy efficiency plan, term report, and any applicable mid-term modification proposals. Liberty Utilities (New England Natural Gas Company Corp., D.P.U. 22-94, at 14 (2022).

detailed program descriptions and appropriate analysis must support the potential of a demonstration project to deliver net benefits in the future. Guidelines § 3.9.1.2.

The Department recognizes that both geothermal demonstration projects that have come before us required multiple proceedings, such as separate proposal, implementation, and cost-recovery filings, in addition to project-level evaluation studies.[65] See, e.g., Boston Gas Company, D.P.U. 20-120, Interlocutory Order on Proposed Demonstration Projects (December 11, 2020); NSTAR Gas Company, D.P.U. 21-53, Order on Phase I NSTAR Gas Company's Implementation Plan (January 4, 2022); NSTAR Gas Company, D.P.U. 22-125, Stamp Approval (December 5, 2022). Inasmuch as the Department had not reviewed a geothermal network proposal prior to 2020, however, such a proposal was considered a matter of first impression. The Department determined that these additional proceedings were therefore necessary to protect participating consumers, set the appropriate budgets, and maintain general oversight as the LDCs use ratepayer dollars to explore innovative solutions in support of Massachusetts' GHG emissions reductions targets. D.P.U. 19-120, at 138, 141, 148-149, 154; D.P.U. 21-53, at 8-9.

The Department has general supervisory authority over gas and electric companies, and must make all necessary examination and inquiries to keep itself informed as to the

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65 The Department acknowledges that multiple proceedings may serve as a barrier to meaningful engagement and participation by the public, and, to that end, the Department opened an investigation into procedures for enhancing public awareness of and participation in its proceedings. Notice of Inquiry by the Department of Public Utilities on its own Motion into Procedures for Enhancing Public Awareness of and Participation in its Proceedings, D.P.U. 21-50 (2021).

condition of the respective properties owned by such corporations, and the manner in which they are conducted with reference to the safety and convenience of the public. G.L. c. 164, § 76. The Department anticipates that the desired streamlining will occur as demonstration projects in support of the Commonwealth's GHG emissions reductions targets become more routine and as the LDCs understand what is expected of them in meeting the Department's standard of review.

Accordingly, the Department concludes that no further "streamlining" of its demonstration project review is required at this time, and that the LDCs have received sufficient guidance and cost-recovery avenues for researching and deploying innovative electrification and decarbonization technologies. The Department fully recognizes the financial and technological uncertainties that LDCs face in reaching the Commonwealth's mandated decarbonization targets; to minimize ratepayer costs, however, we continue to require that innovative technologies be rooted in cost-effectiveness and be offered in a cost-efficient manner.

Any demonstration project proposals related to innovative technologies must include detailed implementation plans and terms and conditions that are acceptable to and protective of participants. Each LDC seeking to demonstrate a new technology must propose novel objectives that will reasonably result in quantifiable GHG emissions reductions, and each LDC will be required to provide updates in its Climate Compliance Plan reports. As circumstances change, the Department may consider an alternative framework to incentivize the deployment of decarbonization technologies, as necessary.

E. Manage Gas Embedded Infrastructure Investments and Cost Recovery

1. Introduction and Summary

As discussed above in Section V.A, most of the pathways modeled predict declines in the number of LDC customers and system utilization over time (Regulatory Designs Report at 31-32). The Consultants raise two main concerns surrounding the issue of declining customers and throughput, namely the resulting higher costs for customers remaining on the natural gas system, and a mismatch between how infrastructure costs are currently recovered and the predicted system utilization (Regulatory Designs Report at 31-32). To mitigate the potential impacts associated with the recovery of embedded infrastructure costs and declining system usage, the Consultants recommend finding ways to minimize or avoid gas infrastructure investments where possible, pre-approval of non-GSEP investments, revisions to existing line extension policies, and accelerated depreciation (Regulatory Designs Report at 32-40).

a. Minimize Capital Investments

The Consultants recommend that the Department and LDCs develop a framework to examine opportunities to minimize or avoid gas infrastructure projects, while continuing to maintain safe and reliable service (Regulatory Designs Report at 32-33). The Regulatory Designs Report encourages geographically targeted electrification where possible as a way to address embedded infrastructure cost issues, as well as investigating various NPAs to replace non-cathodically protected steel, cast-iron, and wrought iron, and other aged pipe with new pipe (Regulatory Designs Report at 33). The Consultants acknowledge that these options are not without barriers, as targeted electrification requires all customers in an area to agree to terminate gas service and switch to electric service, and there are costs associated with switching (Regulatory Designs Report at 33). NPAs discussed include energy efficiency measures, demand response solutions, electrification, and networked geothermal systems (Regulatory Designs Report at 33-34).

b. Pre-Approval

The Consultants recommend the Department establish a process to review and pre-approve LDC capital investment plans relating to non-GSEP investments (Regulatory Designs Report at 34). They suggest conducting holistic, long-term capital planning that aligns safety and reliability investments with the Commonwealth's decarbonization targets (Regulatory Designs Report at 34). The Consultants propose reviewing LDC capital plans every three years—similar to the review process for energy efficiency plans—and that the process should evaluate changes in forecasted demand driven by decarbonization goals (Regulatory Designs Report at 34).

c. Line Extensions

Another recommendation for managing the concerns around embedded infrastructure is to revise the standards associated with line extensions and investments to serve new customers (Regulatory Designs Report at 34-36). The Consultants note that currently the standard for serving new customers is that existing customers must not subsidize the cost to serve new customers, and that to the extent the incremental revenues of the customer addition are not equal to or greater than the associated costs, the difference must be paid by the customer in the form of a CIAC (Regulatory Design Report at 36). The Consultants identify four potential changes to the current line extension policy: (1) shortening the investment payback period; (2) reducing customer revenues supporting the new investments; (3) increasing the target rate of return on the investments; and (4) requiring customers to guarantee the revenues supporting the incremental costs (Regulatory Designs Report at 36).

d. Accelerated Depreciation

Rather than the current practice of utilizing straight-line depreciation, the Consultants recommend accelerated forms of depreciation, such as the Units of Production method or implementing shorter service lives, to better align the recovery of infrastructure costs with the anticipated utilization and anticipated customer migration (Regulatory Designs Report at 37-40). The Consultants suggest that while accelerated forms of depreciation increase costs in the short term, the associated depreciation costs should remain stable compared to continued use of the straight-line method, which will result in increased future costs if system utilization declines (Regulatory Designs Report at 37-38). Accelerated deprecation is presented as not only a means of mitigating affordability and equity concerns, but also a way to mitigate concerns related to unrecovered rate base as customers leave the gas system by recovering costs in an accelerated fashion (Regulatory Designs Report at 38-39).

2. Summary of Comments

A number of commenters specifically argue that line extensions and new customer additions should cease as soon as possible, citing health concerns, the potential for stranded assets, and the ability to achieve net-zero emissions (see, e.g., McCord Comments at 3

(May 6, 2022); Muzzy Comments at 1 (May 6, 2022) ("Muzzy Comments"); PLAN Final Comments at 6; RMI Initial Comments at 12-13; Robinson Comments at 1 (May 4, 2022)). Other commenters express general concerns regarding stranded assets associated with increased capital investments, and some urge a transition away from investments in fossil fuels (see, e.g., Archbald Comments at 1 (May 6, 2022); Armstrong Comments at 1 (May 4, 2022); Boston Common Asset Management Comments at 2 (May 6, 2022); Burdick Comments at 1 (May 6, 2022); C. Rose Comments at 1 (May 4, 2022); Royce Comments at 1 (May 2, 2022)). Several commenters support implementing opportunities to minimize or avoid gas infrastructure projects generally (see, e.g., Acadia Center Initial Comments at 24); CLF Initial Comments at 9).

LEAN contends that furthering capital investments and any proposals to accelerate cost recovery will only increase financial risks and create affordability issues for low-income customers in particular (LEAN Initial Comments at 10, 18). Alternatively, the Attorney General suggests that the Department conduct a review of existing tariff provisions and line extension policies, as there is no current uniform model or costing matrix to assess the cost-benefit analysis of line extensions (Attorney General Initial Comments at 32); Attorney General Final Comments at 16). More specifically, the Attorney General states the Department should determine whether the current CIAC model is consistent with state policies and goals, reflects anticipated investment recovery, and results in mostly free extensions for new customers (Attorney General Initial Comments at 32). The LDCs acknowledge that not all utilities handle line extensions in a uniform way and do not oppose a collaborative review of the current models or the development of a common framework as proposed by the Attorney General (LDC Joint Comments at 93).

In addition to the suggested review of CIAC models and line extension policies, the Attorney General recommends that the Department retain consultants or work with utilities to develop an "investment alternatives calculator" that would review and compare the expected costs of new gas system investments with the short- and long-term costs of alternative solutions (Attorney General Initial Comments at 33-35; Attorney General Final Comments at 11). The Attorney General contends that a properly designed investment alternatives calculator would provide a set of prescribed assumptions for the cost of carbon, a range of values for the cost of gas commodity, the cost of avoided GHG emissions, and the cost of alternative technologies (Attorney General Initial Comments at 33-34)

Regarding depreciation, Acadia Center, CLF, and others argue that accelerated depreciation is worth investigating, and DOER contends that a geographic marginal cost analysis to address decommissioning plans should be required before accelerated depreciation is allowed (see, e.g., Acadia Center Initial Comments at 24; CLF Initial Comments at 54; DOER Initial Comments at 17; RMI Initial Comments at 13). CLF also suggests that investigations into any depreciation changes should begin promptly, as any delays could increase the risk of rate shock when changes are implemented, and that depreciation rates should reflect the utilization of different assets with different lifetimes (CLF Initial Comments at 49, 53).

The Attorney General asserts that accelerated depreciation inappropriately shifts market and climate policy risk from utilities to ratepayers while increasing the cost of gas service (Attorney General Initial Comments at 35-36). She suggests it is unrealistic for utilities to continue to invest in gas infrastructure without regard to market risks and decarbonization goals, and that the Department may choose to treat future infrastructure investments differently from those made historically (Attorney General Initial Comments at 36). The Attorney General contends the Department should order LDCs to file information on the magnitude of potential stranded costs and work to establish clear cost recovery timelines or guidelines to balance the costs and responsibilities of possible stranded assets (Attorney General Initial Comments at 35-37; Attorney General Final Comments at 16). The Town of Hopkinton opposes the adoption of accelerated depreciation, arguing that it shifts cost recovery to taxpayers from the LDCs and ratepayers (Town of Hopkinton Comments at 3-4 (May 6, 2022)). The LDCs disagree with the Attorney General's assessment regarding the shifting of risks, and instead argue that accelerated depreciation addresses affordability concerns for current and future customers while maintaining a safe and reliable system (LDC Joint Comments at 86). The LDCs argue that they must continue to make investments to maintain the gas system, and that the regulatory compact entitles utilities to an opportunity to earn a reasonable return on, and a return of, their prudent investments (LDC Joint Comments at 87). The LDCs also disagree with DOER's assertion that consideration of accelerated depreciation should be delayed until the completion of a marginal cost analysis addressing decommissioning plans, arguing that it would be subject to significant uncertainty and complexities (LDC Joint Comments at 87-88).

3. Analysis and Conclusions

a. Pre-Approval and Capital Investments

The Regulatory Designs Report recommends that the Department review and pre-approve certain future LDC capital investments as part of the reporting and planning process going forward in order to continue providing safe and reliable gas service (Regulatory Designs Report at 46). In the instant proceeding, the Department is not persuaded that pre-approval of investments is appropriate at this time. We observe that there are extensive federal and state regulations intended to ensure the safe maintenance and operation of the natural gas pipeline system, which include safety standards and mandated program improvements. The Department will not interfere with the mandates of the federal and state regulations. See, e.g., 49 C.F.R. §§ 192.907, 911, 1005, 1007; 220 CMR 101.00. The Department does, however, recognize that achieving state climate change goals necessarily requires the minimization of stranded investments to the extent possible. The Consultants recommend encouraging NPAs as alternatives to replacing aged pipes and/or installing new mains. The Attorney General argues that the Department should adopt a robust alternatives analysis or an "investment alternatives calculator" to ensure that any investments made represent the best alternative available at the time (Attorney General Initial Comments at 33; Attorney General Final Comments at 11). The Department agrees that consideration of NPAs will be an essential part of the regulatory landscape, and that companies should begin examining opportunities to minimize investments that may contribute to future stranded costs. As described in Section III above, the recoverability of additional investment in natural gas infrastructure will require an analysis of whether such investments are consistent with state emissions reduction targets and the thorough evaluation of NPAs. As part of any future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive in order to receive full cost recovery.[66]

b. Line Extensions

As discussed in Section III, the Commonwealth's climate laws, which include a 2050 GHG emissions reduction mandate and interim targets, require LDCs and the Department to move beyond a "business as usual" approach to system planning and expansion. Accordingly, the Department agrees with the Consultant and commentor suggestions that the standards for investments to serve new customers be examined and revised. The Attorney General specifically recommends that the Department address the standard for line extensions, along with other ratemaking policies, as part of a gas ratemaking regulatory reform in a separate proceeding or working group (Attorney General Final

66 The Attorney General suggests the use of a "investment alternatives calculator" to evaluate NPAs. The Department agrees that stakeholders should have the opportunity to review not only individual NPA analysis but the underlying assumptions and inputs. The Department therefore directs that in conducting the cost-benefit analysis underlying the consideration and evaluation of NPAs, the LDCs consult with stakeholders prior to submitting an NPA analysis for Department review and adjudication.

Comments at 16). The LDCs express a willingness to develop collaboratively a common framework for evaluating new service connections and a review of existing CIAC and internal rate of return ("IRR") models (LDC Joint Comments at 92-93). The Department directs all LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions.

The Department recognizes that certain statutory and legislative changes may be necessary going forward. In NSTAR Gas Company, D.P.U. 22-107 (2022), in the context of a proposed extension of natural gas service to the Town of Douglas, several parties and participants expressed concern that Section 3 of the Gas Leaks Act, which mandates that the Department review and approve proposals designed to increase the availability, affordability, and feasibility of natural gas service for new customers, is inconsistent with the Commonwealth's GHG emissions reduction targets and climate policies. D.P.U. 22-107, at 6-9, 12. Section 3 was enacted by the Legislature in 2014. D.P.U. 19-120, at 464. Prior to any approval and implementation of a program proposed under Section 3, the Department must review the company's determination that a main or service extension is economically feasible and review the gas company's CIAC policy and methodology. St. 2014, c. 149,

§ 3(a); D.P.U. 19-120, at 456. In D.P.U. 22-107, the Department found that the state's recent climate legislation neither repealed nor amended Section 3; however, we recognize the inherent conflict between the express goals of these statutes given that Section 3 encourages investments in new main and service extensions and increased use of natural gas, while climate legislation mandates a reduction in GHG emissions. See D.P.U. 19-120, at 464. For the Department to pursue fully its mandate to prioritize reductions in GHG emissions along with safety, security, reliability of service, affordability, and equity as directed by the Legislature in the 2021 Climate Act, we recommend that the Legislature repeal Section 3 of the Gas Leaks Act to eliminate any potential conflict of laws.

With respect to line extensions and applications specifically pursuant to G.L. c. 164, Section 30,[67] the Department determines whether a proposal is reasonable. As discussed in D.P.U. 22-107, we have found this includes the overarching consideration of the public interest, defined generally as requiring that there be no adverse impacts on existing natural gas customers. D.P.U. 22-107, at 3-4. In reviewing future applications, the Department will examine the public interest in the context of our broader climate mandates. In doing so,

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67 The Department reviews petitions for authorization to expand a gas distribution company's service territory pursuant to G.L. c. 164, § 30, which states:

> The [D]epartment may, after notice and a public hearing, authorize a gas or electric company to carry on its business in any town in the commonwealth other than the town named in its agreement of association or charter, subject to sections eighty-six to eighty-eight, inclusive, and it may purchase, hold and convey real and personal estate in such other town necessary for carrying on its business therein.

we note that Section 30 does not require that the Department grant petitions in those circumstances where such a grant would not adversely impact existing customers. See D.P.U. 22-107, at 4. We also note that in D.P.U. 22-107, the Department found that the company had demonstrated that an alternative electrification approach was economically unviable, and that the expansion of services into the Town of Douglas was reasonable and consistent with the public interest. D.P.U. 22-107, at 15. While Section 30 does not expressly require a company to evaluate alternatives to expanding its gas system, going forward the Department will take the evaluation of alternatives into consideration along with any impact on achieving the state's climate targets. D.P.U. 22-107, at 15. Finally, although the adjudication of a specific standard of review is outside the scope of this proceeding, the Department anticipates that its consideration of a petition pursuant to Section 30 will presume a requirement of consistency with an LDC's Climate Compliance Plan, as discussed in Section VI.G.

c. Accelerated Depreciation

There is general consensus among the LDCs and stakeholders that the issue of depreciation and stranded assets must be examined. While stakeholders differ as to the exact approach to deal with the issue, the Department agrees that the matter is important and must be investigated. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments. As part of this review, the LDCs must identify the impacts of accelerated depreciation proposals and identify potential alternatives to accelerated depreciation.

The Consultants and LDCs specifically reference the "Units of Production" method of accelerated depreciation as a way of aligning cost recovery of capital investments with system utilization, noting that it is a method recognized by the National Association of Regulatory Utility Commissioners ("NARUC"), as well as the option of implementing shorter asset service lives (Regulatory Designs Report at 38). The Department notes there are various options to consider with respect to accelerated depreciation, and the LDCs should not limit their review to any one method such as the Units of Production method, as each has its own inherent benefits and limitations (see, e.g., Regulatory Designs Report at 38; NARUC Depreciation Manual at 52-53; 57-61). Accelerated depreciation methods currently are not used for regulatory purposes, with the straight-line method primarily utilized in utility depreciation studies (NARUC Depreciation Manual at 61). The Department previously has recognized, however, that there is a fundamental transition underway in the gas industry in Massachusetts, and further investigation of cost recovery of existing infrastructure investment is required. The goal of the review should be not only assessing the magnitude of stranded costs, but also to investigate ways to address cost recovery while balancing ratepayer and shareholder risk going forward in a way that adequately reflects system costs, shareholder awareness of risk, and realistic expectations of the future, while addressing customer affordability and equity concerns.

F. Evaluate and Enable Customer Affordability

1. Introduction and Summary

The fifth regulatory recommendation focuses on evaluating and enabling customer affordability as customers transition away from reliance on the gas system to decarbonized technologies. The Consultants caution that each of the identified decarbonization pathways raise cost considerations for customers as well as associated equity challenges, which will require regulatory and policy interventions to mitigate impacts on customers (Regulatory Designs Report at 40). In particular, the Consultants explain that given the magnitude of potential cost impacts, and the rate and equity implications associated with progress toward electrification, there is a need to expand the scope of the current cost recovery mechanisms for LDCs (Regulatory Designs Report at 41). The Consultants therefore recommend a specific set of regulatory designs and policy changes to address these concerns, which we discuss below (Pathways Report at 100-108; Regulatory Designs Report at 40-45).

a. Cost and Equity Implications of the Pathways

The Consultants highlight that the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity are a significant barrier for customers to migrate off the gas system (Pathways Report at 105-106). The Consultants further state that when a growing number of customers transition off the gas system, customers who remain on the system will experience increasing energy costs that they must absorb (Regulatory Designs Report at 40; Pathways Report at 106). Absent regulatory changes, the Consultants conclude the remaining customers will see higher rates due to varying increases in commodity or delivery costs[68] (Regulatory Designs Report at 41). The Consultants maintain that by 2050, some of the higher electrification pathways may result in unrealistic costs imposed on customers from $30,000 to more than $70,000 per customer per year (Pathways Report at 107). Pathways with more moderate levels of electrification result in less significant cost shifting, yet still yield costs per customer expected to be 40 percent to 50 percent above the reference case by 2050 (Pathways Report at 107).

In addition to affordability challenges, the pathways present equity challenges, including cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers designated as environmental justice populations (Regulatory Designs Report at 40; Pathways Report at 106). The Consultants explain that customers who are unable to fund the high upfront costs of switching to decarbonized technology (especially non-migrating customers who qualify for low income-rates and those who are designated as environmental justice populations) or otherwise face challenges in adopting clean technologies (i.e., the hard-to-electrify commercial sector) are more likely to remain stranded on the gas system and shoulder the growing costs (Pathways Report at 29, 106-109). The Consultants state that

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68 According to the Consultants' projections, certain pathways that allow for higher continued gas system utilization (i.e., "Efficient Gas Equipment" and "Low Electrification") will experience increased commodity cost of renewable gas in the system, while others that allow for lower gas system utilization (i.e., "High Electrification") will see increases in delivery costs due to customers departing the gas system and leaving behind uncollected embedded gas infrastructure costs to be recovered over fewer customers and/or therms (Pathways Report at 101; Regulatory Designs Report at 41).

low-income customers remaining on the gas system likely will spend an increasingly higher share of their income on energy, from approximately seven percent to more than 15 percent in 2050 (Pathways Report at 101-102).

In addition, the Consultants caution that the pathways present various equity considerations with respect to existing infrastructure retirements, new energy infrastructure construction, and the decommissioning of LDC infrastructure, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of LDC infrastructure (Pathways Report at 108). The Consultants explain that policies will need to address and mitigate, to the extent possible, impacts on environmental justice and low-income populations associated with siting and construction of energy infrastructure as well as potential decommissioning of any LDC facilities. The Consultants state that these mitigation policies are particularly important for environmental justice populations, which generally are concentrated in communities already hosting energy infrastructure (Pathways Report at 108).

b. Recommended Regulatory and Policy Interventions

The Consultants propose to address affordability and equity concerns through a set of specific regulatory design recommendations, which focus on understanding and minimizing the impacts of decarbonization on customers (Regulatory Designs Report at 42). These regulatory design recommendations include identifying and quantifying transition costs, evaluating the impacts of transition costs on customers, and exploring alternative cost recovery mechanisms and securitization as methods for mitigating affordability issues

(Regulatory Designs Report at 42, 45). In addition, the Consultants suggest that policy interventions such as targeted incentives aimed at promoting a more equitable transition to clean technologies are warranted (Regulatory Designs Report at 20, Pathways Report at 108). Ultimately, the Consultants conclude that the magnitude and pace of electrification associated with a particular pathway will impact LDCs and the Department's ability to develop and implement regulatory policies that mitigate potential cost shifts and associated equity issues (Pathways Report at 108).

First, the Consultants recommend developing a framework to identity and quantify transition costs (i.e., uncollected costs from customers who have departed the gas system, costs associated with design and implementation of the regulatory reforms,[69] workforce transition costs, and costs associated with restructuring or realignment of gas supply portfolios) (Regulatory Designs Report at 42). The next step should be to evaluate the impact of those transition costs on customers under the various pathways (Regulatory Designs Report at 42).[70]

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69 These proposed regulatory reforms include geographically targeted electrification, non-pipeline solutions, coordinated planning efforts between electric and gas utilities, and accelerated depreciation (Regulatory Designs Report at 42).

70 The Consultants explain that under some pathways, such as 100 percent gas decommissioning, the transition costs grow quickly and have a substantial impact on customer rates much earlier in the decarbonization pathway, while under other pathways, such as hybrid electrification, the transition costs grow more slowly and have a substantial impact on rates later in the decarbonization pathway (Regulatory Designs Report at 42).

The Consultants next recommend mitigating transition costs by evaluating alternative approaches to cost recovery, such as charging customers leaving the gas system an exit fee or migration fee ("migration charge"),[71] and a statewide recovery mechanism through electric surcharges ("transition charge") (Regulatory Designs Report at 42). The first approach suggests a migration charge for customers leaving the gas system to cover costs that were incurred to serve them but not collected (Regulatory Designs Report at 42-43).[72] According to the Consultants, this would minimize the cost shift to customers remaining on the system as well as minimizing the potential for non-recovery of embedded costs (Regulatory Designs Report at 43). The second approach of charging transition charges seeks to align the benefits of decarbonization with the transition costs through sharing the transition costs more broadly with those who benefit from the transition (Regulatory Designs Report at 43). The Consultants acknowledge that the mechanism underlying this approach requires considerable review and evaluation, including its implications on LDC customers and, more broadly, on those who would pay for the transition costs, but they suggest that the process could start with establishing a fund and continue with attempts to identify other funding sources (Regulatory Designs Report at 43). The Consultants assert that the substantial transition costs

[71] The Consultants refer to this fee as a "migration fee," while some commenters refer to the charge as an "exit fee." The Department uses the term migration charge, which has the same meaning as migration fee and exit fee, and references the terms used by commenters when summarizing comments.

[72] The Consultants posit that this option likely would require legislative approval given the charge would be based on LDC costs charged to non-LDC customers (Regulatory Designs Report at 42).

associated with each pathway require a cost recovery mechanism consistent with the scope and scale of such costs (Regulatory Designs Report at 42).

The Consultants' final recommendation is to evaluate the use of securitization as a method to finance transition costs and lower a utility's borrowing costs, which, in turn, decreases the amount customers will have to repay, and allows both parties to benefit directly from the bond market (Regulatory Designs Report at 45).[73] The Consultants acknowledge that securitization poses the challenge of requiring a secure revenue stream, whereas the revenue stream under the decarbonization pathways is subject to significant uncertainty (Regulatory Designs Report at 45). The Consultants suggest that a possible, albeit untested, solution to this uncertainty would be through charges on both gas and electric bills (Regulatory Designs Report at 45).

In addition to the above set of regulatory design recommendations, the Consultants introduce a few policy interventions they claim are needed to address affordability and regulatory concerns. First, to address the burden of upfront capital costs of appliances, as well as the costs associated with decarbonization in the building sector (e.g., implementing building shell retrofits), the Consultants suggest that expanded policies aimed at providing additional customer incentives should be established (Pathways Report at 102, 106-107; App. 1, at 57).

[73] The Consultants state that securitization has been used in the utility industry to finance the recovery of extraordinary costs (e.g., wildfire mitigation costs in California, coal plant decommissioning costs in New Mexico, and storm costs in Texas), serving to minimize the impacts on customer rates (Regulatory Designs Report at 45).

Next, the Consultants suggest that a means of mitigating the unintended consequences of inequitable cost shifting is to provide incremental incentives to low-income and environmental justice populations to promote decarbonization (Pathways Report at 108). In addition, the Consultants suggest that incentives designed to benefit both landlords and renters would help address the current misalignment of interests between these parties, especially for pathways with higher levels of customer transitions (Pathways Report at 108). Further, the Consultants caution that the pathways present various equity issues related to both existing infrastructure retirements and new energy infrastructure construction, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of gas infrastructure (Pathways Report at 108). Importantly, environmental justice populations are generally over-represented in communities already hosting energy infrastructure (e.g., LDC on-system LNG and propane assets). Given that each pathway has a significant level of energy infrastructure construction, the Consultants suggest that policies will need to specifically address and mitigate the disproportionate impacts on environmental justice and low-income populations associated with siting and constructing energy infrastructure as well as the decommissioning any LDC facilities (Pathways Report at 108).

2. Summary of Comments

Several commentors expressed affordability concerns, particularly for LMI customers (see, e.g., Attorney General Initial Comments at 50; DOER Initial Comments at 15; LEAN Initial Comments at 18; NCLC Initial Comments at 32; HEET Comments at 7). Several stakeholders call for the prioritization of LMI customers to ensure an equitable transition and protect those customers from bearing the increased energy burden associated with electrification (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). Stakeholders generally agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., Acadia Center Initial Comments at 22; LEAN Initial Comments at 17). To that end, several commentors suggest that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., Attorney General Initial Comments at 52; DOER Initial Comments at 15; LEAN Initial Comments at 18).

The Attorney General argues that the current gas regulatory framework does not protect LMI customers and customers in environmental justice populations from the increasingly high energy burdens that will disproportionately impact these customers as more ratepayers leave the gas system in the transition to a net-zero future (Attorney General Initial Comments at 46-47, 52; Attorney General Final Comments at 3-4). The Attorney General asserts that the high upfront investment required to transition to alternatives, such as heat pumps, creates inequities for LMI customers as these households often lack savings, disposable income, and access to credit, which prevents them from affording clean energy alternatives (Attorney General Initial Comments at 47-48). The Attorney General adds that likewise renters may be poorly positioned to participate in and benefit from the energy transition as renters often are responsible for heating bills yet have no control over the heating system and a landlord may not be motivated to make necessary upfront investments (Attorney General Initial Comments at 48; Attorney General Final Comments at 3-4). The Attorney General further observes there is a disproportionate impact to health and safety experienced in certain communities (e.g., due to pollution or the siting of energy infrastructure), including environmental justice populations (Attorney General Initial Comments at 50).

The Attorney General argues that protection for LMI ratepayers must be directionally consistent with reducing dependence on natural gas and should minimize the risk that customers unable to migrate end up with a disproportionate share of transition, embedded, or stranded costs (Attorney General Initial Comments at 52). To this end, the Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI ratepayers from high energy burdens and from potential rate increases related to climate investments by both the gas and electric distribution companies, such as implementing a cap on the amount an LMI ratepayer is billed (Attorney General Initial Comments at 52). The Attorney General further recommends that the Department provide targeted support to LMI customers and customers in environmental justice populations when programs are designed to facilitate opportunities for residents to access cleaner energy alternatives (Attorney General Initial Comments at 52; Attorney General Final Comments at 17).

Several commenters disagree with implementing a migration charge as suggested by the Consultants (see, e.g., Acadia Center Initial Comments at 24-25; RMI Initial Comments at 3; Sierra Club Initial Comments at 18-19; CLF Final Comments at 6). Acadia Center agrees that customer affordability issues should be addressed through a Department investigation of various cost recovery options, but does not believe exit fees are the appropriate approach (Acadia Initial Comments at 24-25).

Sierra Club argues that a migration charge is unfair and undermines the Commonwealth's GHG emissions reduction goals by contradicting incentives to leave the gas system (Sierra Club Initial Comments at 18-19). Sierra Club further contends that this approach fails to account for system costs to which customers contributed but from which they did not benefit (e.g., system expansions and system upgrades to deal with growing demand in certain geographic areas), and questions whether customers would be compensated for those excess contributions when they leave the gas system as well (Sierra Club Initial Comments at 19). Sierra Club also argues that electric ratepayers should not be burdened with gas system transition costs (Sierra Club Initial Comments at 19). Sierra Club suggests that this approach would make the cost of electrification relatively more expensive and would affect not only the customer economics of electrifying from gas, but also of electrifying fuel oil and propane use (Sierra Club Initial Comments at 19).

According to Sierra Club, the best way to minimize low-income energy burdens is to fully electrify low-income housing as part of a high electrification strategy given that the Pathways Report shows that energy burdens of low-income customers would be lowest for those who fully electrify (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). Sierra Club states that while it is important to implement policies such as low-income rates to mitigate impacts on those low-income customers left on the gas system, the priority should be implementing policies and funding programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). LEAN also supports protection of low-income customers from rate increases under the pathways and advocates for an increase to low-income discounts (LEAN Initial Comments at 17; LEAN Final Comments at 2-3).

CLF also argues against imposing a migration charge or transition fee on customers leaving the gas system (CLF Final Comments at 6). CLF contends that doing so would essentially serve as a penalty for transitioning to decarbonized technologies (CLF Final Comments at 6). Further, according to CLF, such a framework would ensure that only those who can afford to pay the fee will be able to make the choice to use clean energy options, leaving the most vulnerable residents who are unable to afford the costs to transition to clean energy stranded on an increasingly high-cost gas system (CLF Final Comments at 6). In addition, CLF submitted a "Scoping a Future of Gas Study," which recommends that utility analyses must account for the differences between customer classes and reflect the impact of each scenario on customers in each category, including low-income ratepayers, moderate-income ratepayers, and renters within the residential class, as well as different types of commercial buildings and industrial consumption (CLF Initial Comments at 38). CLF suggests that LDCs must track the rate and bill impacts of each energy transition scenario on customers with reduced ability to make infrastructure choices in their homes, such as LMI households and renters, and find ways to mitigate the effects of any inequitable outcomes (CLF Initial Comments at 38). The analyses for customer affordability must compare overall costs associated with the use of gas as a "bridge" fuel versus direct transition to electricity (CLF Initial Comments at 39). CLF recommends that LDCs also should consider that customers might switch from pipeline gas to delivered fuels if pipeline service becomes uneconomic, and include recommendations to mitigate any negative effects resulting from such choices (CLF Initial Comments at 39).

DOER agrees with the Consultants that it is necessary to protect customers, particularly low-income customers and those in environmental justice populations, from rate shocks by evaluating decarbonization-specific rate structures (DOER Initial Comments at 9, 11). DOER argues that the Department should require the LDCs to conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, which includes recommendations for mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect low-income residents (DOER Initial Comments at 15). DOER asserts that LDCs must balance affordability concerns for customers against continuing to make necessary investments in the gas system to ensure safety and reliability (DOER Final Comments at 19).

The LDCs indicate support for the Commonwealth's climate goals and contend that customer choice should be at the center of any strategy to meet those goals as individual decisions about when and how to adopt electrification and efficiency measures will affect the nature, scale, and magnitude of electric and gas system transformations (LDC Joint

Comments at 93-94, citing Pathways Report at 15). The LDCs support the hybrid electrification pathway because it results in lower energy system costs, providing an incentive for customers to adopt hybrid heating systems (LDC Joint Comments at 75). The LDCs support the Consultants' suggestions for potential rate designs, such as a new hybrid heating rate class and critical peak pricing, to incentivize customers to adopt or remain on hybrid heating systems (LDC Joint Comments at 75). To ensure customer equity, LDCs are considering potential financial transfers from electric utilities to gas utilities as an approach to fund transition costs (LDC Joint Comments at 75). The LDCs assert this arrangement recognizes the multiple benefits of maintaining gas system functionality, including better utilization of the electrical system, avoidance of significant electrical system upgrade costs, and the maintenance of an alternative energy source in the event of blackouts (LDC Joint Comments at 75). The LDCs argue that achieving the levels of electrification modeled in each pathway will require significant customer education efforts, as well as development of supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95).

3. Analysis and Conclusions

a. Introduction and Summary

In opening this investigation, the Department sought to examine strategies to enable the Commonwealth to move into its net zero GHG emissions energy future while simultaneously safeguarding ratepayer interests. As detailed by the Consultants and LDCs and reinforced by several stakeholder comments, customers are expected to see considerable impacts through the affordability and equity implications of the transition to clean energy alternatives. Namely, customers will face challenges with respect to the upfront costs necessary to invest in clean technologies, rate increases for a declining number of customers remaining on the gas system, and resultant equity impacts, especially for LMI ratepayers and environmental justice populations.

In discharging our responsibilities under G.L. c. 25, the Department must prioritize affordability and equity in addition to safety, security, reliability of service, and reductions in GHG emissions to meet statewide emissions limits and sublimits. G.L. c. 25, § 1A. As electrification efforts expand, ensuring affordability and equity is of particular importance to avoid overburdening customers financially, particularly those who already bear higher burdens in terms of not only costs but other cumulative impacts. The Department acknowledges that the ability to meet these goals will depend on a variety of factors, including the magnitude and pace of customer transition, and legislative and regulatory changes. The Department remains committed to ensuring that its future regulatory policies are aimed at addressing barriers to expeditious customer transition to decarbonized energy options, while mitigating challenges with affordability and equity.

Throughout this proceeding, numerous stakeholders and individuals raised concerns regarding the ability of customers to afford the costs of the transition away from gas, as well the potential inequitable impacts to customers, especially those most vulnerable. The Consultants, as well as several stakeholders, propose a host of solutions to address these issues. Upon examination of the challenges and proposed strategies related to affordability identified during this proceeding, the Department has determined that further investigation is necessary and herein sets forth several areas for future evaluation that will focus on informing the strategies and any necessary regulatory changes to balance affordability and equity with the need to transition into a clean energy future as quickly and aggressively as is practicable. We discuss these areas of future investigation below.

b. Transition Costs

With respect to transition cost considerations, the Department recognizes that the increasing number of gas customers leaving the gas system likely will result in higher rates for those customers remaining on the system. The Department shares commenters' concerns regarding barriers preventing LMI customers from transitioning away from gas, while those same customers would bear a disproportionate energy burden by remaining on the gas system. We agree that new regulatory support and strategies will be needed to minimize the negative implications of this potential cost shifting and to maximize affordability.

The Department supports the Consultants' suggestion that an appropriate starting point is the development of a framework to identify transition costs and quantify these costs to understand the full scope of the cost impacts associated with the various decarbonization strategies, and then to evaluate the impact of those costs on ratepayers. The Department envisions that this framework should, at minimum, include identifying and quantifying the following transition costs: (1) uncollected costs from customers who have departed the gas system; (2) costs associated with design and implementation of regulatory reforms, including geographically targeted electrification, NPAs, coordinated planning efforts between electric and gas utilities, and accelerated depreciation; (3) workforce transition and training costs; and (4) costs associated with restructuring or realigning of gas supply portfolios (Regulatory Designs Report at 42).

Once quantified, the impact of transition costs on ratepayers, particularly LMI customers and environmental justice populations, should be evaluated fully. Importantly, this evaluation should encompass a broad range of considerations, including but not limited to: (1) bill impacts by customer class (short and long term as well as percentage of cost increase relative to household income); (2) GHG emissions reductions; (3) public health and safety; and (4) equity[74] under the various pathways. The Department is interested in DOER's recommendation that the LDCs conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, including potential mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect LMI ratepayers. As discussed in Section VI.E above, the Department favors a robust alternatives analysis, and we see a geographical marginal cost analysis to be a potentially valuable and informative part of that process. As suggested by the Attorney General, the Department will prioritize consideration

74 In this context, evaluation of equity considerations should include impacts on LMI customers, environmental justice populations, renters, and people of color, both in terms of energy burden and energy-related health and safety impacts. An equity analysis should consider the disproportionate and inequitable distribution of burdens and benefits that currently exist as well as future projections.

of any impacts that result in disproportionate and inequitable distribution of burdens and benefits when making any future regulatory decisions.

c. Alternative Cost Recovery

The Department agrees that we should evaluate and consider alternative cost recovery mechanisms. The Consultants suggest implementing migration and transition charges, along with financing transition costs through securitization, as potential cost recovery mechanisms to alleviate the increasing burdens on customers as more and more leave the gas system. Several commenters express support for types of mechanisms that help mitigate cost and equity impacts to customers, but also argue that implementing the Consultants' proposed mechanisms is inappropriate.

While the Department acknowledges the potential benefits of implementing a migration charge or exit fee for migrating off the gas system—such as reducing the costs that will shift to the remaining gas customers and minimizing the potential for non-recovery of embedded costs—the potential burdens and impacts on those customers and their decision to adopt clean alternatives remain unknown and untested. The Department is concerned that charging a fee to exit the gas system may disincentivize some customers from pursuing electrification. Similarly, while the Department acknowledges the potential benefit that securitization methods could yield (i.e., in terms of lowering borrowing costs and reducing customer rate shocks), the full scope of the impacts on customers and the gas and electric systems remains to be seen.[75] For these reasons, the Department declines to adopt the proposed alternative cost recovery mechanisms at this time and we will examine other cost recovery mechanisms in a future investigation.

Lastly, the Department agrees with several commenters that there is a need to adopt a rate mechanism aimed at protecting LMI customers from high energy burdens and potential rate increases as they transition from gas to electricity. As mentioned in Section VI.B above, the Green Communities Act directs that 20 percent of three-year energy efficiency plan budgets be allocated to low-income energy efficiency. G.L. c. 25, § 21(b)(1). We determine that there should be additional policies and programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy and, in fact, benefit in the near-term from electrification opportunities. The Department encourages the LDCs to work with the Energy Efficiency Advisory Council, including LEAN, to explore strategies to better reach underserved populations and hard-to-reach customers, including renters and landlords, LMI customers, and environmental justice populations. The Department also previously directed the LDCs to weatherize prior to or as part of an electrification project to ensure that overall energy consumption will decrease, while minimizing ratepayer bill impacts, particularly for LMI customers, for purposes of acquiring all cost-effective energy efficiency under the Green Communities Act. 2022-2024

75 The Department notes that while G.L. c. 164, §1H, provides that the Department shall approve an electric company's securitization plan that maximizes rate affordability to ratepayers, the statute does not explicitly apply to LDCs.

Three-Year Plans Order at 107-108. An enhanced incentive structure that includes weatherization for low-income and environmental justice population customers in addition to incentives for heat pump conversions will ensure a reduction in energy consumption and minimize bill impacts. The LDCs should encourage, through education and enhanced incentives, proper weatherization of all customer homes in advance of heat pump installation. LDCs should also ensure that contractors properly size heat pumps prior to installation. Failing to do so potentially increases energy costs for customers. 2022-2024 Three-Year Plans Order at 107-108.

Further, we acknowledge the Recommendations of the Climate Chief, Melissa Hoffer, developed pursuant to Executive Order No. 604, §3(b), which recommends that the Department "prioritize any rate reform necessary to ensure that electric bills will be affordable for all households, particularly those with low and moderate incomes."[76] As noted in Section III above, the Department will investigate this issue further as we evaluate methods to ensure affordability and equity in light of higher energy burdens on LMI customers.

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[76] Hoffer, Melissa, Office of Climate Innovation and Resilience, "Recommendations of the Climate Chief pursuant to Section 3(b) of Executive Order No. 604," pages 40-43 (October 23, 2023), available at: https://www.mass.gov/doc/recommendations-of-the-climate-chief-october-25-2023/download (last visited November 29, 2023).

G. Develop LDC Transition Plans and Chart Future Progress

1. Introduction and Summary

The sixth regulatory recommendation includes developing transition plans and evaluating progress toward the Commonwealth's climate targets. The Consultants state that the transition toward achieving climate targets will require (1) periodic reporting and (2) an iterative planning process that reflects lessons learned and new developments (Regulatory Designs Report at 46). The Consultants identify the following reporting and planning processes for inclusion in the new LDC transition plans:

1) Evaluation of LDC transition plan progress toward achievement of climate goals and addressing challenges;

2) Review and pre-approval of future LDC capital investments with a focus on necessary gas system replacements and identification of strategic opportunities to avoid new gas infrastructure through electrification and alternative options;

3) Establish a framework to review and optimize cross-coordination planning between gas and electric utilities;

4) Establish a framework for review and approval of cost recovery mechanisms for LDC capital investments and pilot projects;

5) Evaluation of customer affordability metrics;

6) Evaluation of key initiative data such as number of renewable natural gas customers, GHG emissions calculations, rates and bill impacts, and impacts on environmental justice populations with each plan filing; and

7) Incorporation of performance metrics and incentives to align LDCs' financial incentives with the goals of the Commonwealth (Regulatory Designs Report at 46-47).

Each LDC filed a Net Zero Enablement Plan, an initial transition plan for meeting the Commonwealth's 2050 goals (Framework and Overview at 17). The LDC Net Zero

Enablement Plans are designed to continue energy efficiency efforts consistent with the three-year energy efficiency plans, and to advance decarbonization and the Consultants' recommended regulatory designs in the short term. (Framework and Overview at 17). Included in the LDC transition plans is a proposed Model Tariff that would allow the LDCs to recover costs associated with their respective Net Zero Enablement Plans (Framework and Overview at 18-19). The LDCs seek Department approval of a framework for future iterations of the Net Zero Enablement Reports and the Model Tariff (Framework and Overview at 18-19). Each LDC proposes to file a Net Zero Enablement Plan on a three-year cycle, to align with the three-year energy efficiency cycle, using a five-year and ten-year planning horizon (Framework and Overview at 18). The Consultants note that GSEP capital investments would not be included in the transition plans because there is a process in place for Department review and approval for such expenditures (Regulatory Designs Report at 46). The LDCs propose that the Department review their initial and future three-year transition plans pursuant to the following standard of review: "The LDC's transition portfolio is reasonably designed to contribute to the reduction of GHG emissions to meet net-zero emissions by 2050, without compromising the safety, reliability and affordability of service offered to current customers" (Framework and Overview at 18).

2. Summary of Comments

a. Comprehensive and Coordinated Planning

Most commenters agree that comprehensive planning is needed to guide future investments and meet decarbonization objectives. The Attorney General recommends that the

Department take several steps to support LDC comprehensive planning such as: (1) requiring LDCs to file a comprehensive geographic distribution system mapping report; (2) implementing an investment alternatives calculator;[77] (3) mandating an alternatives analysis for approval of LDC proposals for alternative sources of methane or combustible gas; (4) directing LDCs to file plans that demonstrate the achievement of required GHG emissions reductions; and (5) reviewing LDC forecast and supply planning to better align GHG emissions reduction requirements (Attorney General Final Comments at 10-13). The Attorney General explains that without a full map of the gas system, the regulatory framework would continue to perpetuate piecemeal planning and siloed decision making which may impact the cost-effective achievement of net zero emissions by 2050 (Attorney General Final Comments at 10). The Attorney General maintains that such a map could help identify areas that are best suited for targeted electrification (Attorney General Final Comments at 14). DOER also supports requiring LDCs to submit a geographic distribution system map (DOER Final Comments at 10).

In addition, commenters agree that coordinated planning between gas and electric distribution system companies is necessary. The Attorney General recommends that the Department require electric distribution company participation in gas system investment proceedings (Attorney General Final Comments at 15). The Attorney General contends that the Department cannot adequately evaluate any proposed investment without joint electric and

[77] We address the suggestion of an investment alternatives calculator in Section VI.E.

gas planning (Attorney General Final Comments at 15). Other commenters such as Acadia Center and CLF oppose having LDCs lead the transition plans (Acadia Center Final Comments at 2; and CLF Final Comments at 7). Acadia Center and CLF argue that the LDCs have a financial interest in maintaining the gas system, which creates a conflict of interest in leading the transition plans (Acadia Center Final Comments at 2; CLF Final Comments at 7). CLF avers that LDCs should be treated as stakeholder participants in the "future of gas," while Acadia Center recommends implementing an independent planning authority to lead coordinated planning (CLF Final Comments at 7; Acadia Center Final Comments at 1; Acadia Center Initial Comments at 27-28). Public commenters conveyed support for developing transition plans, but many expressed concerns with the proposal that the LDCs lead the transition.

The LDCs disagree with Acadia Center's recommendation to create a third-party planning authority to oversee the transition plans (LDC Joint Comments at 78). The LDCs argue that creating a new third-party planning authority would conflict with prior Department precedent and the rights and obligations conferred upon utility companies by law and statute (LDC Joint Comments at 78). In particular, the LDCs posit that the Department has long deferred to the judgment and expertise of regulated utility companies when it comes to operating and maintaining their systems (LDC Joint Comments at 80, citing Boston Gas Company and Colonial Gas Company, D.P.U. 13-78, at 13 (2014)). Moreover, the LDCs maintain that it is appropriate for utilities to develop their own investment plans because they bear the responsibility of maintaining a safe and reliable service that is compliant with all federal and state regulatory and statutory requirements (LDCs Joint Comments at 81). Regarding specific analytical constructs for evaluating potential gas network investments proposed by the Attorney General and DOER (e.g., investment alternatives calculator or geographic mapping and marginal cost analysis), the LDCs argue such tools would reduce network planning to consideration of selected quantifiable parameters and, therefore, would be unable to capture the broad range of considerations that are required to make coordinated investment decisions (LDC Joint Comments at 82, citing Exh. DPU-Comm 7-2).

b. Limiting Incentives for Gas System Growth

Several commenters propose recommendations regarding GSEPs. The Attorney General asserts that the Department should consider climate objectives as part of GSEP review and require LDCs to demonstrate that the proposed investment is the least-cost alternative to improve safety and reduce leaks (Attorney General Initial Comments at 30). Additionally, the Attorney General proposes that the Department form a working group to make recommendations for potential changes to GSEPs (Attorney General Attorney General Initial Comments at 44). Similarly, DOER contends that LDCs should be required to address how specific GSEP investments correlate with a parallel geographical marginal cost analysis (DOER Final Comments at 18). DOER, Sierra Club, and CLF agree with revising the current GSEP process so investments in gas infrastructure can be minimized to the greatest extent practicable (DOER Final Comments at 17; CLF Initial Comments at 8; Sierra Club Initial Comments at 20). Several commenters echoed the importance of minimizing further gas system investments (see, e.g., HEET Comments at 8; LEAN Initial Comments at 10-11;

Muzzey Comments at 1). Commenters cited concerns regarding stranded assets and perpetuating the use of fossil fuel gas through gas system investments (see, e.g., RMI Initial Comments at 11; Werlin Comments at 1 (May 6, 2022); Lipke Comments at 1 (May 6, 2022)). Other commenters called for the end of both gas line extensions and the addition of new gas customers to the system (see, e.g., HEET Comments at 33; McCord Comments at 3; PLAN Initial Comments at 4).

The LDCs reiterate that the proposed transition plans exclude GSEP-related investments because there already is a process in place for Department gas system review and approval (LDCs Joint Comments at 81, citing Regulatory Designs Report at 46). The LDCs maintain that their respective GSEPs are consistent with the Gas Leaks Act and note that the Department consistently has found that the replacement of aging infrastructure under GSEPs achieves the goals of improvements in public safety, infrastructure reliability, and the reduction of lost and unaccounted for ("LAUF") natural gas. (LDC Joint Comments at 85, citing Fitchburg Gas and Electric Light Company, D.P.U. 20-GSEP-01, at 9 (2021)). Additionally, the LDCs note that they already are required to show that their respective GSEPs reduce emissions through annual filings with MassDEP (LDC Joint Comments at 85). The LDCs do not object to evaluating possible modifications to GSEPs as part of a working group provided they have adequate representation (LDC Joint Comments at 85).

Other recommendations are intended to further disincentivize gas system growth. For example, the Attorney General avers that LDCs should no longer be permitted to recover costs for marketing related to promoting gas service (Attorney General Initial Comments at 41). The Attorney General argues that these costs are not aligned with the Commonwealth's decarbonization goals and therefore expansion advertising should no longer be funded by ratepayers (Attorney General Initial Comments at 41). Similarly, the Sierra Club argues that incentives for gas appliances should be phased out (Sierra Club Initial Comments at 21). The Attorney General makes an additional recommendation to revise existing performance-based ratemaking ("PBR") mechanisms to establish incentives and disincentives designed around the gas utilities' progress in compliance with the Climate Act mandates (Attorney General Initial Comments at 40-41). The Attorney General states the Department should consider directing each LDC to submit revised PBR plans instead of waiting for the LDC to file its next base rate case (Attorney General Initial Comments at 40-41).

The LDCs disagree with the Attorney General's recommendation to revise the PBR mechanism (LDC Joint Comments at 88). The LDCs explain that PBR generates a level of revenue for a company to run its business, similar to an annual allowance to cover business operations, which enables the company to make system investments and attain operational and capital efficiencies (LDC Joint Comments at 89). According to the LDCs, these efficiencies create savings which are passed on to customers (LDC Joint Comments at 89). Additionally, the LDCs maintain that the existing PBR framework is not inherently inconsistent with progress toward decarbonization (LDC Joint Comments at 89). The LDCs argue that it is not necessary to revise the existing PBR because a new framework that aligns incentives with decarbonization still would apply with or without the current PBR framework (LDC Joint Comments at 89).

c. Net Zero Enablement Plans

Many commenters request that the Department reject the LDCs' individual Net Zero Enablement Plans and associated Model Tariff (see, e.g., Sierra Club Final Comments at 4; NCLC Initial Comments at 20; CLF Final Comments at 6). Some commenters express concerns that the proposed Net Zero Enablement Plans are biased, inaccurate, profit-driven, and ineffective to adequately transform energy use (Donaldson Comments at 1 (May 6, 2022); NCLC Initial Comments at 14-16; Sierra Club Final Comments at 13-14). In addition, other commenters contend that the Model Tariff is premature and that it is unfair for utilities to offer a product, such as RNG, as a tariffed utility service (see, e.g., Attorney General Initial Comments, App. C at 3-4; SFE Energy Comments at 3-4 (May 6, 2022)). The Attorney General criticizes the Net Zero Enablement Plans, contending that the LDCs are resisting change by seeking to maintain gas infrastructure (Attorney General Initial Comments, App. C at 2). The Attorney General proposes that the Department open a planning docket for the purpose of ensuring LDC compliance with climate mandates before considering the proposed Net Zero Enablement Plans (Attorney General Initial Comments, App. C at 3).

DOER recommends that the Department require the LDCs to develop more detailed three-year plans that propose decarbonization regulatory actions, evaluation of previous metrics, and recommendations for future plans (DOER Initial Comments at 13). DOER proposes that the Net Zero Enablement Plans should include the following: (1) a geographic mapping and marginal cost analysis to demonstrate the interaction of multiple strategies; (2) a demonstration of cost considerations; (3) enhanced proposals for regulatory actions to support decarbonization; and (4) metrics as a tool to evaluate successful strategies (DOER Initial Comments at 14). The LDCs maintain that each proposed Net Zero Enablement Plan pursues a portfolio of the various decarbonization pathways analyzed by the Consultants in an effort to meet the Commonwealth's targets while maintaining safety and reliability (LDC Joint Comments at 17). The LDCs request that the Department review and approve the individual Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 17).

3. Analysis and Conclusions

a. Introduction

The LDCs developed individual transition plans that articulate their role in supporting the Commonwealth's achievement of its climate mandates. The LDCs specifically propose to implement transition plans that include: (1) joint gas and electric planning; (2) periodic reporting; and (3) a Model Tariff to facilitate recovery of costs associated with the Net Zero Enablement Plans (Regulatory Designs Report at 46-47). The LDCs maintain that it is appropriate for utilities to develop their own transition plans and oppose recommendations to implement an investment alternatives calculator or geographic mapping report (LDC Joint Comments at 81-82). As we have stated from the beginning of this investigation, rather than selecting a single pathway for decarbonization, the Department will focus on creating a regulatory planning framework that is flexible, protects customers, and considers a suite of electrification and decarbonization technologies to facilitate the transition. Here we identify certain strategies and processes that will allow the Department and stakeholders to collect and evaluate information, establish common metrics and assumptions, and refine reporting review procedures to maintain and accelerate momentum toward achievement of the Commonwealth's climate targets. Consistent with our "whole of DPU" approach, these will include LDC reporting requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department.

b. Comprehensive and Coordinated Planning

The LDCs propose to establish a process for coordinated planning between gas and electric utilities (Regulatory Designs Report at 46). The Department agrees that coordinated and comprehensive planning between electric and gas utilities is needed to facilitate the energy transition. Gas and electric infrastructure planning will be necessary as consumers transition from using fossil fuel-based heating systems to electric heat pumps. We note that going forward, evaluation of any proposed investments will have to take place in the context of joint electric and gas system planning. The Department emphasizes that joint electric and gas utility planning must occur in a broad stakeholder context so that the LDCs and electric distribution companies exclusively are not defining the process and outcome. The LDCs and electric distribution companies should consult with stakeholders regarding such a joint planning process that, while it is not Department led, may lead to proposals for Department review. We will continue to monitor and define these processes in future proceedings, as necessary.

Next, the Department addresses the practicality of requiring a comprehensive map of the gas distribution network. The Attorney General asserts that a map of all gas system infrastructure will better enable the Department to evaluate proposed gas system investment and alternatives (Attorney General Initial Comments at 23-24). The Department in Section III and Section VI.E above expressed its support of a robust alternatives analysis, for the first time mandating that LDCs must include and demonstrate analysis of alternatives as a prerequisite for cost recovery of infrastructure investments. As to the requirement of a gas system infrastructure map, the Department seeks to balance the need for comprehensive and useable information with the nature of the extensive critical energy infrastructure information ("CEII") inherent in such an undertaking, which is required by public records law to be protected from public disclosure.[78] We therefore decline to order public filing of such mapping with the Department in a Climate Compliance Plan or otherwise. We will, however, explore appropriate means of facilitating such information sharing without compromising CEII.

The Department finds that it would be inappropriate to issue any further directives that could impact potential changes to GSEPs here. The 2022 Clean Energy Act required the Department to convene a stakeholder working group to develop recommendations and

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78 G.L. c. 66, § 6A(e); G.L. c. 4, § 7(26)(n).

legislative changes to align the gas system with statewide emissions limits, as well as encourage the development of geothermal systems. St. 2022, c. 179, § 68. The GSEP working group has met several times since its initial meeting in April 2023.[79] Each of the LDCs, as well as many of the parties to this proceeding, is participating in the GSEP working group process, and most of the topics raised by the Attorney General and other stakeholders are being explored in that forum. The GSEP working group is expected to produce its findings and recommendations to the Legislature by the end of the year.

c. Climate Compliance Plans

The Department appreciates the LDCs' efforts to design the initial Net Zero Enablement Plans. As a threshold matter, Section 77 of the 2022 Clean Energy Act dictates that the Department shall not approve any company-specific plan in this investigation prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, while the LDCs' Net Zero Enablement Plans lay out the companies' strategies to achieve compliance with climate objectives mandates,[80] which may inform the regulatory framework we seek to establish here, we cannot approve such a plan or a Model Tariff

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79 See https://www.mass.gov/info-details/gseps-pursuant-to-2014-gas-leaks-act (last visited November 29, 2023).

80 The LDCs explain that certain pathways evaluated in the Net Zero Enablement Plans, such as efficient gas equipment installation, may build on the three-year plan activities by offering additional incentives, complementary measures, or implementation practices that further advance efficient gas equipment installations, but that do not fall within the parameters of the Department's precedent for cost-effectiveness applicable to energy efficiency sectors, programs, or core initiatives (Exh. DPU-Comm 1-11).

without full adjudication. This proceeding is an investigation and not an adjudicatory proceeding. Consistent with the legislative directive, the Department will review and approve company-specific plans in subsequent adjudicatory proceedings.

To that end, the Department directs each LDC to file individual Climate Compliance Plans every five years, with the first such Plan being due on or before April 1, 2025.[81] Each Climate Compliance Plan should expand on previous Net Zero Enablement Plans by demonstrating how each LDC proposes to: (1) contribute to the prescribed GHG emissions reduction sublimits set by EEA for both Scope 1[82] and Scope 3[83] emissions; (2) satisfy customer demand safely, reliably, affordably, and equitably using known and market-ready technology available at the time of the filing; (3) use pilot or demonstration projects to assist

81 Subsequent Climate Compliance Plans would be due in 2030, 2035, and 2040. The plans should include a five- and ten-year planning horizon.

82 The U.S. Environmental Protection Agency ("EPA") defines Scope 1 emissions as "direct greenhouse emissions that occur from sources that are controlled or owned by an organization." Scope 1 and Scope 2 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance (last visited November 29, 2023).

83 The EPA defines Scope 3 emissions as emissions that "result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain." Scope 3 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-3-inventory-guidance (last visited November 29, 2023).

in identifying investment alternatives; (4) incorporate the evaluation of previous metrics[84]; and (5) implement recommendations for future plans.

Each electric distribution company operating in an LDC's service area will be required to participate in the Climate Compliance Plan gas planning process.[85] Each Climate Compliance Plan should detail the total investment required and should also include a description of at least one alternative method to meet the required emissions reductions, providing the estimated costs for the considered alternative, and a demonstration that the proposed plan is superior to the alternative. To track compliance with the Commonwealth's interim emissions reduction deadlines, each LDC will be required to file an informational Climate Act Compliance Term Report Filing nine months after each interim deadline (i.e., 2025, 2030, 2035, 2040) indicating whether or not the LDC achieved the required emissions reductions.

d. Climate Compliance Incentives

The LDCs state that the planning and evaluation process could be used to design performance metrics and incentives to align the LDCs' financial incentives with the Commonwealth's goals (Regulatory Designs Report at 47). A PBR mechanism can provide such an incentive for an LDC to take actions aligned with the Commonwealth's climate

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84 Evaluation of previous metrics would not be applicable to the first Climate Compliance Plan filed.

85 The Climate Compliance Plans should also include customer, stakeholder, and community input where practicable.

policy and mandates to reduce its sales of methane gas through a series of measures to encourage gas efficiency, demand response, and electrification, as well as reducing LDC system and customer emissions of methane and carbon dioxide. In recent Orders, the Department has approved a PBR framework for LDCs, recognizing that there is a fundamental evolution taking place in the natural gas local distribution industry in Massachusetts.[86] Currently, the Department requires a utility seeking approval of an incentive proposal like PBR to "demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates and reduced administrative burden in regulation."[87] To better align gas PBRs with the Commonwealth's long-term future of the gas system in a net-zero 2050 economy, the Department finds that it should amend the existing PBR framework to establish incentives and disincentives reflecting the gas utilities' progress toward compliance with the Climate Act mandates, and achievement of their approved Climate Compliance Plans. Accordingly, the Department directs the LDCs to propose climate compliance performance metrics in their next PBR filings.

86 See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 56; Boston Gas Company, D.P.U. 20-120, at 66-67 (2021).

87 See NSTAR Gas Company, D.P.U. 19-120, at 59.

VII. CONCLUSION

The Department herein has set forth a regulatory strategy for pursuing an energy future that begins to move the Commonwealth beyond gas and toward its climate objectives. As we have detailed, this will include new reporting and analysis requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department. Going forward, the Department will seek to facilitate a safe, orderly, and equitable transition for the LDCs and their customers through these processes while pursuing the Commonwealth's 2050 GHG emissions reductions mandate and interim targets.

VIII. ORDER

Accordingly, after due consideration, it is

ORDERED: That the Massachusetts gas local distribution companies shall comply with the directives contained in this Order.

By Order of the Department,

James M. Van Nostrand, Chair

Cecile M. Fraser, Commissioner

Staci Rubin, Commissioner

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-6.1a	
Respondent: H. J. Decker	
Page: 1 of 1	

Question: 1. Please refer to DTE's response to MNSCDG-2.7a and the Forecast Summary 2023 tab and the "Assumptions - New Way" tab in the attachment titled in the "U-21291 MNSCDG-2.7a -Jun 2023 New Markets Attachments - 2023 Rate Case." DTE relies on Global Insight's forecast for new residential housing starts to estimate the number of new housings with gas services within DTE's territory, assuming that a factor of 78 percent for "Michigan State Nat Gas Penetration" and a factor of approximately 32 percent for "DTE Gas Service Territory Customer Share" through 2033. The share of DTE gas service customers in the state is based on the data for 2013 per the "Assumptions - New Way" tab.

a. What is the data source for the 78 percent factor for natural gas fuel penetration at the state level?

Answer: At the time, research was done to prepare a baseline to apply the Global Insights housing starts data. A Michigan Energy Overview showed nearly 80% of Michigan households use natural gas as their primary source for heat heating. Detroit News – Oct 26, 2012, article listed 77% of MI households heat with natural gas. And so, 78% was selected to use. The links to the articles are no longer available. The forecasts have been within a reasonable range for routine growth. We apply manual targets and expectations as we see new information on routine results as well as proactive conversions to produce the total.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-2.10c	
Respondent: G. H. Chapel	
Page: 1 of 1	

Question: 10. Please refer to DTE Gas's sales forecast methodologies described on pages 15 to 28 of Direct Testimony of Chapel.

c. Does DTE Gas incorporate in its sales forecasts the impacts of the state's climate and clean energy laws, in particular Senate Bill 273 that enhances the EWR programs and also supports electrification and fuel switching? If so, please explain how the company incorporated the impact. If not, explain the company's expectation about the impact of Senate Bill 273 on natural gas sales.

Answer: DTE Gas Company did not incorporate in its sales forecasts the impacts of the state's climate and clean energy laws, including Senate Bill 273. In this case, DTE Gas Company has no expectations about the impact of Senate Bill 273 on natural gas sales.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-5.11gi	
Respondent: K. M. Fedele	
Page: 1 of 1	

Question: 11. Please refer to Figure 5 on page 9 of DTE's Gas Delivery Plan 2024-2033 (Exhibit A-12 Schedule B5.6)

g. Did DTE estimate the impact of electrification on residential energy consumption and sales forecasts through 2033?

i. If yes, please explain how DTE quantified this impact. If no, please explain why not.

Answer: No. Currently, given the current legislation and costs, we don't believe electrification will have a significant impact on natural gas consumption in the next ten years. If it becomes significant in the future, our current methodology would be adapted to include the impact.

Attachment: None

Co-Respondent(s): H. J. Decker

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-1.8h	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 8. Please refer to Exhibit A-12 Schedule B5.5, pages 31-34 of 45 (Mesick-Buckley AEP Project summary).

h. What, if any, upfront or monthly fixed or volumetric charge will customers served by the Mesick-Buckley project pay beyond standard gas bills, as contributions to the cost of construction of the Mesick-Buckley AEP?

Answer: Homeowners within the Mesick-Buckley project will have the option of an upfront payment of $2,212 or a monthly fixed surcharge of $27.76 per month for a term of 10-years. Businesses will only have the upfront payment option of $2,212.

Attachment: None

MPSC Case No: U-21291
Requester: MNSC
Question No.: MNSCDG-1.8fi
Respondent: E. M. Abona
Page: 1 of 1

Question: 8. Please refer to Exhibit A-12 Schedule B5.5, pages 31-34 of 45 (Mesick-Buckley AEP Project summary).

f. Does the Company expect that all 1,063 identified customers will choose to connect to the gas system within 5 years of the Mesick-Buckley project's completion?

i. If so, please provide the evidence used to support that assumption.

Answer: Due to the low cost and savings as detailed in the EIED application, DTE expects all 1,063 identified customers to choose to connect to the gas system within 5 years of the project's completion.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-1.8b	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 8. Please refer to Exhibit A-12 Schedule B5.5, pages 31-34 of 45 (Mesick-Buckley AEP Project summary).

b. Refer to Drivers of Project on page 31. How many inquiries has DTE Gas received from homeowners in the Mesick-Buckley area, over what time frame, and from how many unique households? (This question does not seek the identities of any of these customers.)

Answer: The Company does not track specific inquiries.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-1.9	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: 9. In the event that customer connections or consumption are lower than projected by DTE for the Mesick-Buckley AEP, will other DTE ratepayers pay more for this project than projected in the Company's LC EIED application and in Exhibit A-12, Schedule B5.5, page 31?

Answer: No. Rates in this case assume these connections and volumes occur and are included in in witness Chapel’s testimony. If volumes/connections are not obtained, DTE shareholders will bear the costs.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-4.4ai	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: Please refer to DTE's response to MNSCDG-1.9. In this response, DTE states that "If volumes/connections are not obtained, DTE shareholders will bear the costs."

a. What is the time period across which DTE calculates borne costs?

i. Does DTE's response to MNSCDG-1.9 reflect costs to DTE shareholders over the full life of the assets installed for the Mesick-Buckley AEP, or only for the period between the installation of the assets and DTE's next rate case?

Answer: DTE's response to MNSCDG-1.9 reflect costs during each general rate case filing, the number of historical customers and their historical average usage are used to develop a sales forecast for the projected test year with consistent methodology which is laid out in Mr. Chapel's testimony. The rates approved by the Commission in each general rate case are set to recover costs authorized in that case until DTE files its next general rate case. It is during these proceedings when all the sales volumes as well as the costs included in the revenue requirement are examined. Any increases or decreases in sales and costs are reset to those levels deemed reasonable and prudent.

Attachment: None

MPSC Case No: U-21291	
Requester: MNSC	
Question No.: MNSCDG-4.4bi	
Respondent: E. M. Abona	
Page: 1 of 1	

Question: Please refer to DTE's response to MNSCDG-1.9. In this response, DTE states that "If volumes/connections are not obtained, DTE shareholders will bear the costs."

b. In the event that a) customer connections or volumes are lower than projected by DTE for the Mesick-Buckley AEP, and b) DTE shareholders would bear the resulting net costs, how would DTE calculate the costs that DTE shareholders would bear, in the next rate case?

i. Would some assets not be included in rate base because they would not be considered used and useful?

Answer: No, the company seeks recovery of all capital expenditures spent in the test period given that assets installed are serving customer demand and are used and useful.

Attachment: None

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-21291

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony and Exhibits of Dr. Asa S. Hopkins on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club** was served on the following:

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The statements above are true to the best of my knowledge, information, and belief.

TROPOSPHERE LEGAL, PLC
Counsel for MEC, NRDC, & SC

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