May 6, 2022

Sarah Smegal
Hearing Officer
Department of Public Utilities
1 South Station, 5th Floor
Boston, MA 02111

RE: DPU 20-80 Submission of Alternative Proposals

To the Massachusetts Department of Public Utilities

On April 15, the Hearing Officer issued a solicitation for "comments that raise issues with the consultants' reports and the LDCs' proposals and comments that make alternative proposals, particularly alternative regulatory framework proposals." This letter is a response to that solicitation.

My response contains four main elements:

1. A comment on defining DPU's role in achieving the Commonwealth's Net Zero target with a specific focus on the provision of gas.
2. A comment on defining DPU's role in achieving the Commonwealth's Net Zero target with a specific focus on the provision of gas.
3. A comment on the local distribution companies' independent consultant study and proposals
4. An alternative proposal for DPU's role in overseeing the thermal transition.

Supporting these comments are a set of working papers on:

1. The limitations of bioenergy resources;
2. A perspective of heating hybridization strategies critiquing the strategy analyzed and proposed by the LDCs; and,
3. An analysis of customer transitions.

Thank you for considering these comments and your efforts in this vital work.

Sincerely,

Michael Jay Walsh, Ph.D.
Independent Decarbonization Researcher & Consultant
Somerville, Massachusetts

Enclosures
cc: Sarah Smegal, Esq., Hearing Officer, Department of Public Utilities
Service List

Comment 1: DPU's role in achieving the Commonwealth's Net Zero target with a specific focus on the provision of gas.

Massachusetts State Law Chapter 21N Section 3 established a *net zero* greenhouse gas emissions limit, while Chapter 25 Section 1A[1] aligns the Department of Public Utilities (DPU) responsibilities with that limit.

A *net zero* target refers to:

(1) the mitigation of emissions necessary to balance regulated gross greenhouse emissions with durable and additional removals; and,

(2) the transition of existing fossil energy systems to *net zero emissions energy systems* that align with global efforts to achieve global net zero emissions with ambitious climate targets adopted by the United Nations Framework Convention on Climate Change.

While this second point may seem pedantic, it reflects an important nuance that local or sectoral efforts to mitigate greenhouse gas emissions must not unnecessarily burden efforts to decarbonize other regions or regulated sectors. Since climate change is well known to be a global problem, it is clear that Massachusetts' *net zero* law intends to ensure that its decarbonization actions are compatible with global efforts. Thus efforts to comply with the statutory net zero targets need to pursue strategies consistent with the latest scientific understanding of net zero emissions energy systems.

The characteristics of net zero emissions energy systems are still being understood. The current scientific understanding[2] emphasizes seven characteristics:

1. Limited and targeted use of fossil fuels
2. Minimal, zero, or negative CO_2 emissions from electricity
3. Widespread electrification of end uses
4. Alternative fuels are primarily used in sectors that are difficult to electrify
5. Using less energy and materials and using them more efficiently
6. Greater reliance on integrated energy system approaches
7. Use of carbon dioxide removal technologies

A practical example of how the current understanding should influence the DPU's approach relates to applying renewable fuels to decarbonize heat. Over-reliance on renewable fuels can challenge the ability for other net zero goals to be achieved. Because renewable fuels (#4) rely on biologically or captured carbon and consume renewable electricity, excessive use of such fuels outside of sectors that are difficult to electrify can conflict with items #2 and #7.

Considering the characteristics of net zero emissions energy systems described above, the department's approach to decarbonization should seek to pursue strategies that aim to:

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[1] *In discharging its responsibilities under this chapter 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.*

[2] Azevedo et al. *Net-zero emissions energy systems: What we know and do not know,* Energy and Climate Change, Volume 2, 2021, https://doi.org/10.1016/j.egycc.2021.100049.

1. **Maximize the use of ambient heat** from the air, ground, or water bodies through the widespread promulgation of heat pump technologies.
2. **Rapidly scale renewable electricity generation and distribution infrastructure** to meet growing electric demands.
3. **Minimize energy losses** in buildings through comprehensive energy efficiency, weatherization, and systems integration (e.g., waste heat recovery; ambient and hot water district systems where applicable).
4. **Strategically and minimally** use fossil or alternative fuels to support system reliability at appropriate points in the system.
5. **Rightsize the gas system** to reduce costs and methane leaks.

In aligning its policy with its net zero mandate, the DPU should prioritize fundamental systems change over incremental actions and actions that seek to achieve sector net zero targets at a cost to other sectors or regions. For example, blending renewable hydrogen into the pipeline system results in only incremental emissions reductions. Its intentional prioritization comes at the cost of decarbonizing other sectors such as industrial heat shipping or fertilizer production.

Comment 2: Defining DPU's role in Minimizing Ratepayer Impacts as it Aligns its Regulated Industries with the Commonwealth's Net Zero Target

Regulated gas utilities have been isolated from competition because pipeline-delivered gas delivered under the regulatory compact has offered consumers the highest perceived value heating resource at the lowest cost. This previously secure market position will be eroded by competition in the coming years because:

1. Space conditioning heat pumps will offer consumers lower operational cost heating for most days of the year and provide additional value in their ability to cool and be easily zoned.
2. An improving understanding of effective whole building electrification strategies.
3. Increased consumer preference for induction cooking and the improved performance of electric resistance stovetops, combined with the increasing concerns about the health impacts of combustion-based cooking indoors.
4. Increased cost-effectiveness and practicality of non-pipeline fuels (such as wood and propane) relative to the pipeline gas system to meet peak energy demands, resiliency needs, or heating electrification.
5. A vicious cycle of customer exits continuously reinforced by rate increases needed to meet the system's revenue requirement typical rate-setting approaches.

The DPU needs to consider the dynamic roles of *policy* and *market* mechanisms in the evolution of gas consumption and gas distribution in the coming years. The policy mechanism encompasses a range of potential strategies for guiding the decarbonization of the gas system. There is no current policy for aligning the pipeline gas sector with the Commonwealth's net-zero target.

The market mechanism is guided by consumer preferences and the production of technologies that seek to meet consumer preferences and policy needs (innovation). The market has the potential to create uncontrollable change by rapidly and continuously (e.g., past 2050) eroding demand for pipeline-delivered gas. Despite the market's potential to evolve rapidly, it will not evolve fast enough to achieve the Commonwealth's net-zero target in the absence of policy. Without a policy to guide it, there will be vast economic efficiencies of investing in more than one energy system at the same time.

The Massachusetts 2050 Decarbonization Roadmap (Summary Report Page 51) recognized the implications of these factors, raising the concern that:

> *A strategy reliant on the continued use of pipeline gas for building heat carries asymmetric risks compared to electrification. A future increase in the price of pipeline gas, together with increasing reductions in costs associated with heat pumps, could result in a significant cost-driven market advantage for heat pumps that, regardless of policy, leads to a large, uncontrolled customer exit from the gas system. The potential for an uncontrolled exit driven by market economics raises significant additional equity concerns.*

Thus, under current rate-making practices, a policy-driven or uncontrolled exit from the gas system can significantly expose those who remain on the gas system to rate increases necessary to meet the system's revenue requirement.

A managed rightsizing of the gas system is thus necessary to achieve the Commonwealth's net zero targets and minimize customer impacts. Contrary to the LDCs' collective claim that rightsizing the gas system constrains consumer choice, a managed transition – including one that allows for the use of non-pipeline fuels – should expand consumer choice and the accessibility of low-carbon heating options and minimize costs to customers.

The DPU should evaluate its role in overseeing a system at significant risk of customer attrition due to policy actions outside of the DPU's control and competitive market forces. The DPU should thoroughly evaluate what a rightsizing transition would entail. The DPU should also evaluate its role as the regulator for both the gas distribution system and the electric distribution, particularly as different competitive modes of gas system exit (e.g., whole building electrification versus non-pipeline fuel hybrid arrangements) have significant implications for the electric distribution system. This is especially important as over half of gas customers are served by a different utility (see attached report on Estimated Electrification-Driven Utility Changes in Customers and Sales in Massachusetts).

Comment 3: The LDC's Study Had Significant Limitations That Undermine the Utilities Proposed Strategies

The Study Assumes Levels of Bioenergy Allocation to RNG That May Not Be Available or Their Prioritization to Heat Will Constrain Efforts to Decarbonize Other Sectors

While the allocation of bioenergy resources to RNG for building heat *could* decarbonize the Massachusetts building sector, it isn't the most optimal use of these resources for achieving global net zero emissions. Due to limited feedstocks and competing uses of bioenergy resources, heating decarbonization policy should not rely on high levels of renewable natural gas and not seek to prioritize renewable natural gas for heat.

- ❖ The attached working paper on *Challenges Associated with the Use of Renewable Fuels for Large-Scale Building Decarbonization* provides a detailed review of bioenergy availability

Broad "clean heat" policies should be favored over narrow "clean gas" policies. California's transportation-focused Low Carbon Fuel Standard and emerging clean heat standards in various states should be viewed as exemplars as they promote optionality. Narrower policies that set specific emissions intensities for pipeline gas – akin to the federal renewable fuel standard – will be more costly and less likely to succeed.

The Importance of the Gas Distribution System as a Regional Energy Asset is Overstated and Customer Attrition Risks Are Not Sufficiently Evaluated

The claimed benefits of maintaining a low-throughput gas system are overstated by the utilities because a significant portion of the emissions and economic benefits observed in the Hybrid Electrification Scenario stems from the hybridization of oil heating systems exclusively in this scenario – a modeling choice that is agnostic to the gas system.

Further, the application of hybrid heating strategies that apply non-pipeline fuels such as propane or biomass pellets to current gas-connected buildings could achieve some of the same benefits without the need for a gas distribution system. along with its significant replacement and O&M costs.

Finally, the utility's study does not sufficiently address issues surrounding customer attrition. As noted above and in an attached working paper, increasing alternatives to pipeline gas will erode the customer and sales base of gas. This will have significant consequences for the transition.

- ❖ The attached working paper *Assessment of Proposed Hybrid Heating Strategies* provides a detailed critique of the analyzed hybrid scenario and discusses non-pipeline hybrid strategies that may (1) underlie a market-driven customer exodus; and, (2) could be used to tactically decommission parts of the gas system with minimal customer impacts.
- ❖ The attached working paper on *Estimated Electrification-Driven Utility Changes in Customers and Sales in Massachusetts* illustrates the potential change in the utility thermal customer base under deep electrification.

The Study's Investigation into Electricity Sector Impacts, Decommissioning Strategies, and Building Electrification Strategies Was Superficial

This criticism focuses mostly on the study's overall scoping and design, rather than the study itself.

The study did not evaluate potential electricity-supply side strategies for managing the electricity demand needs of deep electrification.

The study's assessment of pipeline decommissioning was lackluster and can be summarized as "*more research is needed*". This is unfortunate as this study was an opportunity for the utilities to answer the question: "if the pipeline system did need to be decommissioned, how could it be done most cost-effectively?" This omission of diligence calls into question the conclusions drawn from the Targeted Electrification and 100% Decommissioning Scenarios.

A more robust understanding of building decarbonization pathways strategies is needed to evaluate the tradeoffs between whole building and hybrid electrification strategies.

The Study Largely Ignored Methane Leaks

The utility-owned pipeline distribution system and building (behind-the-meter) gas lines and appliances are a source of methane leakage, which has a significant and near-term climate impact. Recent efforts to reduce this lost and unaccounted for natural gas have not resulted in substantial changes in methane leaks. A significant amount of methane is evolving from behind-the-meter gas infrastructure within the buildings.

Alternative Proposals

The 20-80 investigation is an outliner in state efforts to decarbonize heat. Most states that have focused on building sector decarbonization have adopted or are moving to adopt a *clean heat standard* that offers regulated entities and customers significant flexibility in emissions mitigation pathways. However, such standards themselves are not on their own sufficient to achieve an equitably managed transition.

Need for a regulatory innovation period

To find the right regulatory structure to meet the Commonwealth's net zero emissions mandate, change is required. Under normal circumstances, regulations are used to maintain safety, reliability, and affordability. In this moment of inflection, we instead need an innovation framework, with conventional restrictions relaxed, pilots and pivots welcomed, and the door to alternate pathways open.

In this Innovation Phase, 'failure' is expected but constrained in scale, to allow each to be a key learning. Each potential pathway is evaluated with the consistent metrics of safety, reliability, affordability, security, emissions, and equity, with pathways that fail being eliminated.

To allow for innovation, iteration, and to learn how best to move forward with lower risk, we suggest a regulatory innovation phase until 2030 with annual reporting and reassessment. During this time period, the gas utilities are permitted to pilot not just an array of technologies and pathways as suggested by the consultants, but also to pilot their own evolution into non-emitting thermal utilities, tactically deploying multiple pathways and technologies across their territories.

Establish a Framework for the Evaluation of RNG Projects

Such a framework should evaluate whether or not RNG is the most cost-effective mitigation strategy for both the ratepayer and the renewable feedstock being used to generate the RNG.

Thermal Utilities

Allow gas utilities to make, distribute, and sell thermal energy - this change to the statutory definition of our gas companies in Chapter 164 of the general law is necessary to allow these utilities to attempt to meet the GWSA. They are currently mandated to sell what cannot meet the Commonwealth's emission mandates.

Develop a framework for the targeted retirement of leaky infrastructure currently covered by the GSEP program.

Obligation to serve can be met through the provision of thermal energy - while commented on in Section 92 of Chapter 164, this obligation appears to be codified within the Department's existing LDC customer contract language. It can be updated by the Department to define a continuation of service as inclusive of thermal service upgrades that meet the states' emissions mandates and that continue an equal or better level of safety, reliability, affordability, security, and equity.

Merged gas/thermal rate base - All customers served during this regulatory innovation phase remain a single rate base regardless of thermal technology or service received (i.e. whether supplied through gas or non-emitting thermal method). This merged rate base allows stabilization of the rate base and revenues by allowing gas customers to be transitioned to other technologies while still remaining in the same rate base. The stabilization of rate base and revenues will reduce impacts on affordability and equity as our state determines future categorization and regulations around technologies and services. All thermal infrastructure installed can be amortized over its expected lifetime, the same as gas infrastructure is now.

Issue an RFP for Thermal Tactical Transition Tool - In order to most efficiently and safely rightsize the gas infrastructure for the future demand and rate base, a data-based decision-making tool is needed to find thresholds for gas mains where possible to be transitioned to non-emitting thermal infrastructure. Some of the potential data to be used might include potential avoided costs, energy use, local geology, environmental justice neighborhoods, etc. A recent request for proposals (RFP) in California requested the development of a similar tool to ensure economic and equitable electrification.

Tactical Thermal Transition Study Working Paper: Challenges Associated with the Use of Renewable Fuels for Large-Scale Building Decarbonization

Michael Jay Walsh, Ph.D.[1] *and Jonathan Seth Krones, Ph.D.*[2]

Working Paper Draft: May 6, 2022

Highlights

- Most buildings in the Northeast are heated with either fuel oil, natural gas, or propane. "Drop-in" renewable analogs can be produced via several existing and emerging technologies, providing potential pathways to decarbonizing building heat.
- Historical efforts to develop renewable fuel technologies, notably in the transportation sector, were hampered by the rapid emergence of battery electric vehicles and various constraints on the production of renewable fuels.
- Renewable fuels will cost more than their fossil fuel counterparts. Heating with renewable fuels will likely be more expensive than most electric (heat pump) heating applications on an operating expense basis.
- New England states are unlikely to have a sustainable supply of bioenergy resources to meet current gas demands. For example, anaerobic digestion of Massachusetts' organic wastes would only yield approximately 5% of the state's existing natural gas demand.
- Sustainable bioenergy resources beyond New England are available for import but are also limited. These resources are essential for decarbonizing hard-to-electrify sectors such as aviation and shipping. They are also expected to be necessary for facilitating carbon dioxide removal – an essential component of net zero strategies. The dedication of bioenergy resources for building heat will compete with these uses. Reliance on energy imports has economic tradeoffs with strategies that leverage local capital investment in heat pumps and buildings to capture ambient heat.
- Heat pump heating can use five times less renewable electricity than needed to generate and use electricity-derived heating fuels.
- Ultimately, renewable fuels will likely have important niche roles in building sector decarbonization, but their application will be limited.

Guidance for Decision Makers

- Due to limited feedstocks and competing uses of bioenergy resources, heating decarbonization policy should not rely on high levels of renewable natural gas and not seek to prioritize renewable natural gas for heat.
- Broad "clean heat" policies should be favored over narrow "clean gas" policies. California's transportation-focused Low Carbon Fuel Standard and emerging clean heat standards in various states should be viewed as exemplars as they promote optionality. Narrower policies that set specific emissions intensities for pipeline gas – akin to the federal renewable fuel standard – will be more costly and less likely to succeed.

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[2] Jonathan Krones is a Visiting Assistant Professor at Boston College.

- Waste-to-energy projects should assess the potential cost and emissions tradeoffs between alternative energy strategies such as pipeline injection, renewable electricity generation, liquid fuel production, and carbon sequestration.

Background & Context

Heating fuels such as natural gas and heating oil can be replaced with analogous fuels produced from biological, waste, and other non-fossil-based feedstocks. Such "drop-in" fuels have the advantages of (1) being able to immediately decrease the greenhouse gas (GHG) emissions intensities of existing processes without requiring early retirement of either end-use (e.g., furnaces & boilers) or distribution assets (e.g., gas pipelines), and (2) not needing the heating system upgrades necessary for electrification. Indeed, these "decarbonized" fuels are already used in niche applications where favored by economics, including agriculture and wastewater treatment. In both instances, waste feedstocks are converted to fuels to satisfy on-site energy needs. Climate-focused regulations such as the federal Renewable Fuel Standard (RFS) and the California Low Carbon Fuels Standard (LCFS) have also promoted the use of decarbonized fuels in the transportation sector with mixed results.

Decarbonized fuels are currently playing a limited role in the building sector. Applications include **biodiesel** blended with fossil heating oil, heat from combusted **biogas** – generated in landfills and anaerobic digestors – beneficially utilized in nearby buildings, and some examples of **pipeline injection of renewable natural gas (RNG).** Policies have been proposed that aim to vastly increase the production and consumption of decarbonized fuels for use in the building sector. Still, significant questions remain as to the feasibility of these plans:

- What are the realistic short- and long-term costs associated with decarbonized fuel production and use?
- How much feedstock is available, where is it located, and is it secure over the long-term, given competing uses and environmental policies?
- Are decarbonized fuels the best use of renewable energy resources from a life-cycle energy perspective?

The answers to the above questions will determine the ability of decarbonized fuels to reduce building sector emissions meaningfully.

As part of the Massachusetts Department of Public Utilities Docket #20-80, a consultant (E3) for the Local Distribution Companies (LDCs) analyzed several scenarios illustrating possible pathways for the evolution of pipeline gas delivery in Massachusetts. Each of these scenarios relied – to varying degrees – on pipeline delivery of RNG to meet decarbonization targets. However, their study did not adequately address the questions posed above. Addressing these questions is essential to ensure that gas-dependent assets are not locked in under the questionable assumption that sufficient supplies of RNG will be available in the future.

This assessment evaluates the potential of decarbonized fuel production pathways to support building sector decarbonization by synthesizing current knowledge in the context of the gas transition in Massachusetts and the Northeast and by examining an analogous transition in the transportation sector.

Overview of Heating Fuels

The three most common fuels used for heating buildings in Massachusetts are pipeline-delivered natural gas (mainly composed of methane), fuel oil, and propane.[3] A small percentage of homes in Massachusetts are also heated with wood. What type of fuel a building uses depends on fuel availability, costs of both the fuel and the end-use equipment, and desired end uses. Figure 1 compares the heating sources of households in Massachusetts, the six-state region of New England, and the U.S. as a whole. The significant difference between Massachusetts and its regional neighbors is the increased reliance on pipeline natural gas in the Commonwealth vs. truck-delivered fuel oil and propane in other New England states. Data for the entire U.S. show a much smaller dependence on fuel oil in favor of electricity – the heating source of choice for much of the warmer portions of the country.

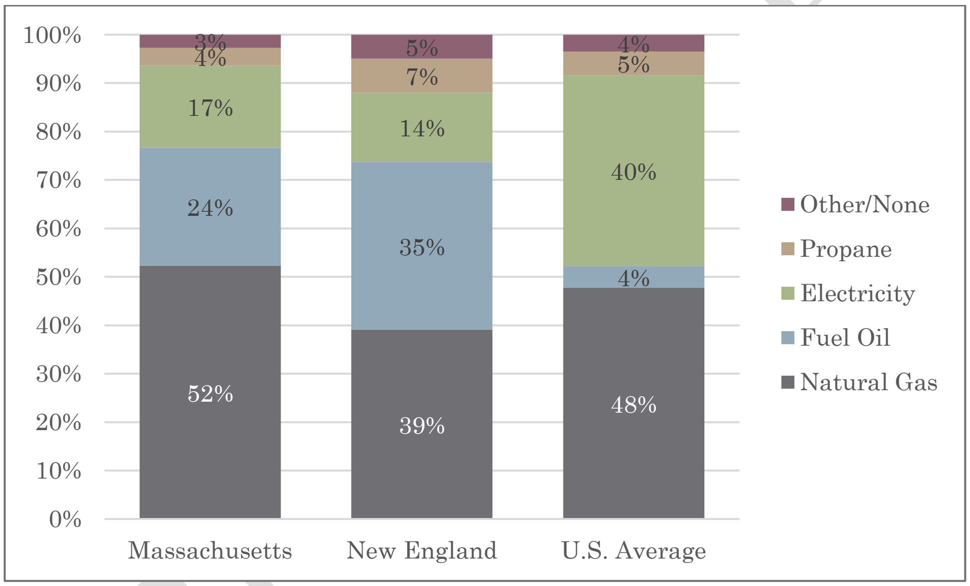

FIGURE 1. THE ENERGY SOURCE USED FOR HOME HEATING (SHARE OF HOUSEHOLDS) IN MASSACHUSETTS, NEW ENGLAND, AND THE ENTIRE U.S., 2019. "OTHER/NONE" INCLUDES WOOD FUEL. SOURCE: U.S. CENSUS BUREAU. 2019 AMERICAN COMMUNITY SURVEY 5-YEAR ESTIMATES, TABLE DP04: SELECTED HOUSING CHARACTERISTICS, HTTPS://DATA.CENSUS.GOV/CEDSCI/TABLE?G=0400000US09,23,25,33,44,50&TID=ACSDP5Y2019.DP04

A summary of decarbonized fuels discussed in this assessment is presented in Table 1. As was made clear by the U.S. Department of Energy's 2016 Billion-Ton Report, there is a large and diverse set of feedstocks, processing pathways, and end-uses for such fossil fuel replacements.[4] However, it is essential to note that all the decarbonized fuels are currently and will continue to be more expensive than either natural gas or their other fossil fuel equivalents for reasons discussed in the subsequent section. For more background and context on heating fuels and pathways for their decarbonization that range from being long-established to not-yet commercially available, see Appendix A.

[3] Electric resistance heating is also standard despite its relatively higher costs. Electric heat pumps are rapidly growing in market share but have yet to reach the scales of the fuel-heated and electric resistance homes.

[4] U.S. DOE. 2016. 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy. https://www.energy.gov/eere/bioenergy/2016-billion-ton-report. Accessed March 29, 2022.

TABLE 1. DECARBONIZED FUELS PROPOSED FOR BUILDING DECARBONIZATION

Fuel Class	Fuel Product(s)	Example Renewable Production Processes	Application
Pipeline gas (natural gas, methane)	Renewable natural gas (RNG) Synthetic natural gas (SNG)	Anaerobic digestion of organic waste Landfill gas Gasification of biomass Sabatier methanation reaction of captured carbon and hydrogen	RNG/SNG can be injected into the gas pipeline.
LPG (e.g., propane)	Renewable or synthetic LPG Dimethyl Ether (DME)	Gasification of biomass Production from renewable hydrogen and renewable methane. A byproduct of methanol to gasoline or Fischer-Tropsch production of longer-chain oils	Renewable LPG can replace petroleum LPG and methane in end-use equipment with modest modifications.
Oil	Biodiesel	Transesterification of bio-oils using methanol/ethanol Hydrogenation of bio-oil Pyrolysis or hydrothermal liquefaction of biomass	Depending on the blend, it could replace some existing oil uses with modest modifications to end-use equipment.
Hydrogen	Hydrogen	Electrolysis with renewable energy Steam methane reforming with carbon capture and storage Nuclear (electrolysis) Gasification of biomass	Blend into existing pipelines up to 20%. Higher blends require upgrading pipelines and end-use equipment.

Opportunities and Challenges of Decarbonizing Heat with Low Carbon Fuels

Decarbonization plans that hinge on replacing fossil fuels with decarbonized fuels, particularly renewable natural gas (RNG) and synthetic natural gas (SNG), must grapple with the fact that large-scale production of these fuels for pipeline injection does not currently exist. This is not necessarily a problem; after all, setting a clear policy is intended to create favorable conditions for investment in and scale-up of these technologies. These fuels are also significantly more expensive than their fossil fuel equivalents. While it is likely that decarbonized fuels will always be at least nominally more costly than fossil fuels,[5] the widespread adoption of such fuels relies on the emergence of a scenario where economies of scale, technology learning curves, innovation, and public incentives can bring down the cost to bearable levels. However, decarbonized fuels are not just competing with fossil fuels as a building heating technology; they also compete with electrification, specifically, heat pumps for space and water heating and induction stoves for cooking.

Interestingly, this is not the first time that an effort to decarbonize fuel came up against electrified alternatives. Challenges from transportation biofuels and two decades of intense innovation pressure offer lessons applicable to heating fuels today.

Historical precedent: Transportation Biofuels

Transportation decarbonization policies like the California Low Carbon Fuels Standard (LCFS) and the federal Renewable Fuels Standard (RFS) were designed to stimulate the growth of the renewable fuels industry, specifically advanced cellulosic ethanol. This fuel has a much broader feedstock base

[5] Numerous studies in recent years have quantified how fossil fuel pricing benefits from massive economic externalities, including government subsidy of various forms and environmental impacts whose costs are not entirely borne by the fuels (e.g., oil spills, respiratory disease, and the various effects of climate change). Biofuels and RNG/SNG are unlikely to receive a similar public subsidy and, by their nature, internalize more of their environmental costs, which contributes to their competitive disadvantage compared with fossil fuels.

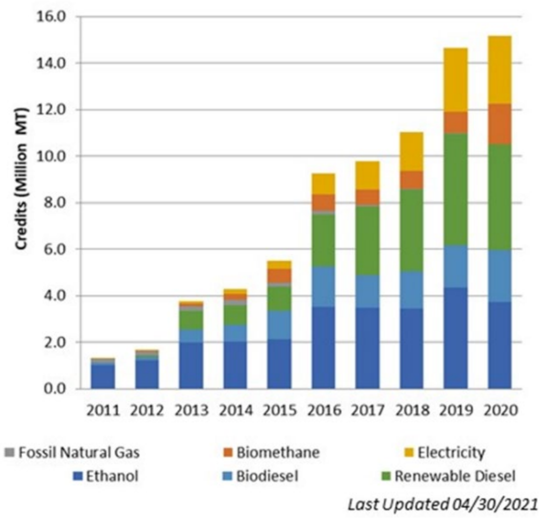

FIGURE 2. CALIFORNIA LCFS CREDITS BY FUEL TYPE. SOURCE: FOOTNOTE 7.

and a more robust case for life-cycle GHG emissions benefits than conventional corn-based ethanol.[6] After more than a decade of these policies, there has been little to show as vehicle electrification has emerged instead as the primary driver of transportation sector emissions reductions. Electric vehicle credits are now the fastest-growing contributor to the LCFS's targets (Figure 2)[7] – a trend that will likely continue depressing prices for and disincentivizing other LCFS-qualified fuels. The Federal RFS program has languished as the development of advanced biofuels has failed to meet technical and cost milestones. Despite vehicle electrification's apparent dominance in reducing transportation sector emissions from passenger and light-duty transport, renewable fuels will likely still play an essential role in decarbonizing hard-to-electrify modes such as heavy-duty trucking and air transport.

The transportation biofuels industry is an example of a sector that could not deliver on its promises of technological progress. Even with significant support from government research investments, the RFS, and private capital, this industry was challenged on two key fronts: competition from battery-electric vehicles (BEVs) and competing uses for biofuel feedstocks.[8]

The rapid decline in the cost of BEVs reduced the need to decarbonize many transportation fuels and created a product that emerged with lower lifetime costs and higher perceived value compared to fuel-consuming vehicles. The automobile industry has responded to this trend and has since started an accelerating shift toward BEVs. The biofuels industry failed to produce the necessary performance improvements to reduce costs. One reason for the lack of improvements was that the complicated nature of large and capital-intensive biorefineries resulted in a slower rate of technological learning. Like those that yield batteries, manufacturing-based processes allow faster iteration cycles, leading to a more rapid pace of technological progress and cost declines.

Another reason for poor performance improvements was the conflicting effects of size and scale in biorefinery operations. As with many processes, achieving greater economies of scale can lead to significant cost savings. This economic logic underpins Tesla's Gigafactory lithium-ion battery production strategy. Biorefineries require agricultural inputs, often from the land surrounding the facility. As refinery capacity increases, so too does the required cultivation area and transportation distances, the cost of which does not generally follow the same scaling patterns. Eventually, it becomes too expensive to provide increasing volumes of raw materials to the refinery. Battery

[6] Julie Witcover. December 2021. What Happened and Will Happen with Biofuels? Review and Prospects for Non-Conventional Biofuels in California and the U.S.: Supply, Cost, and Potential GHG Reductions. National Center for Sustainable Transportation.
[7] California Air Resources Board LCFS Data Dashboard: https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard (Accessed March 2022)
[8] Witcover also assigns blame to a drop in oil prices and policy architectures that did not effectively differentiate between conventional ethanol and cellulosic ethanol, leading the former to tend to crowd out investment in the latter. However, she also acknowledges repeated technical failures and poor scaling as fatal flaws.

production follows the conventional way, continuing the long tradition of satisfying the growing demand for raw materials through increasingly intensive mining operations.[9]

The second headwind challenging transportation biofuels production has been competing uses for biofuel feedstocks (e.g., corn, soy). This dynamic was popularly expressed in the food vs. fuels debate of the late 2000s but ultimately is a result of large-scale bioenergy having a significant land, water, nutrient, and climate impact. While using waste feedstocks would not have such effects, there are insufficient amounts to meet the demand of the whole transportation sector, to say nothing of all the other potential avenues for bioenergy and bioproducts.[10] Any available feedstocks have the potential to deliver higher value in other uses – aviation or bio-derived chemicals and materials – than in the low-margin vehicle fuel sector.

The dynamics experienced by transportation biofuels in the past two decades find similarities in today's debates around heating fuels, particularly pipeline injection of RNG and SNG. In the following few sections, we detail some of these parallels in areas including production costs and realistic learning curves; the availability of and competitive uses for fuel feedstocks; and the inherent energy balance of the technologies, especially in a transition to a renewables-dominant electric grid.

Production costs

The attractiveness of decarbonized fuels is mainly based on their purported economic competitiveness compared with alternative carbon abatement pathways. After all, in this scenario, gas providers can simply swap out the fuel without building occupants making any changes to either end-use technology or behavior. At present, the production costs of RNG are significantly higher than those of natural gas, but it is produced for pipeline injection in relatively small quantities. What might the charges be at scale?

A 2019 study by ICF for the American Gas Foundation modeled production costs of RNG from anaerobic digestion and thermal gasification.[11] They concluded that, given realistic assumptions about energy, infrastructure, and financing costs at scale, RNG and SNG can be expected to cost between double and ten-times today's price of natural gas[12], depending on the feedstock and production pathway.[13] The lower-cost options include RNG produced from biogas, followed by gasification of agricultural and forestry residues, with power-to-gas systems at the high end, even without incorporating the carbon dioxide (CO2) capture costs.

According to the EPA, the costs of RNG produced from biogas are primarily driven by the need to (1) upgrade biogas to pipeline quality (i.e., concentrating methane and removing CO_2 and other

[9] Lithium mining is not always straightforward, mainly when lithium is extracted from brines. Intensive mining operations and reliance on environmentally- and socially-exploitative practices to source battery materials are significant challenges facing the BEV industry.
[10] US DOE, 2016.
[11] AGF & ICF. December 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment. https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf. Accessed March 21, 2022.
[12] Before the energy crisis sparked by the Russian invasion of Ukraine. It can be anticipated that prices will eventually decline to at or above recent levels and stabilize in the long run.
[13] The 2021 average Henry Hub natural gas spot price was $4.06/MMBtu, nearly double the previous year's price but lower than what the 2022 value is expected to be. Source: U.S. EIA. March 2022. Short-term energy outlook. https://www.eia.gov/outlooks/steo/report/natgas.php. Accessed March 21, 2022.

impurities) and (2) construct pipeline interconnections.[14] While both costs are affected by economies of scale, the experience with transportation biofuels suggests fundamental limits to facility size defined by the costs of collecting distributed feedstocks. It is possible that with technology improvement, the expenses of RNG upgrading may come down modestly below the ICF model. Still, it is hard to see a clear pathway for pipeline-injected RNG to compete with fossil methane without substantial government subsidy or mandate.[15] It is also equally likely that the RNG industry will not be able to achieve even the cost reductions anticipated by the ICF model, similar to the case of cellulosic ethanol in the transportation biofuels case.

On the other hand, the economic case for using biogas directly in combined heat and power (CHP) systems (i.e., not converting it to RNG quality), either on-site or close to the generation site, is evidenced by the numerous biogas projects in existence. Here, operators can save considerable costs by using a CHP system designed to work with the chemical composition of biogas and avoid complex and long-distance pipeline interconnection. Even if natural gas utilities could pay enough for a landfill, say, to sell its biogas for the pipeline market, the landfill operators would need to find their source of decarbonized heat.

The forecast for gasification of organic residues is highly uncertain and strongly capacity dependent. This would suggest that some of the scale limitations experienced in the case of the biofuels are applicable, and there are severe limitations in the cost competitiveness of this source of RNG/SNG.

The production costs of power-to-gas SNG vastly exceed those of RNG. ICF's models predict that they will stay high for decades to come, even with the sharp decreases in the costs of electrolysis, methanation, and increased system efficiency the models assume. For this technology to scale and become economical, both cost declines in equipment and the need to maintain high-capacity factors in equipment use will be needed. Some SNG technologies are likely to follow the learning curves experienced by solar and wind technology, that is, substantial reductions with scale, but the industry is presently very far from their realization. Carbon-neutral SNG that relies on distributed air capture (DAC) of CO_2 is further away from maturity.

The primary competitor for decarbonizing building heating, electrification, is also in a nascent stage, at least in the Northeast. The high cost of whole home electrification is currently a barrier to its adoption. Installation is costly due to an inexperienced HVAC industry and partly due to the retrofit challenges of the old building stock. Additionally, electric heating costs with heat pumps may, and certainly will during colder days, exceed the costs of gas-based heating. But just as BEVs have rapidly decreased in price and as consumers have realized the significantly reduced operating costs of EVs, heat pumps, other electric technologies, and innovative system designs will likely follow similar technology learning curves.

Feedstock availability & competing uses

A second risk to a decarbonized fuels strategy is ensuring sufficient and continuing availability of feedstocks. There is an ample but limited supply of food waste, wastewater treatment sludge, manure, forestry and agricultural residues, and even energy crops that can be converted into RNG, biodiesel, or DME (dimethyl ether, a decarbonized replacement for propane or liquefied petroleum gas). Each feedstock has competing uses, including other energy projects and non-energy applications. Some of these sources are themselves subject to different environmental regulatory

[14] U.S. EPA. July 2020. An Overview of Renewable Natural Gas from Biogas. EPA 456-R-20-001. https://www.epa.gov/sites/default/files/2020-07/documents/lmop_rng_document.pdf. Accessed March 20, 2022.

[15] The LDC's common regulatory framework proposes a clean fuels standard for pipeline gas delivery that would mandate an increasing amount of RNG blending over the next three decades.

pressures, leading to the potential conflict between, for instance, waste reduction and renewable energy generation. Additionally, there is a geographic disparity between sites of feedstock generation and sites of likely demand for RNG, especially in the Northeast.

Feedstock availability

According to a 2019 ICF study for the American Gas Foundation, there are sufficient resources in the United States to produce between 1,660 trillion Btu (TBtu) and 4,510 TBtu of RNG for pipeline injection annually by 2040. Total annual natural gas consumption averaged 30,500 TBtu between 2016 and 2021. Even just the quantity of natural gas consumed by residential consumers (4,860 TBtu) exceeds the most optimistic of ICF's estimates. **The ICF study assumes that the bulk of the country's organic waste bioenergy resource is dedicated to RNG production, while the 2016 Billion-Ton Study from the U.S. DOE makes clear that numerous high-value applications of this resource – such as the production of decarbonized liquid fuels for hard-to-electrify sectors like air travel – will be more of a priority than RNG**.[16]

The gulf between available resources and total methane demand in Massachusetts is even more significant. There are currently ten landfill gas (LFG) collection systems, eight agricultural waste digesters, one food-waste digester co-located with an LFG project, and six municipal wastewater treatment plants in the Commonwealth that produce and utilize biogas (Figure 3).

The LFG sites generate approximately 5 TBtu of methane annually,[17] representing about 1% of Massachusetts' methane consumption.[18] The potential for additional production is modest, with the most economically viable projects being implemented. The EPA has identified four low-yield sites as "candidates" or having "future potential." Nevertheless, this resource is phasing out. Massachusetts intends to close all of its landfills by the end of this decade. Still, as organic matter decays in the landfills, the annual yield of methane will decline measurably over the next couple of decades, approaching a fraction of today's production.[19]

[16] U.S. DOE 2016.
[17] Authors calculations based on EPA data.
[18] In 2020, Massachusetts consumed approximately 400 TBtu of natural gas, 125 TBtu of which were in the residential sector. Source: U.S. EPA. February 2022. Natural gas consumption by end-use. https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMA_A.htm. Accessed March 21, 2022.
[19] Jonathan Krones. December 2020. Non-energy sector report: A technical report of the Massachusetts 2050 Decarbonization Roadmap Study. https://www.mass.gov/doc/non-energy-sector-technical-report/download. Accessed March 21, 2022.

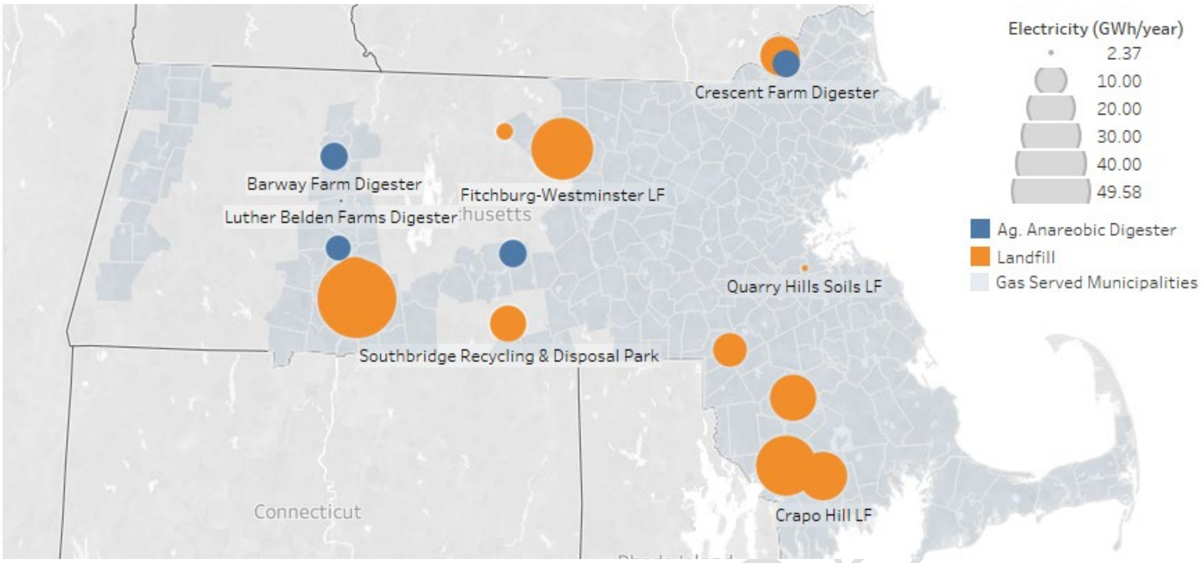

FIGURE 3. ELECTRICITY GENERATION AT LANDFILLS AND AGRICULTURAL ANAEROBIC DIGESTORS IN MASSACHUSETTS AS REPORTED TO THE EPA'S LANDFILL METHANE OUTREACH PROGRAM[20] AND EPA'S AGSTAR LIVESTOCK ANAEROBIC DIGESTER DATABASE[21].

On the other hand, the anaerobic digestion of wastes has the potential to grow significantly. Agricultural digestors currently produce approximately 0.4 TBtu of methane annually from the waste generated by a tenth of the Commonwealth's cattle. Food waste is increasingly diverted to digesters on farms and municipal wastewater treatment plants. Over a million short tons of food waste are generated annually in the Commonwealth, the energy equivalent of 3.6 TBtu of methane. This potential assumes no reduction in food waste generation or diversion to composting or other waste-to-energy technology such as those that would yield liquid fuels.

There is an environmental policy tension between waste reduction goals and renewable fuels goals. Motivations for reducing waste generation are not limited to the downstream ecological impacts of landfill and incinerator disposal, including anaerobic decomposition of organic wastes in landfills, which releases methane even if an LFG capture system is in place. Most LFG systems are far from 100% effective. **Waste reduction also has upstream benefits, often avoiding resource-intensive production of items that ultimately are not used. As of now, there is limited evidence that the two environmental policies—waste reduction and renewable fuels—have yet interacted, but it is not difficult to imagine a future in which the continued and avoidable generation of food waste is necessary to satisfy heating demands, an absurd situation.**

An additional source of feedstock insecurity derives from the fact that to achieve any meaningful pipeline injection of RNG, Massachusetts gas companies would have to source their supply from surrounding states and, more likely, the agricultural heartland of the Midwest. Already accustomed to paying some of the highest energy costs in the nation, Massachusetts residents would likely be able to outcompete other states for access to the feedstock and fuel, but this is a zero-sum approach

[20] EPA. Landfill Methane Outreach Program Landfill and Project Database: https://www.epa.gov/lmop/lmop-landfill-and-project-database (Accessed March 2022).
[21] EPA. Livestock Anaerobic Digester Database: https://www.epa.gov/agstar/livestock-anaerobic-digester-database (Accessed March 2022).

to decarbonization. After all, it does little to address the climate risks to the Commonwealth if our decarbonization strategy makes it less likely that other regions meet their emission reduction goals.

Competing pathways

Numerous competing pathways exist for the ample but limited supply of biological feedstocks described in this assessment and illustrated in Figure 5.

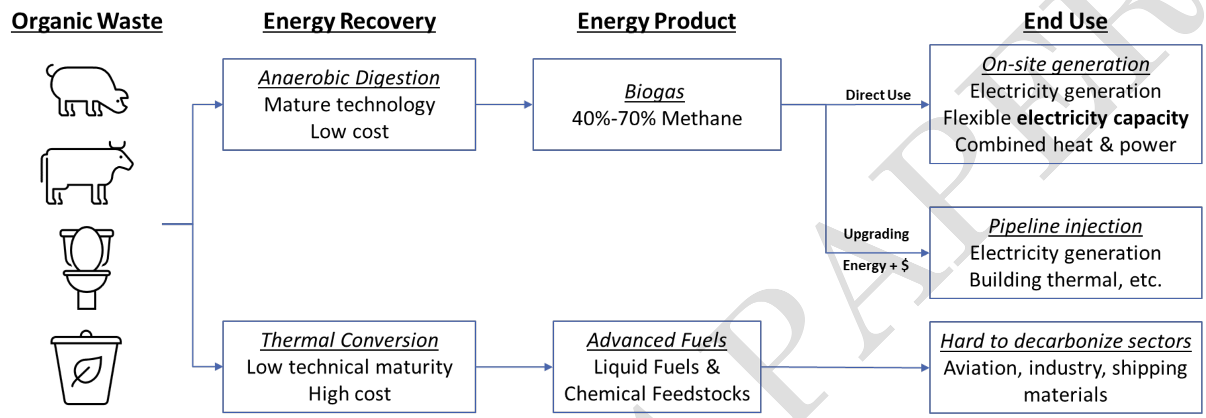

FIGURE 4. ORGANIC WASTE-TO-ENERGY PATHWAYS.

None of the Massachusetts LFG or anaerobic digestor sites inject RNG into the pipeline system.[22] Instead, the biogas produced is combusted on-site to generate electricity and, at some locations, co-generate heat. Biogas requires further processing to increase energy content and decrease contamination levels to be consistent with the natural gas transported by the pipeline system to be a drop-in replacement for natural gas. This energy-consuming purification and the interconnection with the gas grid can add cost to the project, and it is thus generally more economically favorable to burn this biogas onsite.

Given the difficulty in decarbonizing fuels, it is worth considering the tactical choice of allocating renewable gas to the pipeline system or combusting it onsite. So long as fossil methane gas is used in electricity generation, upgrading biogas for injection into the pipeline gas system – which supplies electricity generators and the building sector – provides little apparent mitigation and energy system value at a financial and energetic cost. While this may allow distinct entities that procure the injected RNG to claim an individual carbon reduction in their fuel use, it is an inefficient allocation of energy resources. Further, onsite electricity generation from biogas could be designed to be load-following – anaerobic digesters are often coupled with methane storage – and operate in a way that could support variable renewable energy systems.[23]

In some circumstances transporting RNG off-site can be advantageous, particularly in cases that can leverage CHP production. Combined with some level of renewable gas storage, such a resource could be coupled with electric heating systems. Such dual fuel approaches enable more optimal uses of energy resources. The bulk renewable energy system can provide sufficiently low-cost electricity for

[22] Liberty Utilities has proposed to convert an LFG-to-electricity facility into an LFG-to-RNG facility with pipeline injection. Petition of Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty for Approval of an Agreement to Purchase Renewable Natural Gas from Fall River RNG LLC and of the Liberty RNG Program. eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber/22-32
[23] In remote areas, this approach may require the upgrading of some electrical distribution systems, which may challenge distributed generation from biogas. Still, it could be coupled with utility-scale or agriculturally-integrated solar projects.

heating throughout most of the year. Still, when electricity supplies are low, biogas or RNG-based CHP systems can provide district heating at this point while generating electricity for onsite use or sales to the grid. If kept separate from the pipeline gas system, such applications may not require intensive purification.

In the long run, the production of other liquid fuels may be a more beneficial use of limited organic wastes than biogas production through anaerobic digestion. Advanced conversion processes (e.g., hydrothermal liquefaction or Fischer-Tropsch) can yield renewable liquid hydrocarbons for aviation or shipping – sectors that are much harder to decarbonize than building heating and electricity generation. While such technologies have been demonstrated in pilot projects, they will take some time to scale and achieve lower costs.

Finally, biomass-derived carbon sequestration is an essential element of net zero strategies. One widely accepted proposal, bioenergy electricity production with carbon capture and storage, has yet to be demonstrated as a scalable solution. In its absence, the utilization of organic wastes to create either biochar applied to soils or pyrolysis oil injected underground has emerged as potential mechanisms to facilitate durable carbon dioxide removal.[24] Some of these technologies may have lower carbon abatement costs than RNG, can result in carbon removal rather than reuse, and will undoubtedly compete for the same biomass feedstocks as RNG and other renewable fuels.

If these or other similarly durable carbon sequestration techniques were scaled up and demonstrated competitive performance, it would open up new, creative pathways for system-wide decarbonization. For example, it may be preferable to continue utilizing fossil fuels with biomass-derived durable offsets rather than using the same biomass to produce RNG.[25] Since RNG procurement contracts are expected to be long-term and integrated into supply rates, this may saddle ratepayers with higher costs than they could receive through competitive procurement.[26]

A specific waste-to-energy strategy may be favored by short-run and long-run locational factors that should consider local energy resources and needs. For example, electricity generation may be important in some rural areas that are seeing increasing electricity demand. Alternatively, pipeline injection of RNG may help alleviate the end of the pipeline constraints in such areas. Any assessment should take an integrated energy perspective. For example, if a landfill gas electric generator was considering shifting to RNG for pipeline injection, it makes little sense to extend additional energy for pipeline injection to alleviate gas constraints if nearby gas electricity generation electricity will have to make up for lost generation.

Energy balance

The energy balance of the fuels and other heating options is a final analytical lens that illuminates the risks of relying on decarbonized fuels. Do these fuels make the best use of a limited amount of renewable energy resources?

Electric heat pumps work by capturing and concentrating ambient heat from the air and ground and using it to heat a building. This feature underlies their ability to provide more heating services for

[24] See Charm Industrial for an example of this technology. Current sequestration costs are $600 per tonne of CO_2. https://charmindustrial.com/

[25] In net zero emissions energy systems, some utilization of fossil fuels is expected but would be needed to be coupled with carbon dioxide removal.

[26] This is similar to how recent community choice aggregation programs, which have been able to buy into new, cheap renewable contracts, have left electric utility supply programs being burdened with higher-cost historical contracts.

the same energy input than either combustion or electric resistance sources can. While its advantage shrinks but doesn't disappear, at colder temperatures, it does maintain a significantly higher efficiency than its alternatives,[27] especially considering the production energy losses in liquid fuels.

Fossil fuel and renewable fuel supply chains experience energy losses stemming from extraction/collection, processing, and delivery. In a low-carbon world, all the inputs to these processes must themselves be largely decarbonized. When producing a biofuel, some of the energetic value of that fuel is consumed to deliver it in a low carbon manner. With synthetic electrofuels (SNG), clean electricity (e.g., solar, wind, hydro) would be needed to generate the fuels, and the electrolysis and methanation steps incur significant energy penalties. Using the renewable electricity directly in a high-efficiency electric heat pump may be preferable instead.

Figure 6 compares three heating pathways powered by renewable electricity: an electric heat pump, hydrogen fuel cell heating, and an SNG combustion boiler. [28] The analysis shows that even with relatively high-efficiency processes, using renewable electricity to power electrolysis and methanation in a power-to-gas system cannot overcome the fundamental advantage of an electric heat pump. The advantage of heat pumps grows if direct air capture is used to source carbon dioxide. RNG would perform better in this analysis than SNG. Although biogas can be produced with minimal energy inputs in anaerobic environments, upgrading it to RNG for pipeline injection is again an energy-losing step.

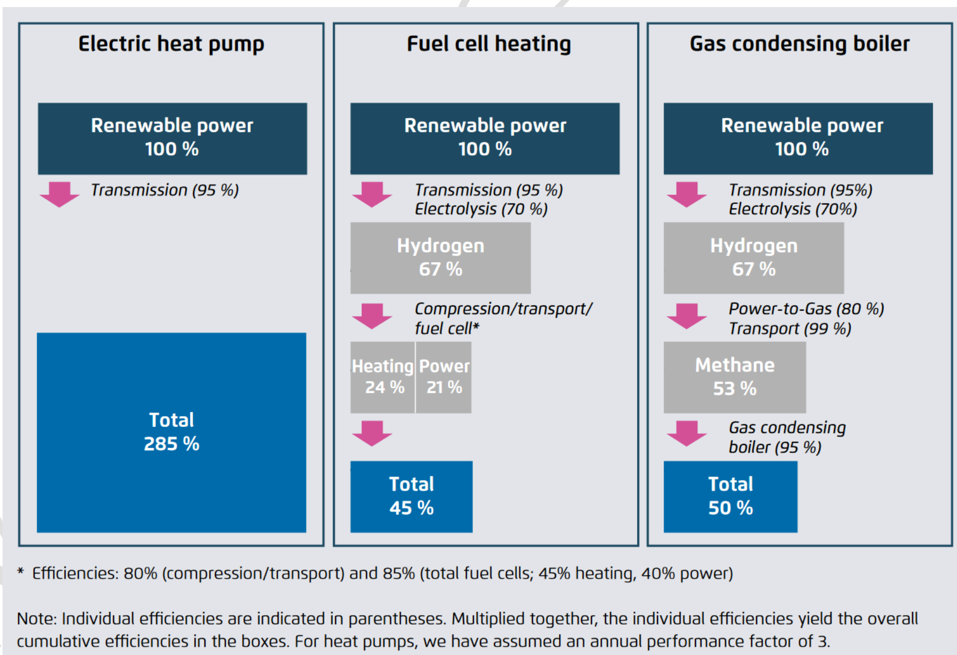

FIGURE 5. INDIVIDUAL AND OVERALL EFFICIENCIES FOR DIFFERENT HEATING SYSTEMS, STARTING FROM RENEWABLE ELECTRICITY. SOURCE: AGORA VERKEHRSWENDE, AGORA ENERGIEWENDE, AND FRONTIER ECONOMICS (2018).

[27] The "efficiency" of a heat pump is more accurately called its "coefficient of performance" and can be as high as 3 or 3.5 in good conditions, meaning for every unit of electricity put into the device, you get three or more units of heating energy services out. This is because heat pumps do not produce heat; they simply move it around.

[28] Agora Verkehrswende, Agora Energiewende and Frontier Economics. 2018. The Future Cost of Electricity-Based Synthetic Fuels.

A final example of the usefulness of energy analysis in determining the best allocation of scarce energy resources examines forest residues. Under aggressive decarbonized fuel planning, forestry residues will be used as feedstock for thermo-chemical gasification and conversion to RNG, liquid fuels, or DME, partially for heating buildings. However, these processes are likely to incur high energy losses. A reasonable alternative would be to convert forestry residues to wood pellets for use in a pellet furnace. This process also has energy inputs: transportation, drying, and pelletizing, but avoiding the significant thermo-chemical processing steps that will allow much more of the chemical energy of the wood to be converted to useful heat in the home.

Conclusions

While bioenergy resources are likely to play an essential role in decarbonizing some heating needs, overreliance on bioenergy poses significant risks related to affordability and achieving climate goals. Future analysis should highlight the tradeoffs associated with various renewable fuel pathways in local and national contexts.

Policymakers should consider the constraints in bioenergy resources when developing regulations. Policies that seek to decarbonize heat are likely to achieve more climate and cost-optimal outcomes than policies that seek to decarbonize fuel supply. Such approaches are consistent with the California LCFS and emerging Clean Heat Standard legislation in several states. This allows for a wide range of options (including electric) in sectoral decarbonization strategies.

Appendix A: Background on renewable fuels

Methane

Natural gas, a fossil fuel that is almost entirely made up of methane (CH_4), is typically considered the preferred or default home heating fuel due to its low cost and ability to be used for a variety of end-uses, including space heating, water heating, cooking, drying and aesthetic fireplaces. This "pipeline gas" is only available where settlement density permits its distribution via an underground pipeline. Methane has emerged as the lowest cost heating fuel due to: (1) technological advancements that have unlocked an ample supply of shale gas resources; and (2) economies of scale associated with the distribution of methane via underground pipe distribution systems operated by regulated utilities. There are two major pathways for decarbonizing this fuel: renewable natural gas (RNG) and synthetic natural gas (SNG).

Renewable Methane

Renewable natural gas (RNG) or renewable methane refers to methane that is produced from biological feedstocks, either through the anaerobic decomposition of organic wastes at landfills[29] and engineered anaerobic digesters or the gasification of solid biomass. The product of anaerobic decay is called "biogas," containing just 40-80% methane, the rest being a mixture of carbon dioxide (CO_2), water vapor, and other gases. Biogas requires additional processing and purification before it can be injected into the gas transmission and distribution pipelines, which can be called RNG. Gasification pathways are discussed in the SNG section below.

On-site use of biogas

Biogas is often used at the site of its production. Combustion of biogas in a combined heat and power (CHP) system can produce thermal energy for onsite use and electricity for onsite service or export to the grid. Biogas can be stored onsite and combusted during high heat or electricity demand periods.

[29] Often referred to as Landfill Gas (LFG)

Organic wastes are often co-located with wastewater and agricultural facilities with high energy demand, creating situations well-suited for anaerobic digestion, as illustrated by the example in Box 1.

Box 1: Deer Island Wastewater Treatment

One of the largest wastewater treatment plants in the country, Deer Island serves more than three million people and numerous businesses in eastern Massachusetts. Its distinctive array of 12 egg-shaped anaerobic digesters has become a visual landmark for those flying in and out of Boston Logan International Airport. The digesters receive sludge from the sewage treatment processes and convert it into biogas and fertilizer. The biogas is combusted on-site in a CHP plant, generating almost all of the heat and one-quarter of the electricity used at the facility.[30] While the digesters have sharply reduced the amount of fossil fuels required by the plant, it is notable that even given the large quantity of sewage sludge available, all biogas generated is consumed on-site, leaving no surplus for use elsewhere.

In the late 2010s, the Massachusetts Water Resources Authority, which operates Deer Island, explored the possibility of co-digesting food scraps with the sewage sludge.[31] While it was determined to be technically feasible and would have resulted in more biogas production on top of the benefits of avoiding landfill and incinerator disposal of organic waste, the plan was ultimately not pursued because of the challenges of trucking vast quantities of food waste to the facility were determined to be too great.

Pipeline-injection of RNG

Additional treatment, notably CO_2 removal, is necessary for purifying (also called "upgrading") the biogas to a methane concentration that can be injected into the pipeline and used as a drop-in replacement for natural gas. This purification to pipeline quality comes at energetic and financial costs compared to onsite uses of the biogas precursor.

Biogas production needs to be located near the pipeline network for gas pipeline injection. This may be infeasible for many rural agricultural production sites in the Northeast, but it can be accomplished with new infrastructure investments, as described in Box 2. Even if a farm with an anaerobic digester is located in a community served by gas, as some of the Commonwealth's are, the digesters themselves may be several miles removed from the distribution system requiring significant investment to make the connection.

Box 2: Pipeline injection of RNG

The first project in New England to actively inject RNG into the natural gas grid was launched in July 2021. Middlebury College (VT) partnered with Wellesley, MA-based Vanguard Renewables, Vermont Gas (now VGS), and Goodrich Family Farm to produce, transport, and use agricultural waste-derived RNG to supplement the college's biomass-based district heating system.[32] The facility is designed to make 140,000 Mcf per year of RNG from approximately 100 tons of manure and 165

[30] Cutler Cleveland, et al. 2019. Carbon Free Boston Summary Report. https://www.bu.edu/ise/research/reports-papers/carbon-free-boston-summary-report/. Accessed March 28, 2022.

[31] David L. Parry. 2014. "Codigestion Potential At Large-Scale Wastewater Treatment Facility," *BioCycle*. https://www.biocycle.net/codigestion-potential-at-large-scale-wastewater-treatment-facility/. Accessed March 28, 2022.

[32] Middlebury College Newsroom. July 21, 2021. Largest Anaerobic Digester in the Northeast Begins Production of Renewable Energy. http://www.middlebury.edu/newsroom/archive/2021-news/node/658771. Accessed March 22, 2022.

tons of other organic waste per day, including food waste from Middlebury and a local cheese processing facility.[33]

VGS offers the renewable attribute of this gas to other retail customers for a price of $12.425 per Mcf on top of the customer's base rate.[34] For comparison, the average cost of natural gas delivered to consumers in Massachusetts in 2019 was $14.72 per Mcf in the residential sector and $11.32 per Mcf in the commercial sector. [35] At this price, RNG far exceeds the cost of decarbonization via electrification for most building classes. As a bulk buyer, Middlebury will likely obtain a lower rate, use the gas for combined heat and electricity production, and avoid early retirement of its gasification plant as it pursues its 2028 goal for 100% renewable energy.

Synthetic natural gas

Synthetic natural gas (SNG) refers to methane produced by reacting hydrogen gas (H_2) with carbon dioxide (CO_2) and carbon monoxide (CO), a mixture known as "syngas."[36] There are two major process categories for producing synthetic natural gas: thermochemical gasification and power-to-gas.[37]

Several thermo-chemical processes have been used for nearly a century to convert coal to gas or liquid hydrocarbons via a syngas intermediary produced from the gasification of solid carbon. This process can be decarbonized by substituting coal with renewable biomass as a feedstock. However, the high temperature and pressure under which the process occurs require significant energy inputs, compromising the net energy output of thermochemically-derived SNG. Historically, coal or biomass gasification occurred in situations where pipeline distribution favored gas over solid fuels. Gas street lighting is an early example of this.

Power-to-gas usually refers to the production of hydrogen gas through the electrolysis of water. This hydrogen can then be reacted thermochemically or electrochemically with CO_2 to produce methane or liquid hydrocarbons. Carbon-neutral implementation of this pathway can be achieved by using hydrogen produced from zero-emissions electricity (renewables, hydro, or nuclear)[38] and captured CO_2. Captured CO_2 could be sourced from fossil fuel combustion (coal or natural gas power plants with carbon capture), biological sources (bioenergy with carbon capture, ethanol production, or gasification), or direct air capture (DAC).

Hydrogen gas produced through the steam reforming of methane (grey hydrogen), steam reforming with carbon capture (blue hydrogen), or electrolysis of water powered by renewable electricity (green

[33] Middlebury College Newsroom. 2017. Anaerobic Digester Fact Sheet. http://www.middlebury.edu/newsroom/archive/2017-news/biodigester-fact-sheet. Accessed March 22, 2022.
[34] VGS. Blended RNG Adder Calculator. https://vgsvt.com/climate/renewable-natural-gas/calculator-blended/. Accessed March 28, 2022.
[35] U.S. EIA. 2022. Natural Gas Prices. https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_a.htm. Accessed March 29, 2022.
[36] Syngas or synthesis gas – not to be confused with synthetic natural gas – is a mixture of carbon monoxide (CO) and hydrogen gas (H_2) that can be chemically reacted under different conditions to produce synthetic natural gas and longer-chain hydrocarbons. It is produced by reacting a solid carbon feedstock (e.g., coal or biomass) with steam at high temperatures and pressures.
[37] Electrochemical processes are more emergent and aim to improve the efficiency of fuel production relative to thermochemical and biological processes like anaerobic digestion. Still, these have yet to be used widely at scale.
[38] Currently, the most common source of hydrogen gas is steam reforming of natural gas. Production of synthetic methane from H_2 produced in this way is unnecessarily redundant, incurring both energy and financial losses with no net benefit in GHG emissions.

hydrogen) has also been floated for potential pipeline injection.[39,40] Hydrogen certainly has an important role to play decarbonizing stubborn sectors like industrial process heating. Its role in building heating is less obvious. Studies show that while hydrogen gas can be blended with natural gas up to 20% of the existing pipeline gas supply, greater use would require the replacement of existing infrastructure and end-use appliances.

Propane & LPG

Propane (C_3H_8) is a hydrocarbon gas that is the majority constituent of liquefied petroleum gas (LPG). LPG is usually a mixture of propane and other short hydrocarbon gases (e.g., butane, propylene) with moderate boiling points, which allow for their transport and storage as a liquid under high pressure but is consumed as a gas. Modest adjustments to equipment burners can enable LPG to be used by many natural gas appliances and end-uses (e.g., space and water heating and cooking). LPG is typically more expensive than natural gas and comparable with fuel oil. Propane is widely available at retail and by truck delivery, but due to its expense is more commonly used in rural areas not served by natural gas and for portable applications like barbecue grills.

The LPG market is much smaller than natural gas and longer-chain hydrocarbons. As a result, pathways to produce renewable LPG have received less attention. Several of these pathways produce dimethyl ether (DME, C_2H_6O), a compound with similar properties to propane, but that is not a normal constituent of LPG. There are several potentially low-carbon pathways to produce DME:

1. Gasification of biomass to produce DME using similar approaches to the gasification of biomass to RNG;
2. Derivation of biologically produced methanol to produce DME;
3. DME or LPG gases are byproducts of several pathways that seek to produce longer-chain hydrocarbons (e.g., oils, gasoline, and sustainable aviation fuels).

Some pathways (e.g., #1 above) can synergize site-specific waste streams. For example, agricultural and food production facilities with anaerobic biogas could add a gasifier to produce syngas from dry waste.

Fuel oil

Heating oil, or fuel oil, comprises longer-chain hydrocarbons transported, stored, and used as a liquid. This limits its use to space and water heating. Heating oil is more expensive than natural gas per unit of energy and has a comparable cost to propane. Fuel oil is widely available by truck delivery. Outside the Northeast, propane is generally favored relative to oil in non-gas-served areas due to its versatility. In the Northeast, fuel oil's everyday use in urban and rural communities is an anachronism of the age of the region's building stock and its historical reliance on oil – established before the growth of natural gas pipelines and LPG infrastructure.

Renewable fuels have a relatively long history and have been subject to intensive research, investment, and policy incentives (e.g., Low-Carbon or Renewable Fuels Standards). Most of this focus has been on liquid transportation fuels. Still, just as there are many similarities among liquid fossil fuels, there are similarities between liquid transportation fuels and heating fuels. For example, biodiesel oil can be produced from several plant or animal byproducts and used in transportation and

[39] Brian Hammerstrom, et al. January 2022. The viability of implementing hydrogen in Massachusetts. Rist Institute for Sustainability and Energy. https://futureofhydrogen.org/wp-content/uploads/2022/02/The-Viability-of-Implementing-Hydrogen-in-Massachusetts.pdf. Accessed March 21, 2022.

[40] Agora Energiewende & Agora Industry. 2021. 12 Insights on Hydrogen. https://www.agora-energiewende.de/en/publications/12-insights-on-hydrogen-publication/. Accessed March 20, 2022.

heating applications. Biodiesel can typically be blended with fuel oil up to 20% in heating applications. Higher levels of blending may require equipment alteration, particularly in older systems.

Synthetic heating oils, including those compatible with existing end-use equipment, can be produced using thermochemical and power-to-liquids processes, similar to those used to make SNG. However, most efforts to commercialize these pathways are focused on producing higher-value products such as jet fuel or kerosene.

Biomass

In the context of building heating, biomass generally refers to firewood or wood pellets combusted for heat. It remains a primary or secondary heat source for a modest number of predominantly rural and suburban homes in the Northeast. Although wood combustion for heat releases biogenic carbon dioxide, unsustainable wood consumption can increase the net loss of carbon from biological systems. There has been some interest in pelletizing agricultural waste for use in heating applications. However, due to the higher ash content of agricultural wastes vis-à-vis wood, it is likely not a drop-in replacement for wood pellets in typical residential heating systems. Commercial-scale heating systems could rely on a more diverse feedstock. Both woody and agricultural wastes used for pellets could also be gasified into RNG or renewable LPG but at higher energetic and financial costs.

Tactical Thermal Transition Study Working Paper: Assessment of Proposed Hybrid Heating Strategies

Michael Jay Walsh, Ph.D.[1]

Working Paper Draft: May 6, 2022

Highlights

- Hybrid heating arrangements integrate a heat pump with existing or updated combustion-based heating systems that utilize pipeline gas or delivered fuels.
- In these situations, the combustion heating system serves as a backup when: (1) the heat pump's rated capacity is insufficient to provide needed heat; and (2) the efficiency of the heat pump declines, which leads to significant increases in electricity demand to meet building heating needs.
- Implementation of hybrid heating strategies seeks to lessen several transition challenges, including high upfront and ongoing operational costs associated with building electrification and the potential impact of sector-wide electrification on electricity supply and distribution resources.
- Non-pipeline fuels can achieve the goals of hybridization, allowing cost-saving pruning of the pipeline distribution system. Such strategies were not evaluated in the 20-80 independent consultant study.
- Hybrid-electrification strategies will likely rely on some use of constrained bioenergy resources to meet emissions targets.
- Non-pipeline fuels offer similar (and possibly greater) advantages to pipeline gas in supporting energy system reliability.
- Gas-hybrid arrangements will have an unstable customer base and require coercive regulation to maintain the financial viability of the gas distribution system and avoid an uncontrolled exit.

Guidance for Decision Makers

- Policy should facilitate the rapid adoption of heat pumps over the next decade in all possible arrangements and contexts.
- Hybrid arrangements (e.g., propane conversion plus heat pumps) can be used to immediately facilitate customer exits from the gas system where aging leak-prone infrastructure is set to be replaced. Such interventions will likely have lower costs than pipeline replacement.

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TABLE 1. SUMMARY OF HYBRID HEATING APPROACHES

	Hybrid Fuel	***Current System***	***Approach***	***Advantages***	***Disadvantages***
Pipeline Gas Hybridization	Gas	Gas	Integrate heat pumps with the existing heating system.	Reduces fuel use and operational costs. Low level of effort.	Maintains current gas system with associated cost and emissions impacts.
Non-Pipeline Hybridization	Oil	Oil	Integrate heat pumps with the existing heating system.	Reduces fuel use and operational costs.	None.
	Propane / Liquefied Petroleum Gas (LPG)	Natural Gas, LPG	Integrate heat pumps with the existing gas system. Retrofit existing gas appliances to use LPG or replace oil heating system.	Disconnects from the gas system while still enabling the use of combustible fuels to meet customer needs and preferences.	Modestly more expensive than Pipeline Gas Hybridization. Requires conversion of existing gas appliances. Propane tank requires outdoor space, which may be difficult in dense locations.
	Biomass Pellets	Oil, Gas, LPG	Replace the existing system with a hybrid pellet-heat pump arrangement.	Eliminates on-site fossil emissions. More optimal use of bioenergy resources for building heat than gaseous or liquid renewable fuels.	Modestly more expensive than Pipeline Gas Hybridization. Potential outdoor air quality impacts. Exclusive reliance on bioenergy resources. Requires pellet storage.
Whole Building Electrification	Electricity	Electric Resistance, Oil, Pipeline Gas, LPG	Replace the entire heating system with heat pumps.	Eliminates on-site fuel needs and emissions.	High upfront and operational costs. Significantly increases electricity demands, higher level of implementation-scale effort.

Background and Context

Hybrid heating arrangements integrate a heat pump with existing or updated combustion-based heating systems that currently exclusively use pipeline gas or delivered fuels (heating oil, propane, pellets). A summary of such arrangements is listed in Table 1. For residential settings, this typically would include installing a ductless mini-split or replacing a central air conditioner system with a central heat pump while maintaining the existing fuel-based system.

In these situations, the combustion heating system serves as a backup when: (1) the heat pump's rated capacity is insufficient to provide needed heat; and (2) the efficiency of the heat pump declines, which leads to significant increases in electricity demand to meet building heating needs. Such cold snaps could sometimes coincide with drops in renewable electricity availability. The operation of each system would be either manually or automatically controlled by an occupant or an intelligent thermostat, respectively. Hybridization also implies that other appliances (hot water, clothes dryers, cooking) may or may not be converted due to customer preferences or allow for replacing such appliances at the end of life.

Hybrid heating arrangements have been quite common for some time and are increasing in prevalence, regionally and nationally. Even 20-years ago, it was not uncommon to see propane and heat pump combinations in the Northeast. Hybrid electrification as an interim or long-term decarbonization strategy aims to scale up such arrangements to reduce emissions while balancing energy system impacts.

Specifically, hybrid electrification seeks to address several challenges associated with the electrification of heat by:

1. Reducing the level, number, and aggregate cost of comprehensive building energy system retrofits such as comprehensive shell retrofits, HVAC system overhauls, and early retirement of gas heating systems and appliances.
2. Reducing the needed sizing of heat pumps and associated costs.
3. Avoiding costly resistance heating in situations where there is insufficient space (e.g., tall buildings with limited roof space) or other practical barriers to heat pump integration.
4. Maintaining a second energy resource that can, *with additional investment,* enhance heating and electric reliability.
5. Avoiding higher electric heating loads and associated user and system costs that emerge when heat pump performance declines while building heat demand increases.
6. Retaining an energy source that provides a specific value to customers (e.g., combustion-based cooking)
7. Avoiding the early retirement of auxiliary equipment (e.g., cooking, water heaters, or clothes dryers,)

Hybridization ultimately requires some use of combustible fuels. Maximizing electric heating can minimize the need to extract, produce, and transport fossil and renewable fuels reducing related costs, emissions, and bioenergy tradeoffs.

As part of the Massachusetts Department of Public Utilities Docket #20-80, the consultant (E3) for the Local Distribution Companies (LDCs) analyzed several scenarios[2] illustrating possible pathways for the evolution of pipeline gas delivery in Massachusetts. The "Hybrid Electrification Scenario" emerged from that analysis as having – through 2050 – the lowest range of costs and implementation complexity. The report further noted "that pathways that coordinate utilization of the gas and electric systems, such as the Hybrid Electrification scenario, show lower overall levels of challenge" and that "the Hybrid Electrification pathway has the lowest cumulative incremental costs" of all the analyzed scenarios.[3]

Stakeholders need to recognize that this scenario simulated the hybridization of *both gas and oil heat.* Subsequently, a significant portion – possibly up to a third[4] – of the electric sector cost savings observed in the Hybrid Electrification Scenario is attributable to the fact that oil heat was hybridized in this scenario and not in other scenarios. This gas-agnostic assumption serves as a thumb on the scale in the utility's interpretations of this scenario.

Concerning the gas distribution system, implementation of gas-hybrid arrangements initially offers a comfortable path to reducing emissions – both through lower upfront investment and lower operating costs relative to other scenarios. However, consumer choices and technological progress have the potential to eventually turn the gas-hybrid path into a knife-edge that would require stringent customer-constraining regulations to maintain.

Intentional or unintentional heat system hybridization will likely be an essential near-term strategy, but as this paper illustrates, it is not necessarily reliant on the pipeline distribution system. **The challenges noted above are addressable with current cost-effective technology and without a pipeline gas network at current size and service levels.**[5] By addressing these challenges with non-pipeline solutions, leak-prone and underused parts of the gas system can be targeted for cost-saving tactical retirement.

[2] E3. The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report, Technical Analysis of Decarbonization Pathways. March 18, 2022. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633269

[3] LDC Common Regulatory Framework. March 18, 2022. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633273

[4] Currently, the relative shares of oil (inclusive of LPG) and gas consumption in the residential, commercial, and industrial sectors are 30% and 70% respectively (2019 SEDS). Oil-heated and gas-heated homes respectively comprise 28% and 52% of the housing stock (2019 US. Census Bureau)

[5] This review acknowledges that there may be a role for a smaller, scaled-back system to meet industrial, resiliency, or reliability needs in certain contexts. A modest amount of fossil fuel use is consistent with net zero emissions energy systems.

Non-pipeline fuels and emerging technology options can achieve the goals of hybridization, allowing scaling back of the pipeline distribution system.

The E3 analysis and the utility proposals do not consider or assess competitive risks from alternative non-pipeline hybrid-heating approaches: LPG, Biomass pellets, and thermal storage. These technologies solve many of the consumer and energy system challenges listed above without the need for a gas distribution network. Their feasibility and ability to generate auxiliary heat at a lower cost will erode the market share of and demand for pipeline-delivered gas under the LDCs' hybrid scenario.

Propane, liquified petroleum gas (LPG), and renewable analogs such as dimethyl ether (DME) are largely substitutable for natural gas in existing appliances with modest modifications, allowing for not only hybridization of heat but also continued use of gas stoves, grills, and fireplaces. LPG availability is currently a fraction of natural gas or heating oil availability and is generally more expensive than pipeline-delivered fossil gas. According to census data, approximately 3% of Massachusetts homes rely on LPG. Hybridizing these homes will open up the fossil propane supply.

Dimethyl ether is largely substitutable for propane and can be produced via methanol synthesis from a methane feedstock or via the gasification of biomass. This allows for the production of both fossil and renewable LPG. Similar LPG-compatible compounds are also a byproduct of sustainable aviation fuel pathways. While such fuels are likely to be more expensive than geologically extracted propane, they will have a similar cost of production to RNG.

A gas to LPG conversion will likely cost a single-family household under $2000. LPG tank rentals, fuel delivery, and decarbonization costs (renewable LPG or compliance credit) are likely to cost less than low-throughput pipeline delivery of RNG – as modeled in the Hybrid Electrification Scenario.

Pellet stoves: some customers may be able to hybridize by installing a pellet stove in a basement or an aesthetically pleasing location. Pellet stoves can be integrated with building heating controls to be run when auxiliary heat is required. While modern pellet stoves have significantly reduced emissions of criteria pollutants, the impact on air quality, even though only used sparingly, should be considered in deployments, possibly limiting the use in urban settings. Wood pellet stove installations are likely to cost under $2000 and have significantly lower delivered-fuel costs than pipeline-delivered RNG or SNG. Pellet fuels use the same biomass feedstocks being identified for RNG production via gasification. In terms of fuel production, pellet fuels are more cost-effective and energy-efficient pathway than gasification.

Such alternatives provide customers who prefer a backup heating system with a cost-effective exit pathway from the gas system. The typical home would require a 125-gal LPG fuel tank to be refilled every other year. Small multifamily homes could share a tank that requires a single annual refill. Pellet consumption would also be modest if operated with a heat pump, requiring low maintenance and deliveries.

This approach was applied to oil-heating and gas-heating systems in the Hybrid Electrification scenario, but oil-system hybridization was not included in other scenarios. In E3's analysis, oil hybridization, like gas, will lower demand-side and electric system costs relative to the complete electrification of oil-heated buildings. As such, a policy decision that is largely agnostic to the disposition of the gas system is responsible for a significant portion of the cost savings in the Hybrid scenario. This inflates the Hybrid Electrification scenario's estimated cost savings relative to the more deeply electrified scenarios.

While not distinctly fuel-heat pump hybrid approaches, other emerging options can also achieve similar aims while allowing customers to exit the gas system. These include *geothermal, thermal storage, or networked systems that integrate various technologies.* These all have the potential to erode gas demand and gas system reliance depending on future costs and perceived value.

Customers' willingness to disconnect from the gas grid and adopt a non-pipeline hybrid approach is unclear. The benefits may not be significant enough to take the extra steps. However, the availability of these options increases optionality for the customer, the utility, and society in a way that needs to be considered more broadly. If such approaches have the potential to lower overall systems costs, incentives can be used to shift customers to these approaches.

The hybrid-LPG approach offers a valuable tool for system planning that makes pipeline closure easier. The cost of hybrid-LPG conversions will likely be somewhat favorable relative to pipeline replacement. Customers in a gas service territory with a higher degree of leak-prone infrastructure or pipelines could be rapidly hybridized, allowing for closure rather than replacing that pipeline. Incentives could be designed to promote such transitions in areas with a higher degree of leak-prone infrastructure, particularly on radial parts of the system that are more amenable to closure.

Hybridization could be a transitional step to higher performing heat pumps[6], integration of thermal or battery storage solutions, more time to expand and strengthen electric distribution infrastructure, staged building envelope improvements, segment scale transitions off of a pipeline, and segment-scale transition to networked geothermal systems.

The possibility of such arrangements could readily facilitate customer exits from the gas system, leading to declining throughput and challenging the financial viability of the gas distribution system.

[6] For the last several years, there has been an assumption that prioritizing the full electrification of oil and LPG-heated homes before gas was preferable from a cost and emissions strategy. Based on the E3 consultant's findings regarding grid reliability and retrofit cost, this understanding may be unfounded. Hybridizing current oil-and LPG heated homes will leave a distributed energy asset in place. This may reduce stress on electric distribution and supply systems.

Hybrid electrification will rely on some use of constrained bioenergy resources. Non-pipeline renewable fuels offer several advantages over RNG.

The gas-hybrid scenario demands significant bioenergy resources that could be more optimally used for sequestration or harder to electrify sectors. It is not clear that RNG will be available at the scales needed to maintain the gas-hybrid scenario. Renewable LPG and pellets are likely to have lower costs, negligible fugitive emissions, higher energy and material use efficiency, implementation flexibility, and lower ecosystem and resource impacts.

Renewable and alternative fuels are essential for net-zero emissions energy systems. However, efforts to utilize them must consider overall constraints on their supply and tradeoffs in their use in specific sectors relative to others. Renewable fuels are best suited for the hardest to electrify sectors such as aviation, industrial heat needs, shipping, and heavy-duty trucking. A separate assessment evaluates these tradeoffs in detail, but key elements are briefly summarized here.

Bioenergy feedstocks have multiple potential biomass-to-energy pathways and potential energy products. Each of these has tradeoffs in cost, energy, and decarbonization potential. The CO_2 abatement cost of heat using pipeline-injected RNG is typically higher than other renewable fuel (and electrification) strategies. These points can be illustrated with several examples:

1. Using biogas at its source to produce renewable heat and electricity avoids the costs and energy losses of purifying the biogas to pipeline quality RNG and pipeline connection. Site use and generation of electricity currently displace site use of fossil fuels and gas consumed to generate electricity for the grid. On-site use can also be designed to integrate biogas storage to increase firm electricity capacity.[7]
2. Biomass and dry organic wastes can be pelletized and used in distributed biomass heating at higher energy efficiencies and lower costs than pipeline injection and consumption of residue-to-RNG pathways.
3. Biomass and organic wastes can generate renewable non-pipeline fuels such as LPG (propane) analogs at similar efficiencies and costs to RNG.
4. Biomass and organic wastes can be used to produce other fuels for harder-to-decarbonize sectors.

[7] Several recent studies, including the LDC Independent Consultant Report and the Massachuestts 2050 Decarbonization Roadmap, have emphasized the need for maintaining or increasing firm electricity capacity such as combined cycle gas turbines or hydrogen turbines, to meet increasing electricity demand and provide system reliability. Biogas production coupled with storage can serve as a modestly sized firm resource for the region.

5. Biomass and organic wastes can be used for carbon dioxide removal (sequestration). It is conceivable that the cost of carbon sequestration could be lower than the carbon premium of RNG.[8]

The last option raises an important regulatory question associated with decarbonizing fuels and heat: If carbon sequestration credits were cheaper and offered more certainty in carbon reduction than the renewable premium of RNG, could the LDC use a sequestration credit to achieve compliance? What about gas pipeline transportation customers who independently procure their gas? What type of sequestration (e.g., biological or geologic) would qualify? It will also be essential to consider aspects related to the quality of a sequestration credit (e.g., permanence) and the quality of the RNG (methane leakage and other life cycle aspects) as the regulatory policy is being designed.

While the E3 analysis assesses the potential costs of RNG bioenergy, it does not provide a clear pathway or plan for sourcing RNG that illustrates likely – rather than general – sources, possible projects, and risks to supply. Presumably, this will be investigated via future utility proposals[9]. However, a more comprehensive assessment of specific sources should be undertaken.

Given the high cost of RNG relative to fossil gas and the need to utilize long-term (10-20 year) contracts in its procurement, locking in RNG also creates potential financial risks, given that a significant number of consumers have the potential to exit the gas system (see below).

Finally, while RNG combustion results in no net change in atmospheric CO_2 emissions, the production of RNG and use in leak-prone infrastructure will still result in significant anthropogenic methane emissions.

It is important to note that the same bioenergy tradeoffs and risks that will affect RNG will also affect other renewable fuels such as renewable LPG and pellets. These include availability, competing uses, life cycle emissions, delivery cost, product lifetime and storage, and other factors. LPG supply should be evaluated: fossil LPG supplies are linked very closely with natural gas production and thus may be constrained, but LPG substitutes can be derived from methane via methanol synthesis; renewable LPG is likely to be a byproduct of sustainable aviation fuel production. Ultimately in a hybrid context, non-pipeline fuels off specific contextual advantages relative to RNG and should seriously be considered as an alternative in hybrid arrangements.

[8] See Charm Industrial for an example of this technology. Current sequestration costs are $600 per tonne CO2. Charm has established a target of $45 per ton, however this value may be ambitious. Abatement costs below $300 per ton will significantly challenge the abatement value of RNG. https://charmindustrial.com/.

[9] Liberty Utilities has filed a proposal with the DPU to produce RNG from landfill gas currently being used to generate renewable electricity. https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber/22-32

Reliability & Resiliency

Distributed-hybrid approaches provide a similar, or potentially more, energy system reliability and resiliency relative to that of the gas-hybrid approach. Any minor tradeoffs emerge from distributed energy stores (LPG tank, pellet hopper) versus a central delivery system (the gas pipelines).

The infrastructure reliability and resiliency needs of net zero emissions energy systems require a better understanding than is currently available today. The E3 report emphasizes this fact, stating that: "current standards have not been designed or rigorously evaluated in the context of an electric grid that serves the majority of transportation and space heating needs, in addition to other electric loads." The E3 report further contextualizes its analysis as limited, "the Consultants do not attempt to rank or categorize resilience across the decarbonization pathways evaluated in this Report." The reader is encouraged to review E3's nuanced description of these topics in the Consultant Report.[10]

National Grid's Enablement Plan goes beyond the nuance and claims that its plan is "more likely to provide higher energy system reliability and resilience by utilizing both the gas and electricity systems" and "supports overall energy system resilience both by virtue of maintaining two energy systems and through the underground and seasonal storage capabilities of the gas network."[11]

Building Level Reliability & Resiliency

The enablement plans fail to acknowledge that having a second energy distribution system does not necessarily guarantee reliability and does not cover what additional measures would be needed for the gas system to improve its reliability. Most gas-heated homes require electricity to distribute heat since modern heating systems do not work without electricity. Additional interventions – not analyzed by E3 or discussed in the enablement plans – would be required to utilize the gas system as a reliability asset. For example, a home would need a gasoline or diesel electricity generator, an expensive battery, or an expensive pipeline gas-connected generator to achieve a higher degree of building resiliency.

The National Grid Enablement Plan also fails to note that comprehensive building shell retrofits – excluded from the modeled Hybrid Electrification Scenario – are an important reliability and resiliency intervention. Better insulated, weatherized homes keep their heat longer, reducing the need for backup heating or costly reliability measures. The other modeled scenarios with more extensive energy retrofits exhibit higher building-level resiliency than the Hybrid Electrification scenario.

[10] Page 87 of E3. The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report, Technical Analysis of Decarbonization Pathways. March 18, 2022. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633269

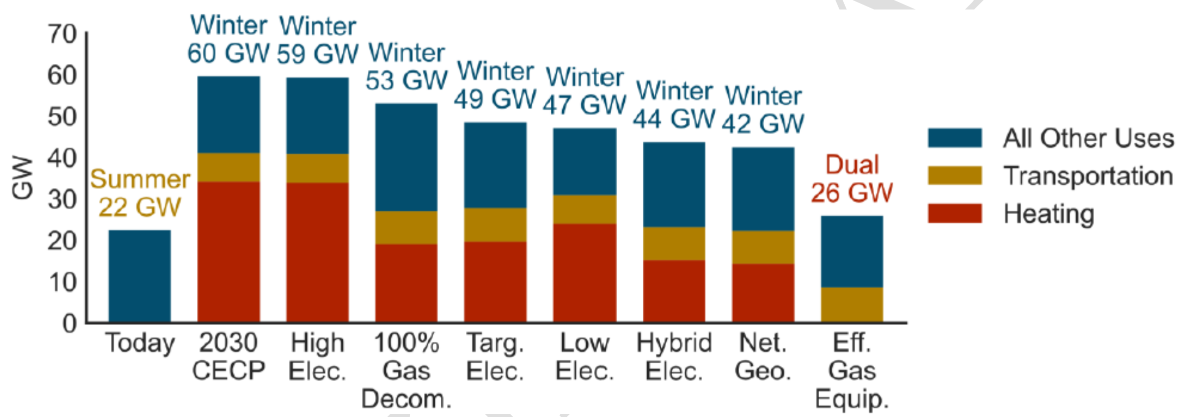
[11] Pages 18 & 19 of LDC Common Regulatory Framework. March 18, 2022. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14633273

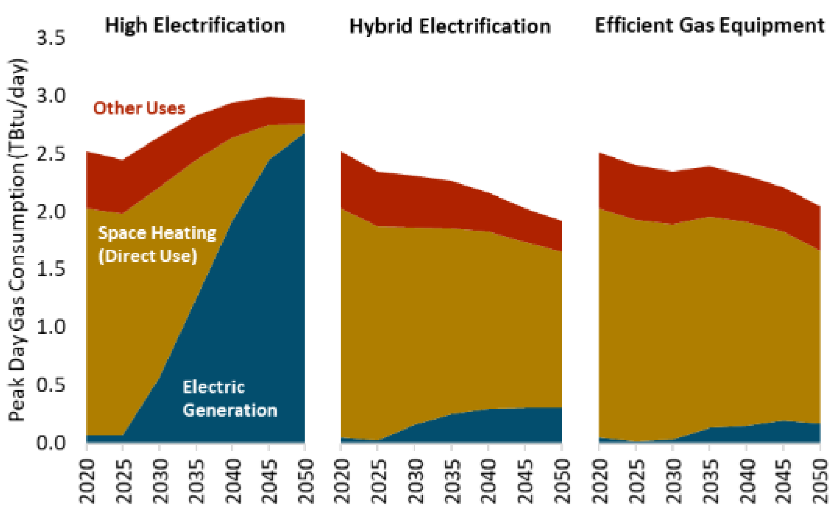
Deployment of integrated solutions like networked geothermal will also increase opportunities for resiliency. Integration of backup heating in networked geothermal systems would support the resiliency of those systems while also being able to co-generate electricity that could be delivered to critical components of that service area via a microgrid.

The reliability of electrical systems can be improved by undergrounding wires to reduce exposure to extreme weather events that could cause downed lines or damaged equipment. While likely costly on its own, electrical undergrounding could be cost-effectively paired with segment-level comprehensive upgrades that combine undergrounding, geothermal network construction, gas line decommissioning, and other street upgrades.

Grid Level Reliability & Resiliency

Hybrid heating approaches reduce the potential peak electricity and total gas system (electric + heating) associated with deep building electrification as illustrated in Figures 20 and 25 of the Independent Consultant Report shown below. The same outcome can be achieved using non-pipeline hybridization.





The Role of Customer Choice

The E3 report and the enablement plans do not sufficiently consider possible shifts in consumer behavior and technological shifts that would significantly put the purpose of the gas-hybrid scenario at risk. The Enablement Plan also claims that it "Preserves Customer Choice for Heating and Cooking." This claim is unfounded as customers could still be allowed to cook and heat with propane.

Customers currently have limited choices when it comes to their heating system. 2019 Census data indicate that 38% of Massachusetts households are renters and effectively have no choice in heating energy. Owners who have agency over their heating system and appliances are often forced by circumstance into like-for-like replacement and are unable to evaluate more suitable or economic options fully. Homes that include heat pumps command a higher resale value than those that do not,[12] highlighting the trend that consumers will increasingly adopt newer technologies that provide additional economic and perceived value.

Customers who exit the gas system, either by choice, economics, or segment closure, will still be able to cook with LPG fuels at a modest conversion expense if they desire open-flame cooking. An exit of the gas system will prompt many customers to consider the health, cost, and experience value of open-flame cooking. Still, customers will be able to keep appliances such as fireplaces, grills, and laundry dryers if they choose to by switching to LPG. The carbon premium (renewable LPG, offset, compliance mechanism) of delivered and consumed LPG may be less than pipeline-delivered RNG or fossil gas, and the continued cost of a gas connection for these low-volume uses, particularly in future low-throughput systems.

Distributed LPG hybridization allows customers to keep existing gas-based heating systems throughout their lifetime. This avoids burdening customers with early retirement, allowing them to undergo a flexible and planned transition for their energy consumption needs, particularly if their gas segment was retired while their heating equipment was still operational.

Consumers will increasingly favor electric technologies because they will be more capable of providing economic or experience value than existing appliances. Gas cooking has historically been publicized as offering the best cooking experience. Induction cooking is challenging that perception and is objectively better than gas at boiling water. The user experience of electric resistance cooking has also improved due to better design and more efficient elements. Concerns regarding the impact of stove-related methane leaks and combustion by-products are also gaining significant attention leading customers to switch. Induction cooktops can be purchased for less than $100, and induction's modular or countertop-integrated design options can create a more flexible kitchen space. Current market trends indicate that electric cooking will measurably disrupt gas cooking in the coming years. Hybrid heat pump water heaters are also likely to achieve cost savings

[12] https://www.nature.com/articles/s41560-020-00706-4

relative to gas via flexible timing, possibly with little impact on hot water preferences. Electric LED fireplaces offer a greater range of lighting choices and styles.

Risks Associated with Customer Exit

The assumption that pipeline-delivered gas will continue to be consumers' preferred energy source – in a way that maintains support for the gas system – is unfounded. The E3 report and utility plans fail to anticipate declining gas demand and its consequences for the stability of a hybrid-gas system. Consumer's ability to exit the pipeline gas system – driven by a growing preference for electric technologies and enabled by emerging all-electric or non-pipeline hybrid heating pathways – creates significant risks for maintaining the economic viability of the pipeline distribution systems.

If large-scale consumer exit proceeds, both the costs of maintaining the pipeline gas system and the costs associated with expensive long-term renewable fuels supply contracts will be concentrated over a declining user base and would likely require an assumption of the risk and debts of the system by society at large.

The hybrid scenario needs to maintain a sufficiently high customer count and throughput to keep rates low enough to avoid significant customer exit. However, the risk of customer exit and an implied desire to regulate the hybrid scenario to balance energy resources may necessitate burdensome gas system exit fees on consumers – the national grid enablement plan acknowledges this potential dynamic. Further, suppose full whole-home electrification became advantageous at the household level. A lack of sufficient electric resource planning could become a practical and economic barrier to customer choice to electrify.

Workforce & Economic Impacts

Because the hybrid scenario does not fully address risks associated with an uncontrolled customer exit (though improved technology or the adoption of distributed fuel heating), it places its workforce at significant risk of being substantially impacted by an uncontrolled transition. A managed transition off pipeline gas in targeted areas can facilitate a just workforce transition more readily. Notably, deploying networked heating solutions that integrate ground-source heat pumps leverages existing workforce capacities and skillsets.

Heat pumps produce heat from the local ambient air using local capital investment. Alternatively, fossil and renewable fuels will need to be imported leading to spending money out of state. While some electrification strategies may be more expensive, they may have more favorable economic outcomes because such strategies keep spending local.

Conclusion

Rising to climate change's mitigation challenge requires an ambitious effort to reshape the energy system. Balancing that ambition with practicality in an evolving technological landscape is challenging for the public, policymakers, and even energy systems experts and practitioners. Prior work (including those that the author was involved in) mapped out the needed ambition while acknowledging some of the scaling challenges associated with that ambition (e.g., large-scale building electrification).

The E3 report represents an informative next step in understanding pathways for how best to decarbonize the regional energy system in alignment with Massachusetts' Net Zero Goal. The E3 hybridization analysis presents a case for a more granular or segmented approach to building decarbonization, where prior work encouraged comprehensive retrofits at crucial intervention points. Both approaches have their role, but as discussed above, having a steppingstone opens up new possibilities and accelerates the potential for a planned transition from the gas system and deployment of networked energy systems.

While the analysis is an important step forward, the study, by not considering a non-pipeline hybrid approach, is not comprehensive enough to support the plans offered by the LDCs.

The LDC's study work originated with a flawed thesis on customer preferences and technological change that appropriately recognized barriers but failed to anticipate how technological change can disrupt existing business models. The lack of consideration of the possibility of non-pipeline hybrid technologies demonstrates the limits of the study's conclusions. More concerning is that the study's overall design fails to recognize that there is a distinct possibility that customers may, in mass, choose to exit the gas system as a result of cost or value preferences.

While exploring scenarios that continue to maintain the pipeline gas system is an essential component of this investigation, the lack of scenarios that evaluated strategies for decommissioning significant portions of the gas system leaves a significant information gap.

Tactical Thermal Transition Study Working Paper: Estimated Electrification-Driven Utility Changes in Customers and Sales in Massachusetts

Michael Jay Walsh, Ph.D.[1]

Working Paper Draft: May 6, 2022

Highlights

- Massachusetts contains many towns (155 of 216) and customers (1 million of 1.7 million gas services) served by separate gas and electric providers. This is predominantly driven by the incongruent gas and electric territories of the state's two largest gas and electric investor-owned utilities (Eversource and National Grid). Additionally, a smaller but not insignificant number of communities and customers are served by municipal electric utilities in these IOU gas territories.
- Electrification will result in a significant transfer of thermal energy sales from National Grid to Eversource and the municipal electric utilities. This transfer will play out across communities in Massachusetts, but on the net is approximately the size of the transfer of National Grid's Boston gas customers to Eversource.
- Electrification of oil heat will allow the major IOUs to increase their electric thermal sales base.
- The significant number of customer and sales transfers between utilities, particularly in the Commonwealth's most energy-demanding communities (e.g., Boston and Worcester), presents a planning challenge for electrification and decarbonization.

Guidance for Decision Makers

- Regulators will need to develop a framework for cross-utility planning to support customer transitions and minimize costs.
- Such efforts should prioritize planning for areas with large loads, older gas and electric infrastructure, and historically marginalized communities.

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Findings

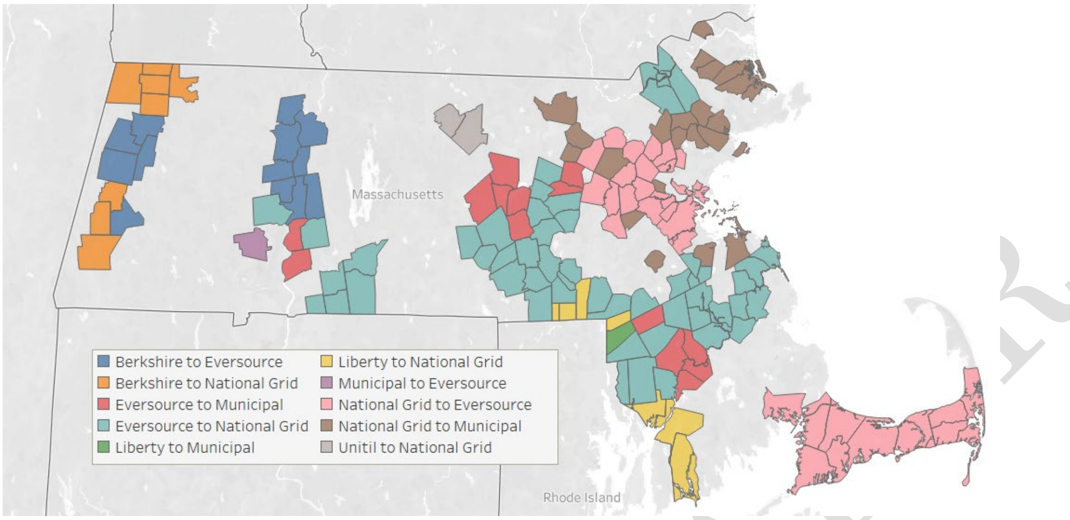

Figure 1. Gas to electric utility service area transitions. The figure excludes towns where the gas to electric energy demand shifts to the same parent investor-owned or municipal utility and towns without gas service.

Electrification of heating is anticipated to significantly increase electricity demands and reduce oil and gas consumption as Massachusetts pursues its net zero emissions target. This will concomitantly reduce gas utility customers and sales while increasing sales by electric utilities. This transition will have considerable implications for utility planning.

Currently, 155 of 216 gas-served municipalities host customers that receive electricity and gas service from a differently owned provider (Figure 1). These communities contain nearly 1 million customers representing approximately 57% of the gas customer base and 53% of the utilities' gas sales.

Given this arrangement, electrification of gas end uses (e.g., heat, hot water, cooking) could shift a significant number of customers and thermal energy demand[2] from one utility to another. This could generate several potential challenges to decarbonization. For example, utilities may develop conflicting customer decarbonization strategies. Further, decarbonization planning by the utility, customers, and municipalities is easier in single-utility franchise areas than in areas with separate gas and electric providers.

A recent report[3] by the Regulatory Assistance Project (RAP) recommended that regulators consider coordinating planning processes that may affect gas and electric utility decision making – not only among the utilities that operate in the same

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[2] This analysis uses thermal energy demand to describe the current gas- and oil-equivalent energy consumption in the residential and commercial sectors. Electrification will result in lower levels of fuel or electricity demand, primarily though the adoption of more efficient electric heat pumps.

[3] Anderson, M., LeBel, M., & Dupuy, M. (2021, May). Under pressure: Gas utility regulation for a time of transition. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2021/05/rap-anderson-lebel-dupuy-under-pressure-gas-utility-regulation-time-transition-2021-may.pdf

service area – but also involving other stakeholders such as municipal infrastructure planners, ratepayers, and advocacy organizations.

This analysis finds that the need for cross-utility planning in Massachusetts is likely to be significant in advancing thermal decarbonization goals. Regulatory processes such as the DPU's investigation into the future of gas (docket 20-80) should focus on enabling effective and inclusive planning that coordinates both gas and electric actions among stakeholders.

Figure 2 shows the potential transfers of customers and gas sales from gas local distribution companies to electric distribution companies based on 2019 customer counts and energy sales. The figure also includes the electrification of residential oil. There is a substantial shuffling of customers between National Grid, Eversource, and the municipal utilities that – on the net – results in significant customer and thermal energy sales increases for Eversource and the municipal utilities (Figure 3). National Grid loses many of its gas customers and related sales but essentially balances those losses with gains from the electrification of oil customers.

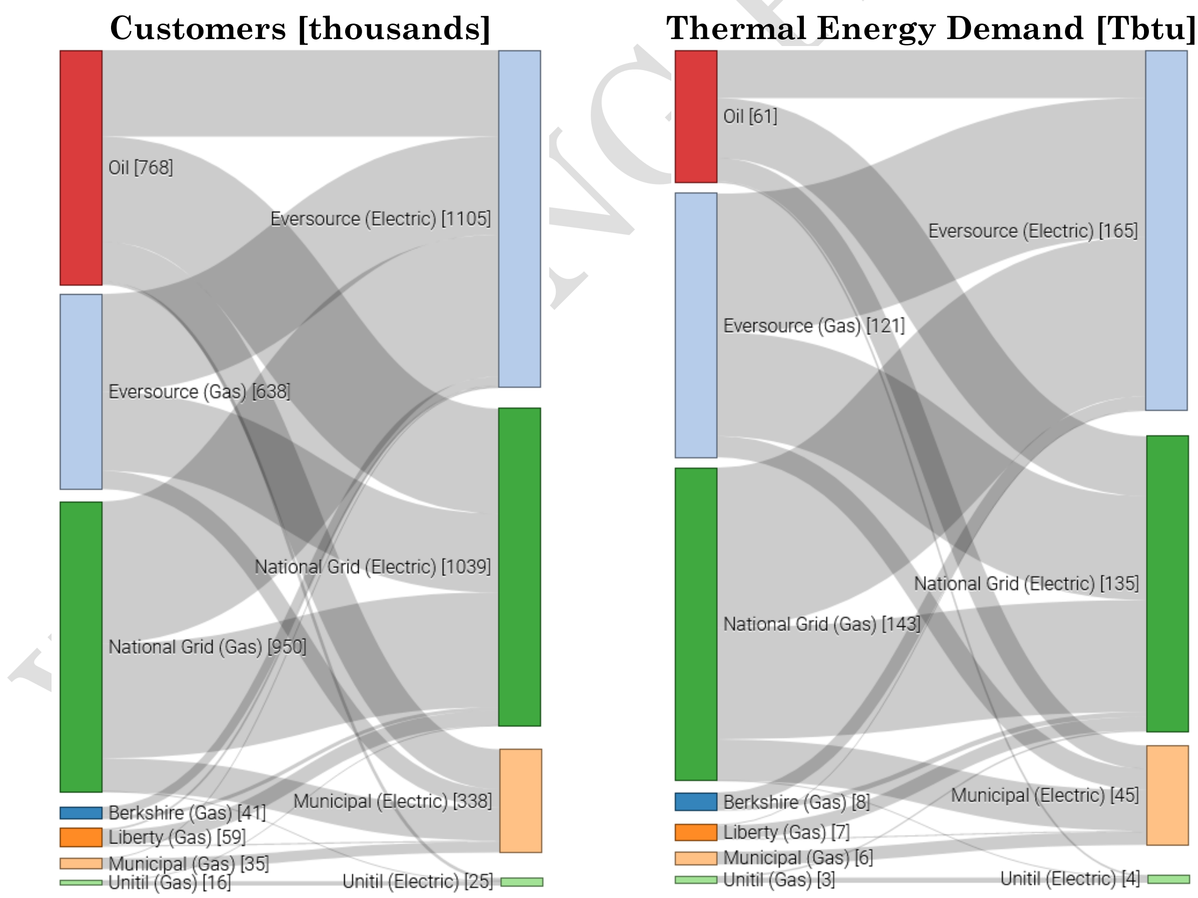

Figure 2. Sankey diagrams of the customer (left) and thermal energy demand (right) under a transition from gas and oil/LPG to electricity. This data is also shown in Table 1 and Table 2 in the appendix. The figure does not include commercial and industrial oil sales, 11 Tbtu in 2019. Commercial fuel oil consumption data is not available at the sub-state level and thus cannot be mapped to utility territory.

Boston contains a significant portion of the energy and customer base at risk of transfer from National Grid to Eversource (Figure 4). This number is approximate to National Grid's total potential losses. In 2019 Boston contained nearly 170 thousand National Grid gas customers who consumed approximately 30 TBtu of gas. The remainder of National Grid's potential transfer includes several metro-Boston and Cape Cod communities. It should also be noted that several other large cities are served by separate gas and electric utilities. Worcester and Lawrence – communities with significant environmental justice populations – transition from Eversource to National Grid. Berkshire Gas (owned by Avangrid) and Liberty Utilities, as gas-only utilities, have no potential to make up lost customers or sales from electrification in the state.

Electric utilities will also gain customers from the electrification of oil-heated homes. Where gas heats approximately half of homes in the Commonwealth, a quarter and 3% of homes are heated by oil and LPG. The distribution of (non-utility) oil and LPG-heated households and energy consumption across utility territories are shown in Table 3 and Table 4, respectively. There is no readily available data on commercial oil or LPG consumption that can be mapped to utility territories.

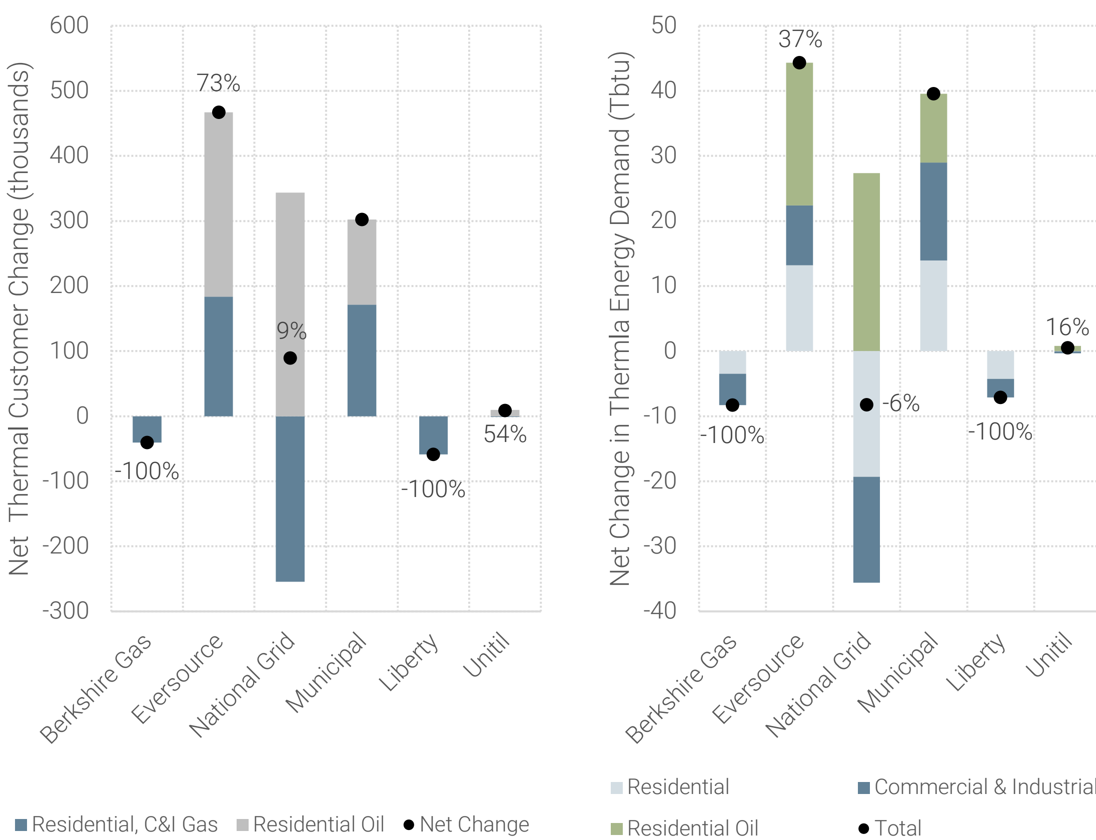

Figure 3. The net change in each utility's customers and thermal energy served resulting from electrification.

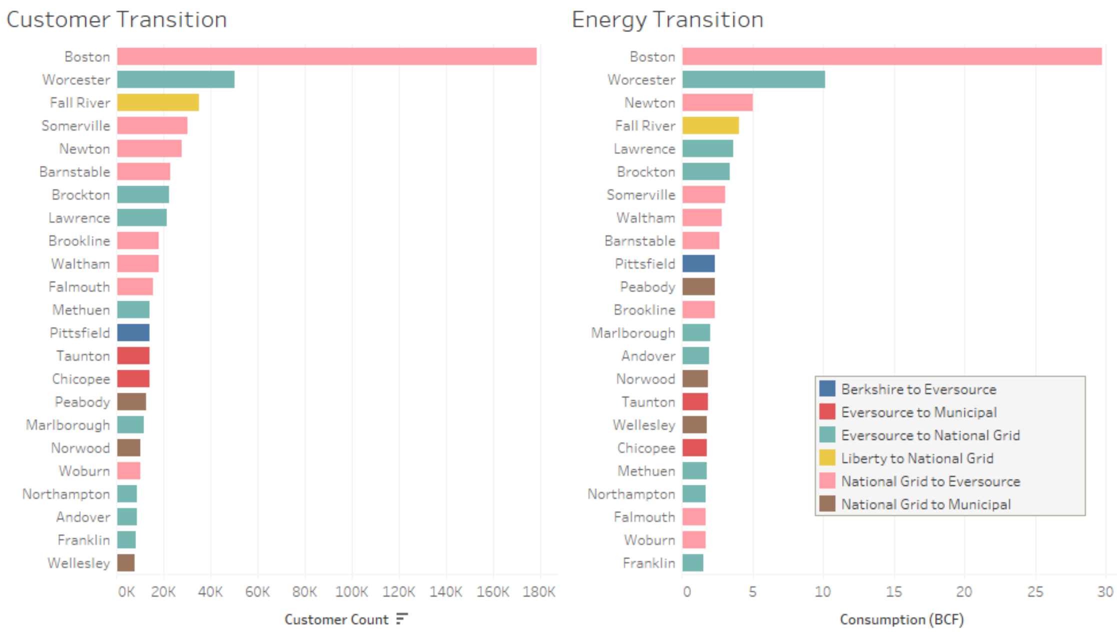

Figure 4. The town's customer and gas consumption for the top-served towns with separate gas and electric providers. Transitions Somerville and Boston have approximately 10,000 customers currently served by National Grid.

Implications

The current incongruent shape of the state's gas and electricity territories is an anachronism of the historical development of gas and electric utilities which largely emerged as small separate entities focused on serving a municipality. Over time, gas entities generally merged with other gas providers, while electric entities merged with other electric providers. Recently, separate gas and electric providers were combined under singular corporate monikers. For example, in the early 2000s, National Grid brought together customers from the former Massachusetts Electric Company with those in the former Boston Gas territory (previously owned by Keyspan).

The sizeable potential shifting of customers presents a significant planning challenge for both gas and electric utilities. Utilities that operate both gas and electric service in a specific territory benefit from having access to customer energy consumption data. This would allow utilities to more accurately project changes to electric demand from heating electrification and provide more insight into potential building-level efficiency opportunities. Having access to this information would allow the utility to make planning and investment decisions more effectively at the local scale.

Electric utilities that stand to gain customers and demand will be faced with the need to plan for the addition of such heat demand but may not have access to the customer's historical thermal energy consumption data. This is particularly important for transitioning commercial heat, which is more complicated and variable across consumers and has the potential to strain current electric distribution systems.

The resulting dynamic has implications for decarbonization planning, as discussed here. There are currently three strategies for decarbonizing gas heating services:

1. The gas utility substitutes fossil methane with methane derived from renewable sources or processes. This would allow gas distribution companies to continue their current business model with negligible customer building-side interventions, but this approach has limited scalability and high costs that would lead to customer exits.
2. Electrification of building heating demands would shift the customer and associated sales from the gas utility to the electric utility. If done at scale, such a transition would require significant cross-utility planning. The high cost of electrification relative to fossil methane is currently a barrier to electrification, but performance improvements and increasing costs of maintaining a decarbonized pipeline gas system may incentivize transitions over the long run.
3. The gas utility shifts to a thermal, rather than gas, distribution model if allowed by a regulator. A thermal distribution model could include networked ground source heat pumps or similar hydronic or steam-based district energy systems. This approach would allow the utility to retain both customers and thermal sales where it is applied. However, given operating power requirements such as the system, coordination with the local electric utility may be necessary.

Electrification (Strategy #2) will likely be the predominant strategy for decarbonizing most of the state's buildings. However, all three strategies may contribute to decarbonization in a given territory. Boston, for example, given its density and the complex thermal demand of a number of the City's buildings, may utilize higher levels of renewable fuel and more widely employ district solutions such as networked geothermal. Since the city is served by different gas (National Grid) and electric providers (Eversource) and given the higher cost and complexity of utility systems in the urban core, there will be a greater need for integrated energy system planning to support customers as they and the city as a whole decarbonize.

Methods

Town-level customer count data was extracted from annual utility returns to the Massachusetts Department of Public Utilities (DPU)[4]. Town-level gas consumption data for the residential and combined commercial-industrial sector was obtained from reported MassSave Program Data[5] for investor-owned utilities and DPU annual return data for municipal gas utilities. Utility service areas were obtained from MassGIS[6] 2019 data and were used to provide a representative recent year that avoided any potential impacts from the COVID 2019 pandemic. American Community Survey 5-year estimates for household heating fuel (Table B25040) at the block group level were used to estimate the prevalence of these homes by utility territory. 2015 EIA Residential Community Survey Data New England average fuel consumption per household was applied to this data to estimate oil and LPG energy demands by a utility area.

[4] MA Department of Public Utilities Annual Returns: https://www.mass.gov/financial-and-operating-annual-returns-to-the-dpu
[5] MassSave Geographic Energy Use Data: https://www.masssavedata.com/Public/GeographicSavings?view=C
[6] MassGIS Data. https://www.mass.gov/info-details/massgis-data-public-utility-service-providers

Data Appendix

*Table 1. Gas utility customers by gas and electric service territory. **Bolded** values indicate customers served by the same energy provider.*

	Customers (thousands)	Electric Utilities				
		Eversource	*Municipal*	*National Grid*	*Unitil*	*Total*
Gas Utilities	*Berkshire*	29		12		41
	Eversource	**321**	59	258		638
	Liberty	6	4	48		59
	Municipal		**34**			34
	National Grid	465	109	**375**	1	950
	Unitil			2	**14**	16
	Total	820	207	696	15	1738

*Table 2. Gas sales (Tbtu) by gas and electric service territories. **Bolded** values indicate sales from the same energy provider.*

	Gas Sales (TBtu)	Electric Utilities				
		Eversource	*Municipal*	*National Grid*	*Unitil*	*Total*
Gas Utilities	*Berkshire*	6.0		2.3		8.3
	Eversource	**63.4**	9.6	47.5		120.5
	Liberty	0.5	0.6	6.1		7.1
	Municipal		**5.9**			5.9
	National Grid	73.0	18.8	**51.1**	0.3	143.2
	Unitil			0.6	**2.4**	3.0
	Total	142.9	34.9	107.7	2.7	288.2

Table 3. Oil and LPG households by gas and electric utility territory. Households are mapped to the utility by the town's predominant utility. Households in towns with gas service may be outside the actual gas service area. Data on the number of commercial oil customers are not available below the state level and cannot be mapped to utility territory. 2019 Commercial and Industrial oil uses comprised approximately 11 TBtu (EIA).

	Residential Oil/LPG Customers (Thousands)	Electric Utilities				
		Eversource	Municipal	National Grid	Unitil	**Total**
Gas Utilities	Berkshire	21		8		29
	Eversource	117	44	134		296
	Liberty	5	5	11		22
	Municipal	1	16			17
	National Grid	118	58	142		318
	Until			7	10	17
	No Natural Gas Service	20	7	42		69
	Total	283	131	344	10	767

Table 4. Oil and LPG consumption by gas and electric utility territory. Households are mapped to the utility by the town's predominant utility. Households in towns with gas service may be outside the actual gas service area. Data on commercial oil energy consumption is unavailable below the state level and cannot be mapped to utility territory.

	Residential Oil/LPG Customers (Thousands)	Electric Utilities				
		Eversource	Municipal	National Grid	Unitil	**Total**
Gas Utilities	Berkshire	1.7	0.0	0.6		2.2
	Eversource	9.2	3.6	10.8		23.6
	Liberty	0.4	0.4	0.9		1.7
	Municipal	0.1	1.3	0.0		1.4
	National Grid	9.2	4.7	11.3		25.3
	Until			0.6	0.8	1.4
	No Natural Gas Service	1.3	0.6	3.2		5.1
	Total	21.9	10.6	27.3	0.8	60.6