Massachusetts D.P.U. 20-80

February 15, 2022

The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals

Independent Consultant Report – DRAFT

Part I: Technical Analysis of Decarbonization Pathways

Energy+Environmental Economics

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Contents

Glossary of Terms

ASHP: Air-Source Heat Pump.

BTU or Btu: British thermal unit. 1 BTU = 1,055 joules.

Biomethane: Methane produced from organic matter, through anaerobic digestion or gasification.

Bundled customers: Customers who receive both energy supply and delivery services from their local natural gas distribution utility.

CAGR: Compound Annual Growth Rate.

ccASHP: Cold-Climate Air-Source Heat Pump.

CCS: Carbon Capture and Storage. A process that captures carbon dioxide before it enters the atmosphere and stores it for long periods of time.

CDD: Cooling Degree Day(s). A measurement designed to quantify the demand for energy needed to cool buildings, based on the number of days and number of degrees where the temperature is above 65 degrees Fahrenheit.

CO_2: Carbon dioxide.

Consultants: E3 and ScottMadden.

COP: Coefficient of Performance. A measure of efficiency for a heating or cooling appliance.

CNG: Compressed Natural Gas.

Decarbonization Pathways: Economywide transformations that result in emissions reductions over time, involving replacing end-use appliances with high efficiency models, electrifying end uses, employing efficiency measures, and decarbonizing fuel and electric supplies. Eight such pathways were developed by the Consultants for Massachusetts, all of which achieve the same economy-wide climate goals, i.e., 90% gross GHG reductions and net-zero GHGs by 2050 compared to 1990 levels,[1] as well as interim statutory emissions reduction goals of 50% by 2030 and 75% by 2040.[2]

ERM: Environmental Resources Management. Consultants contracted by the LDCs to facilitate the stakeholder process.

Dunkelflaute: Multi-day periods with sustained low generation from weather-dependent renewables.

D.P.U. or Department: Massachusetts Department of Public Utilities.

D.P.U. 20-80: Docket Number referring to the investigation by the Department of Public Utilities on the role of local gas distribution companies as the Commonwealth achieves its 2050 climate goals.

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[1] Consistent with the 2050 Roadmap, remaining emissions in 2050 are assumed to be netted off by carbon sinks to achieve carbon neutrality by 2050.

[2] Chapter 8 of the Acts of 2021, "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy"

E3: Energy and Environmental Economics, Inc. Consultants contracted by the LDCs to investigate decarbonization pathways and the role of gas LDCs.

EIA: The U.S. Energy Information Administration.

ELCC: Effective Load Carrying Capability. A metric used in electric system planning to assess the capacity value (reliability contribution) of a resource.

EJ: Environmental Justice.

Embedded gas system costs: The original costs of installed utility plant (physical gas system assets) on the Massachusetts gas distribution system less accumulated depreciation. Embedded gas system costs illustrated in this report refer to the LDCs' aggregate value of rate base.

Energy efficiency: Energy saving measures. In this study, energy efficiency is a foundational component of all decarbonization pathways and include building shell efficiency improvements; electrification; in-kind, high-efficiency replacements; and industrial manufacturing efficiency.

EV: Electric Vehicle.

FERC: Federal Energy Regulatory Commission. An independent agency that regulates the interstate transmission of electricity, natural gas, and oil.

GHG: Greenhouse Gas.

GSEP: Gas System Enhancement Plans. The Gas Leaks Act passed in 2014 permitted gas distribution companies in Massachusetts to submit annual Gas System Enhancement Programs for replacement of aged infrastructure during the following calendar year.[3]

GSHP: Ground-Source Heat Pump.

GSP: Gross State Product. Gross domestic product of a state.

GW: Gigawatt. One gigawatt is equal to one billion (1×10^9) watts.

GWP: Global Warming Potential. Measures the amount of heat a gas absorbs over a given period of time, relative to the heat that would be absorbed by the same mass of carbon dioxide.

HDD: Heating degree day(s). A measurement designed to quantify the demand for energy needed to heat buildings, based on the number of days and number of degrees where the temperature is below 65 degrees Fahrenheit.

Hybrid heat pump: An air-source heat pump that is paired with a gas furnace or fuel oil back-up. The backup can be powered by renewable fuels.

Hybrid electrification: Electrification strategy that combines electric heat pumps with a gas back-up for space heating.

H_2: Hydrogen gas.

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[3] See: https://www.mass.gov/lists/gseps-pursuant-to-2014-gas-leaks-act.

Interim 2030 CECP: *Interim Clean Energy and Climate Plan for 2030* developed by the Massachusetts Executive Office of Energy and Environmental Affairs, released in December 2020.[4]

ISO-NE: The Independent System Operator of New England. An independent organization that oversees the operation of New England's bulk electric power system, administers the region's competitive wholesale electricity markets, and manages the regional power system planning process.

Large energy user: Customers that purchase large volumes of natural gas, including large commercial and industrial customers. These customers are usually "delivery only" customers that utilize an LDCs delivery service but procure natural gas separately.

LDCs: The five Massachusetts gas local distribution companies: The Berkshire Gas Company ("Berkshire"), NSTAR Gas Company and Eversource Gas Company ("Eversource"), Liberty Utilities (New England Natural Gas Company) Corp. ("Liberty"), Boston Gas Company ("National Grid"), and Fitchburg Gas & Electric Light Company ("Unitil").

LNG: Liquefied Natural Gas.

Long-term capacity contracts: A pipeline or storage contract that provides firm capacity rights over a long period of time.

kWh: Kilowatt-hour. 1 kWh = 3.6×10^6 joules.

MassSave: An initiative in Massachusetts designed to provide services, incentives, trainings, and information promoting energy efficiency that help residents and businesses manage energy use and related costs. The initiative is a partnership between the Massachusetts Department of Energy Resources and program sponsors, including Massachusetts' natural gas and electric utilities and energy efficiency providers.

Migrating or non-migrating customers: Gas customers that adopt ("migrating customers") or do not adopt ("non-migrating customers") a decarbonization technology. Migrating customers do not necessarily depart from the gas system under this definition.

Networked geothermal: A shared system of ground-source heat pumps that delivers heating and cooling through a network of pipes.

O&M: Operations and Maintenance.

PRM: Planning Reserve Margin. A metric used in electric system planning to ensure that there are adequate resources to meet forecasted load over time.

Retail choice: Customer choice program that gives customers the option to "unbundle" their natural gas service and purchase natural gas from a natural gas supplier/marketer that is different from the local natural gas utility.

Renewable fuels: Umbrella term referring to renewably produced alternatives to fossil fuels. This includes renewable gases in the distribution system, as well as renewable fuels in the transportation sector.

[4] See: https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030.

Renewable gas: Umbrella term referring to renewably produced alternatives to natural gas that can be blended into the distribution pipeline system. Renewable gases include biomethane produced through anaerobic digestion or gasification, renewable hydrogen and Synthetic Natural Gas (SNG) produced from renewable hydrogen and a climate-neutral source of carbon.

Renewable hydrogen: Hydrogen produced from electrolysis powered by renewable energy.

Roadmap: The Massachusetts 2050 Decarbonization Roadmap study developed by the Executive Office of Energy and Environmental Affairs to explore strategies to reduce emissions and achieve the Commonwealth's climate goals.[5]

ScottMadden: ScottMadden, Inc. Consultants contracted by the LDCs to investigate decarbonization pathways and the role of gas LDCs.

SEP: Stakeholder Engagement Plan developed by the LDCs and stakeholders in the D.P.U. 20-80 process.

SNG: Synthetic Natural Gas. In this study, synthetic natural gas refers to methane that is chemically synthesized from renewable hydrogen and a climate-neutral source of carbon dioxide from biomass or Direct Air Capture.

Therm: Unit of heat energy. 1 therm = 100,000 BTU.

T&D: Transmission and Distribution.

TBTU or TBtu: Trillion BTU.

TRL: Technology Readiness Level.

TWh: Terawatt-hour. 1 TWh = 1×10^9 kWh = 3.6×10^{15} joules.

Utility gas plant: Physical assets owned by LDCs, including mains, meters & services, and storage facilities.

[5] See: https://www.mass.gov/info-details/ma-decarbonization-roadmap.

Executive Summary

About this Report

This report provides an independent assessment of the role of the Massachusetts Local Gas Distribution Companies ("LDCs")[6] in helping the Commonwealth achieve its 2050 climate goals.

Energy and Environmental Economics, Inc. ("E3") and ScottMadden Inc. ("ScottMadden") (collectively "the Consultants") were selected by the LDCs to develop this report in response to the Massachusetts Department of Public Utilities ("the Department" or "D.P.U.") Docket 20-80. The Docket was opened to *"examine the role of Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth to achieve its 2050 climate goals"* and "*explore strategies to enable the Commonwealth to move into its net-zero greenhouse gas ("GHG") emissions energy future, while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth*"[7].

The Consultants developed an economy-wide analysis of eight decarbonization pathways for Massachusetts using analytical methods and data that are similar to the approach applied in the Massachusetts 2050 Roadmap ("the Roadmap"). All eight pathways achieve 90% gross GHG reductions and net zero GHGs by 2050 compared to 1990 levels[8], as well as interim statutory GHG reduction goals of 50% by 2030 and 75% by 2040.[9] The pathways are designed to reflect different futures for the LDCs and their customers, ranging from ongoing use of the LDCs' distribution networks to 100% decommissioning of gas distribution infrastructure in the Commonwealth.

These decarbonization pathways are not forecasts, nor do they result in a single preferred solution. Instead, by examining multiple pathways, this analysis is used to identify and compare key features of different plausible futures and their relative costs, feasibility, and risks.

Key findings

All pathways imply transformational changes for the Commonwealth, the LDCs and their customers. Strategies that use both the gas and electric systems to deliver low-carbon heat to buildings show lower levels of challenge across a range of evaluation criteria.

Figure 1 evaluates the feasibility of different pathways by comparing the level of challenge of different evaluation criteria. All scenarios are designed to achieve the same level of greenhouse gas reductions, safety and electric system reliability. Figure 1 illustrates that pathways that coordinate utilization of the gas and electric systems, such as the Hybrid Electrification scenario, show lower overall levels of challenge. In contrast, pathways that rely more heavily on emerging technologies, including renewable gas – or that rely entirely on electrification and gas decommissioning strategies by 2050 - face challenges across several dimensions.

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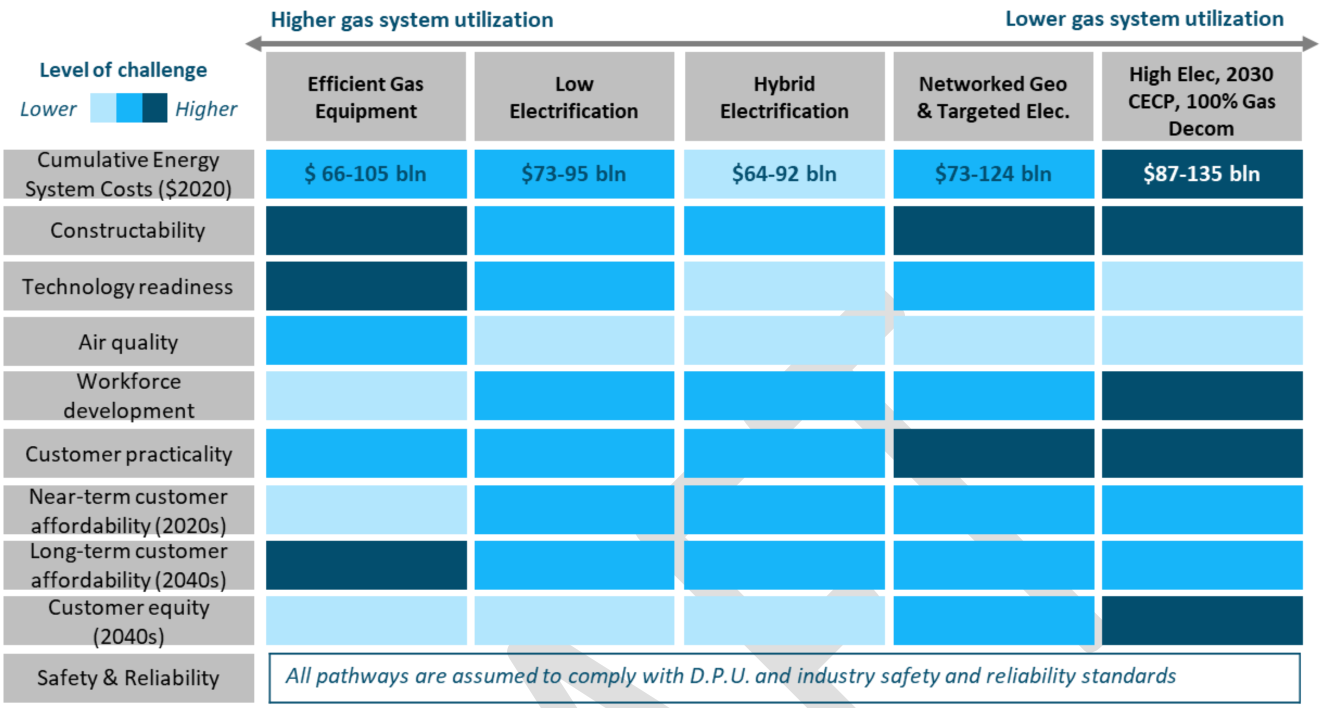
[6] The five LDCs reflected in this study include: Berkshire Gas, Eversource Energy, Liberty Utilities, National Grid, and Unitil.

[7] D.P.U. 20-80 at 1

[8] Consistent with the 2050 Roadmap, remaining emissions in 2050 are assumed to be netted off by carbon sinks to achieve carbon neutrality by 2050.

[9] Chapter 8 of the Acts of 2021, "An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy"

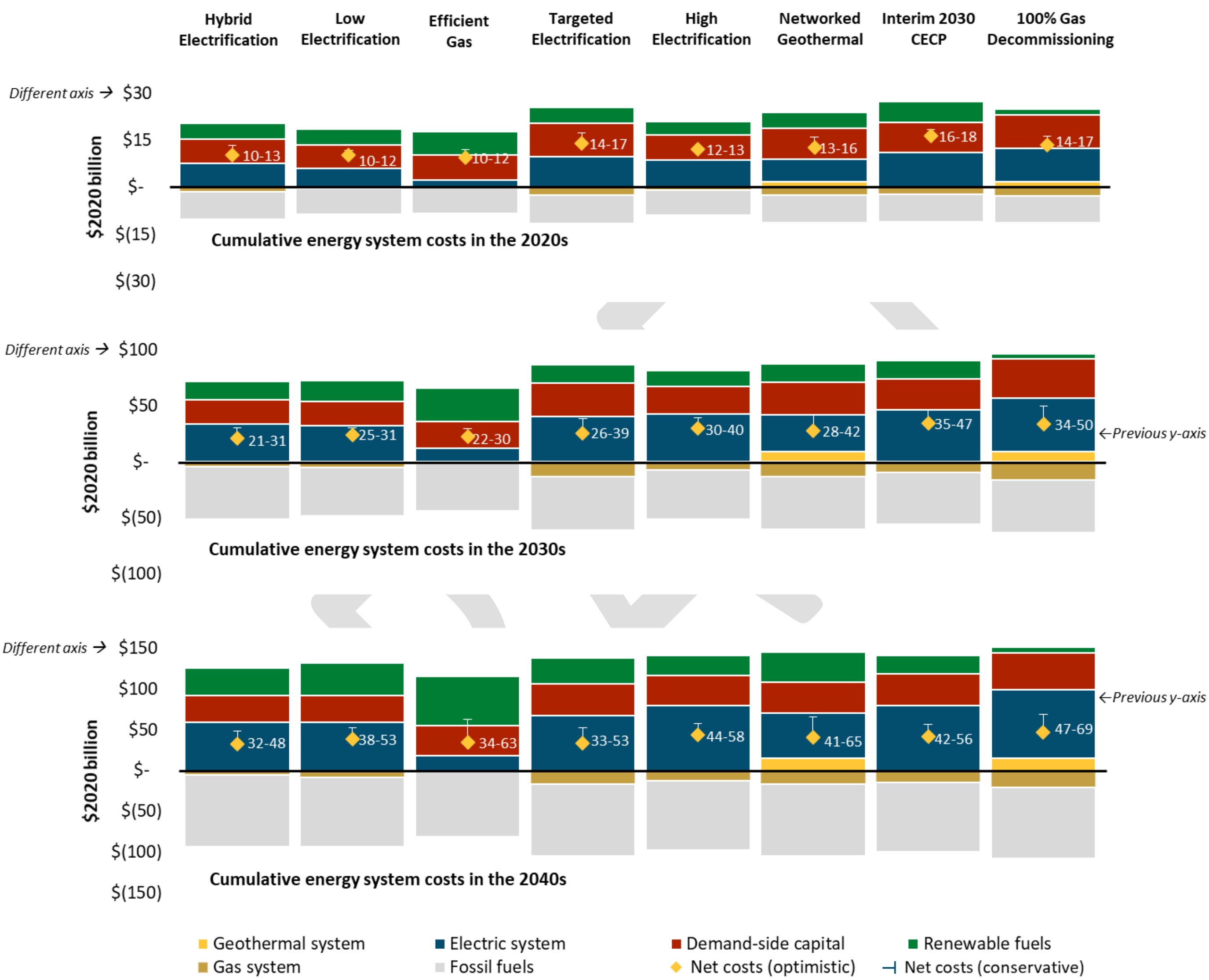
Figure 1. Decarbonization scenario results across multiple evaluation criteria.



Metric	Definition
Cumulative Energy System Costs	The cumulative (simple sum) incremental annual cost of energy supply and delivery infrastructure, end-use equipment, and fuel costs, net of fuel savings, relative to the Reference scenario, 2020 - 2050. Higher costs implies a higher level of challenge. Costs are shown in real 2020 dollars, billions.
Constructability	The pace and scale of electric and gas sector infrastructure additions. Scenarios with higher overall infrastructure requirements of gas and/or electric equipment face a higher level of challenge.
Technology readiness	The extent to which a pathway relies on technologies that are commercially available. Renewable gases are less technologically mature; scenarios that rely on them face a higher level of challenge on this metric.
Air quality	Air quality is estimated based on 2050 fuel combustion in each scenario. Scenarios with more electrification have lower levels of combustion emissions and are assumed to result in lower levels of air quality challenge.
Workforce development	Estimate of the scale of the LDC workforce that will need to transition roles. Scenarios with high levels of electrification imply a more challenging worforce transition to train, or re-train, skilled workers.
Customer practicality	The pace, scale and types of customer-side retrofits required to achieve decarbonization. Scenarios with higher levels of heat pump and building shell adoption require more extensive and coordinated customer retrofit initiatives.
Near-term customer affordability	The total cost of ownership (TCO), including upfront capital costs, for LDC customers who adopt building decarbonization measures in the 2020s. Electrification is more costly for customers in the 2020s; indicating a higher level of challenge.
Long-term customer affordability	TCO for LDC customers who adopt building decarbonization measures in the 2040s. Increasing commodity costs of gas result in a higher level of challenge for scenarios relying heavily on gas.
Customer equity	The cost impact on LDC customers who do not adopt decarbonization technologies ("non-migrating"). Higher income customers are more likely to migrate than lower-income customers, absent policy intervention. Higher costs for low-income and non-migrating customers implies a higher level of customer equity challenge.
Safety & Reliability	All pathways are assumed to comply with D.P.U. and industry natural gas and electric safety and reliability standards. Those standards will need to be evaluated over time depending on how decarbonization proceeds.

Achieving net-zero emissions requires early investments in the energy system; those investments must increase over time as energy demand and supply transformations scale. Fossil fuel savings are significant in all pathways. Avoided gas system costs are small relative to the investment costs required in other sectors (Figure 2).

Figure 2. Cumulative (simple sum) energy system costs relative to reference by decade ($2020, billion)



In the 2020s, costs are driven by a ramp-up in demand side investments like heat pumps and building shell retrofits, as well as initial investments in networked geothermal systems. Incremental energy supply costs are also incurred in the 2020s, particularly via investments in renewable electric supply and initial procurements of renewable fuels.

By the 2030s, costs scale alongside the energy system transformations necessary to achieve decarbonization. Scenarios with reduced gas system utilization see gas system savings but result in larger investment needs in the electric system. Electrification of heating adds large new winter peak demands to the New England electric system. In order to meet those heating demands, new firm generation resources are needed, capable of providing power during winter cold snaps that can coincide with periods of low wind and solar production. Renewable fuel investments also increase substantially as the Commonwealth's 2030 and 2040 emissions targets bind. Gas system savings begin to accrue in this decade, with the largest savings achieved in scenarios with targeted electrification and networked geothermal strategies.

The 2040s show the largest distinctions across scenarios, based on relative levels of energy demand and supply-side transformations. Costs in the 2040s demonstrate that electrification has a critical role in decarbonizing heating in Massachusetts. Absent substantial investments in electrification, which require significant constructability, large investments in renewable fuels are required that entail significant cost and technology commercialization risk.

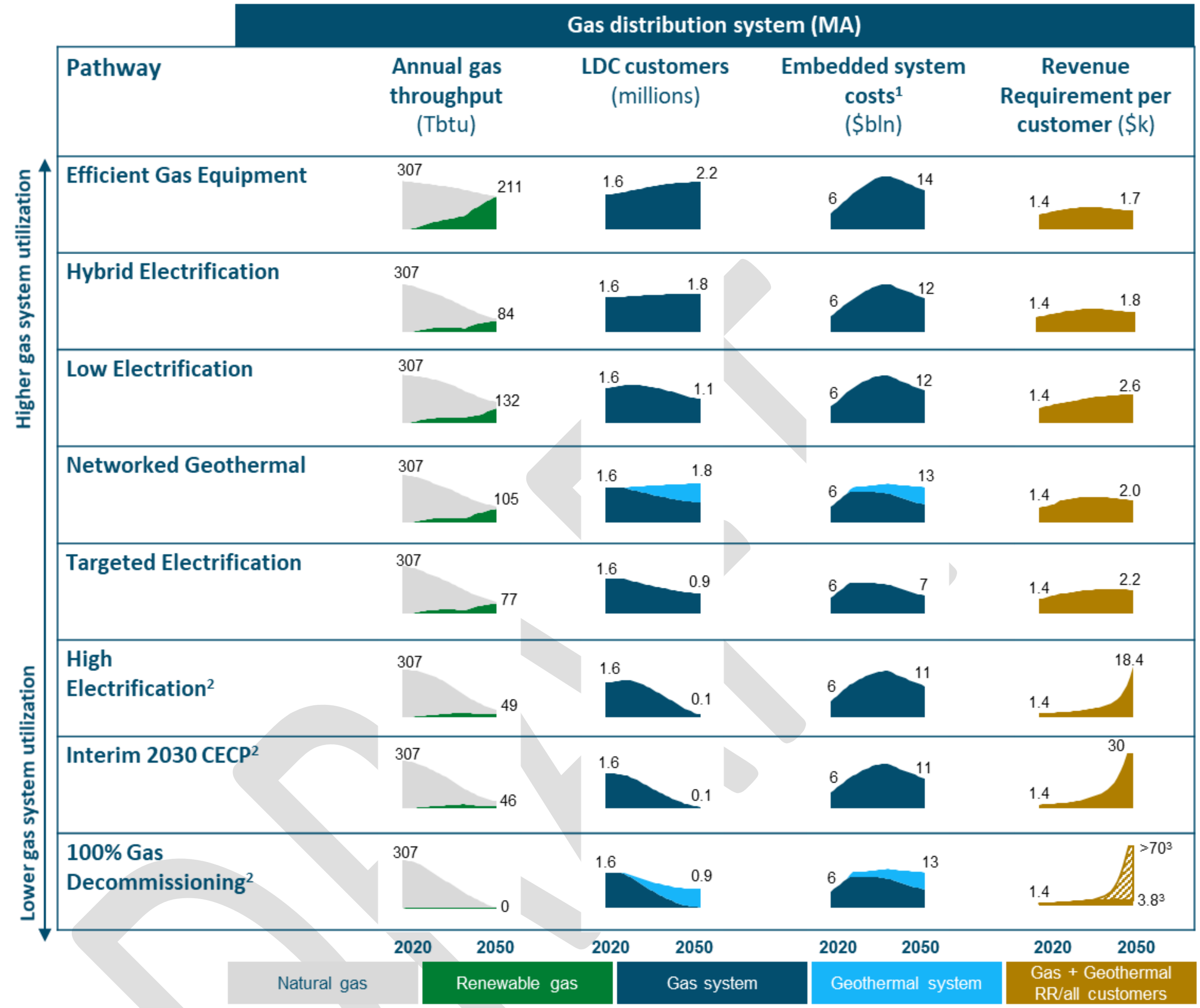
A promising strategy to balance the benefits and challenges of electrification and decarbonized fuels is hybrid electrification. Hybrid electrification both mitigates electric infrastructure expansion challenges and limits the use of decarbonized fuels. A hybrid strategy reduces the cumulative cost of achieving net-zero GHGs through 2050 by between $23-43 billion relative to scenarios that primarily rely on all-electric strategies and substantially reduces the amount of renewable fuels that would need to be procured relative to strategies with low levels of building electrification.

All pathways imply transformational change for the LDCs and their customers, raising substantial cost recovery and potential stranded cost challenges for those scenarios with high levels of customer departures.

Achieving net-zero requires a transformation of customer end-uses, energy supply and networks. As Figure 3 illustrates:

- **Gas throughput falls and LDC service to customers changes over time**. Gas throughput declines in all decarbonization pathways as heating and other demands are reduced via energy efficiency and electrification. The LDC customer base varies from continued growth in the Efficient Gas Equipment scenario to a near-elimination of customer base in the High Electrification and Interim 2030 CECP pathways. In the 100% Gas Decommissioning and Networked Geothermal pathways, the LDCs transition to provide heat to a subset of their customers via networked geothermal systems. In the Hybrid Electrification scenario, customers rely on electricity for most of their heating needs supplemented by gas heat during peak demand periods.
- **Decarbonization likely requires a transformation of gas supply**. All scenarios entail the use of some renewable gases to achieve net zero emissions in Massachusetts by 2050, although the anticipated costs and quantities of those gases vary significantly by pathway. The Efficient Gas Equipment scenario requires highest levels of renewable gases, including conversions of portions of the gas network to 100% hydrogen service to the industrial sector.
- **Scenarios with decreased utilization of the gas system face substantial embedded cost recovery challenges and may result in stranded costs**. The Massachusetts' gas system is characterized by long-lived assets that require ongoing investment to ensure safety and reliability. The LDCs are currently implementing system upgrades under the Gas System Enhancement Plan (GSEP) and those investments will increase the cost of the gas system and LDC revenue requirements over the coming decade. As customers depart the gas system in scenarios with high levels of electrification and customer migration, the costs for remaining customers increase to impractical levels. Those increases can be partially mitigated via measures like targeted electrification that reduce the remaining rate base of the gas system by up to $4 billion in 2050. However, the degree to which cost savings from targeted electrification can be achieved is uncertain.

Figure 3. Transformations in the gas system by pathway (2020 – 2050). Costs are shown in real $2020.



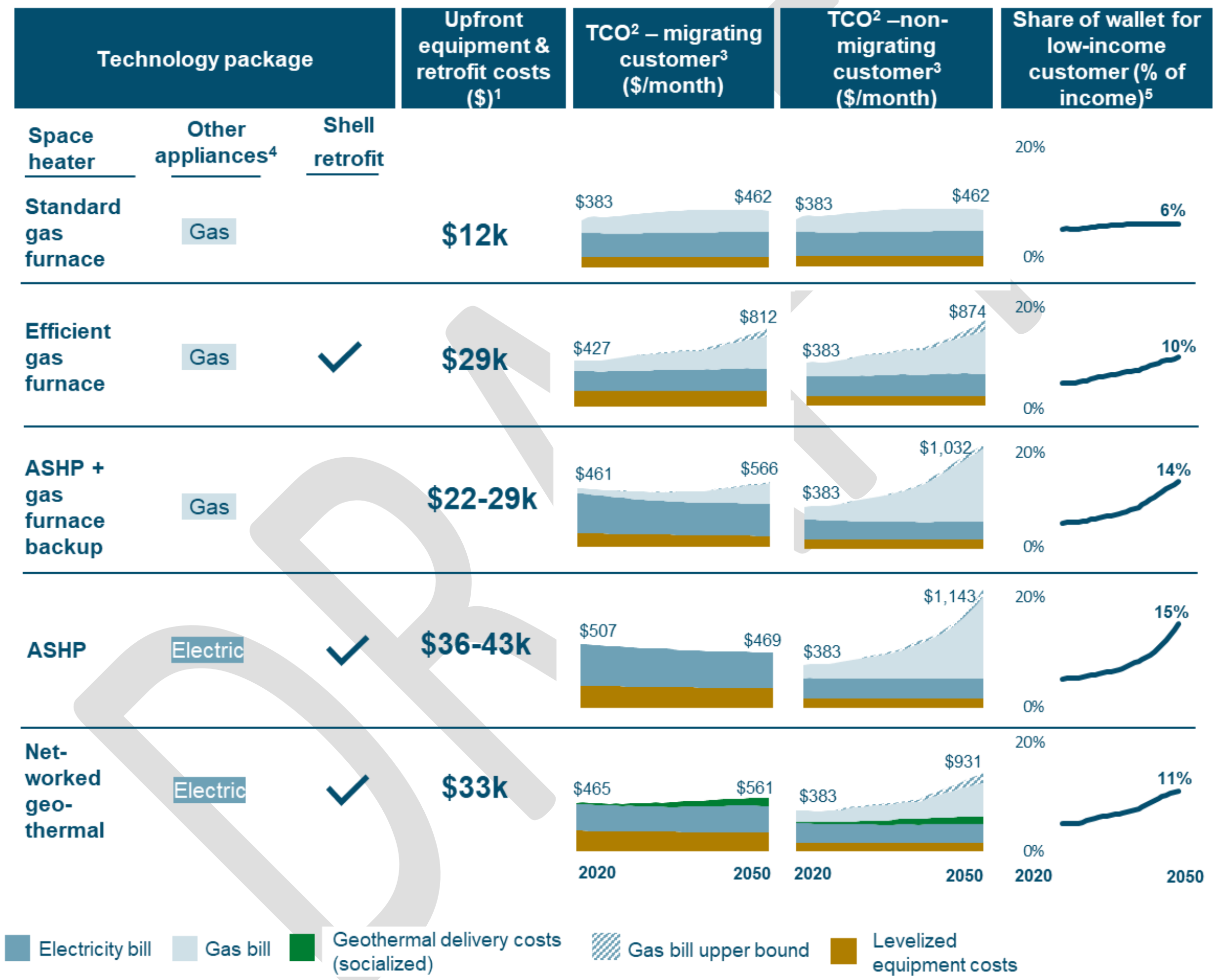
¹Expressed as gas plus geothermal system rate base assuming optimistic cost reductions & optimistic geothermal costs.
²Scenarios with lowest gas system utilization bear the risk of ending up with embedded system costs that can no longer be recovered.
³100% Decommissioning pathway shows Revenue Requirement if costs are shared over all geothermal customers (bottom), versus if costs are shared over gas customers only (top).

New regulatory support strategies will be needed to minimize customer cost impacts, regardless of which pathway, or combination of pathways, are pursued.

Consumers are at the center of Massachusetts' decarbonization goals because their decisions about when and how to adopt electrification and efficiency measures affects the nature, scale, and magnitude of electric and gas system transformations. Pathways that achieve rapid electrification in particular imply high levels of customer support, including financial incentives to reduce upfront capital costs, and/or mandates to require electrification. Targeted electrification strategies may also require early retirement and replacement of customer equipment.

Figure 4 illustrates the total cost of ownership, including energy bills and upfront costs, for both migrating and non-migrating customers per major decarbonization technology type for an example single family customer, as well as an estimated "share of wallet" for low-income customers. A common set of challenges facing customers across decarbonization pathways are the upfront costs and operating costs of decarbonization options. For example, in the near-term, electrification carries high upfront and operating costs. Absent supportive policy initiatives these incremental costs represent a substantial barrier to achieving adoption of electrification measures. Longer-term, electrification becomes more attractive compared to other decarbonization alternatives as costs for technologies like Air-Source Heat Pumps (ASHPs) fall and gas rates increase at a faster pace than electric rates in all scenarios.

Figure 4. Overview of customer costs for an average, pre-1940 single family home. Gas bills are based on Eversource (NSTAR) rates.



¹ Includes cost of building shell upgrade (if applicable), space heating equipment, water heating equipment and cooking & clothes drying appliances.

² TCO = Total Cost of Ownership. Includes both energy bills and levelized cost of equipment.

³ A "migrating" customer is a customer adopting the technology package. A "non-migrating" customer is a customer not adopting the technology package. The charts include rates for the scenario shown in *italics*.

⁴ 'Other appliances' include: water heater, clothes dryer, and cooking. Chart does not include transportation electrification bills.

⁵ Charts show energy bill effects for low—income, non-migrating customers. A low income customer is defined as a customer with an income of 60% of the Massachusetts median. Low-income customers are assumed to receive a 25% discounted gas rate. Chart includes energy bills only, excluding levelized equipment costs.

LDC customer bills rise in all pathways due to increases in both the delivery and commodity components of gas rates. Customer cost impacts are more balanced in scenarios that rely on a combination of electrification and gas, although regulatory reforms are needed to support these options.

- **Delivery costs** rise in all scenarios due to GSEP and other system upgrade initiatives. However, LDC customer impacts are most acute in scenarios with high levels of electrification as the cost of gas infrastructure is spread over rapidly declining utilization. Under current cost allocation, this would result in inequitable outcomes where remaining customers pay a disproportionate share of costs. Such an outcome is particularly concerning for lower income customers who are less able to reduce their exposure to gas rate increases through electrification given upfront cost.
- **Commodity cost** increases are highest in scenarios with lower levels of electrification. Gas commodity cost increases are relatively small in the near-term but grow over time as the Commonwealth's GHG emissions targets become more ambitious. In the later model years, those commodity costs can become so high as to shift consumer incentives decisively towards electrification.

Conclusions and Recommendations

Despite long-term uncertainty on the direction of decarbonization, there are several low regret decarbonization technologies used across scenarios:

- **Energy efficiency** through building shell retrofits and energy efficient equipment, especially for all-electric buildings or buildings using large amounts of renewable gases. Energy efficiency measures decrease the impacts of electrification on the electricity system and reduce demands for expensive and currently non-commercialized renewable gases.
- **Building electrification,** where feasible, including strategies for all-electric residential new construction and hybrid electrification strategies in existing buildings. Hybrid building electrification strategies appear promising in Massachusetts' cold winter climate. Programs to scale the installation of hybrid heat pumps, including as a gas conservation measure and an electric system resource, are warranted based on this commonality.
- **Biomethane** from wastes and residues, including from landfill gases. Most scenarios blend up to 5-10% of renewable fuels in the gas distribution pipeline without substantially increasing the cost of gas supply by 2030, to support achievement of the Commonwealth's GHG goals.
- **Renewable electricity.** All scenarios require a substantial transformation of the electric sector, doubling or tripling current generation capacity to deploy more renewable resources to reach net zero emissions, regardless of the level of electrification pursued. This includes the installation of thousands of megawatts of new offshore and onshore wind, utility-scale and distributed solar and new transmission to deliver renewables to the Commonwealth.

In addition to these common strategies, several decarbonization technologies are worth further research and development to better understand their costs and resource potential.

- **Hybrid system operation** pilots and programs, similar to those underway in Canada and the United Kingdom, could address open questions with respect to the operation of these systems. Strategies to coordinate operation in non-overlapping gas and electric service territories are needed given how common that arrangement is in Massachusetts.
- **Targeted electrification to enable decommissioning of gas distribution assets** may offer opportunities for savings on the gas distribution system, potentially reducing the cost impacts of electrification on remaining customers. As noted above, there are many open questions about how targeted electrification could be achieved as envisioned in this study. Developing pilots would help to clarify the opportunities and challenges of achieving targeted electrification in Massachusetts.

- **Networked geothermal systems** have the potential to provide renewable decarbonized heat without causing large electric peak demands in winter, while leveraging the LDCs' existing expertise and workforce. Eversource and National grid both have ongoing pilots that will help to reduce uncertainties around the feasibility and long-term cost of this option at scale.
- **Renewable hydrogen** has a role in all scenarios modeled, for potential use in providing electric sector firm capacity, for blending into the gas distribution system, or for use in medium- and heavy-duty transportation. However, renewable hydrogen has not been deployed at the scale envisioned in this analysis, and questions remain around the cost of producing, distributing and storing hydrogen in New England. Programs to blend small amounts hydrogen in the LDCs' systems could be a promising next step.

Balancing across many considerations, decarbonization pathways that strategically use the state's gas infrastructure alongside and in support of electrification are likely to carry lower levels of challenge.

A coordinated gas and electric decarbonization strategy, utilizing a diverse set of technologies and strategies, is likely to be better able to manage the costs and feasibility risks of decarbonization than scenarios that rely more heavily on single technologies or strategies.

Under all pathways, the LDCs, the D.P.U., and policymakers will need to manage customer costs and energy bills to ensure that the clean energy transition in Massachusetts is affordable and equitable to all.

The Consultants recommend that the LDCs together with the D.P.U., begin implementing decarbonization strategies and regulatory reforms to support the Massachusetts climate goals.

The LDCs should explore mechanisms to coordinate use of the gas and electric systems to minimize the combined cost of decarbonizing building heating needs for customers. This includes developing strategies and funding to increase electric technology adoption, authorization for renewable fuel procurement, as well as regulatory support for new rate designs and cost-recovery mechanisms that support decarbonization. These regulatory designs are explored further in Part II of the Consultant Independent Report.

1. Introduction

Purpose & Scope of the Report

About this Report

The Commonwealth of Massachusetts is committed to reduce Greenhouse Gas (GHG) emissions to "Net Zero" by 2050, in alignment with the goals of the Paris Agreement[10], which calls for a global effort to keep global temperature rise "*well below 2 degrees Celsius*" and to "*pursue efforts to limit the increase to 1.5 degrees Celsius*." Specifically, in March of 2021, Governor Charlie Baker signed into law Senate Bill 9 that formally codifies Net Zero into law, together with interim goals for emissions reductions of 50% GHG reduction by 2030 and 75% GHG reductions by 2040 compared to 1990 levels.[11]

To explore implications of the Commonwealth's commitment to combatting climate change, the Executive Office of Energy and Environmental Affairs released a 2050 Decarbonization Roadmap ("the Roadmap") in December 2020. The Roadmap found that the Commonwealth can achieve net zero emissions by 2050, but that the way in which Massachusetts pursues its climate goals implicates the costs, human health, risks and broader environmental impacts associated with decarbonization.[12]

In the context of the Roadmap and the Commonwealth's commitment, the Massachusetts Department of Public Utilities ("the Department") in October 2020 opened Docket 20-80 with the intention to *"examine the role of Massachusetts gas Local Distribution Companies ("LDCs") in helping the Commonwealth achieve its 2050 climate goals"* and to *"explore strategies to enable the Commonwealth to move into its net zero GHG emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth."*[13] The Department directed the LDCs to issue a Request for Proposals ("RFP") for an independent consultant to support the LDCs in this investigation.

This Report provides the Consultants' analysis of the role of LDCs in achieving the Commonwealth's climate goals, which includes identifying decarbonization pathways for the gas distribution system to transition in support of Massachusetts' net zero commitment, implications of these pathways for the Commonwealth, the LDCs and their customers, and potential policies and regulatory strategies that would help support this transition.

Scope

As ordered by the Department, the scope of this Report requires the Consultants to review decarbonization pathways identified in the Roadmap, to identify any pathways not examined in the Roadmap, and to perform a detailed study of each LDC that analyzes the implications and feasibility of all pathways.[14] The Department further noted that the Report should *"compare and contrast the implications*

[10] The Paris Agreement is an international treaty on climate change adopted at the United Nations Framework Convention on Climate Change (UNFCC) Conference of the Parties (COP) in Paris, on December 12, 2015.

[11] Senate Bill 9: An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy

[12] Simultaneous with the Roadmap, the Commonwealth released an update to the Clean Energy and Climate Plan for 2030 which states that emissions from natural gas, fuel oil and propane in the Building sector, accounting for almost a third of the Commonwealth's GHG emissions, must begin to steadily and permanently decline.

[13] D.P.U. Docket 20-80 at 1.

[14] D.P.U. Docket 20-80 at 5.

of proposed policies upon each LDC and upon the LDCs as a whole and result in meaningful discussions and recommendations."[15]

For all decarbonization pathways, the Department requested:

- A forecast of costs and economy-wide GHG emissions reductions involved in transitioning the natural gas system, including:
    - A discussion of possible mechanisms, methodologies or policies to address the recovery of costs and mitigation of costs and impacts for customers, especially low-income customers;
    - A forecast of electrification strategies as well as other strategies identified through the analysis;
    - A transparent depiction of key assumptions and a calculation of GHG emission reductions;
- A discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reduction and timing;
- Proposed recommendations to reduce GHG emissions from the sale and distribution of natural gas to meet applicable goals in relation to the Roadmap, with specific initiatives, actions and interim milestones.

These objectives are embedded in the study framework developed by the Consultants, as further described in Chapter 2. The Report consists of two parts:

- Part I describes the analysis of decarbonization pathways, implications of these pathways and the Consultant's recommendations for LDCs that support the Commonwealth's climate goals;
- Part II discusses possible mechanisms, methodologies or policies to address the recovery of costs and mitigation of impacts for LDC customers.

This Report focuses on the transition of the natural gas distribution system and the role of LDCs in supporting the Commonwealth's objectives. Since the majority of natural gas in Massachusetts is consumed in the Buildings sector, building decarbonization is the primary focus of this analysis. However, in assessing potential transformations of the Buildings sector, the Consultants analyzed impacts across all sectors of the economy, including the transportation, industry, and electric sectors.

In addition to this Report, each LDC is submitting a proposal to the Department that includes plans for helping the Commonwealth achieve its 2050 climate goals. As such, this Report is not an implementation plan. Instead, it provides the foundational analysis to the LDC-specific proposals, including a quantitative and qualitative assessment of decarbonization pathways and recommendations for possible mechanisms or policies to both support achievement of decarbonization and mitigate the cost impacts of decarbonization on LDCs and their customers.

Gas Distribution in Massachusetts

This report focuses on the following LDCs that provide natural gas service to customers in Massachusetts, including:

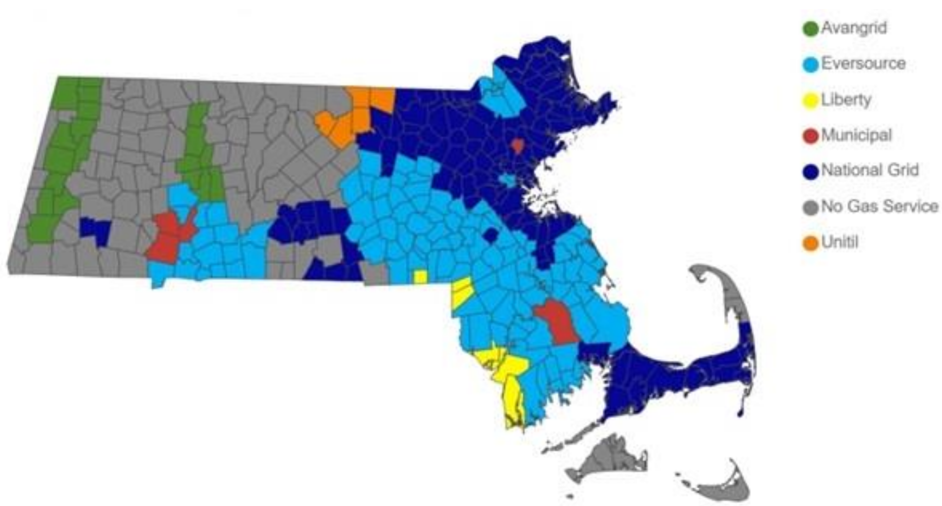
- Avangrid – The Berkshire Gas Company
- Eversource Energy – Eversource Gas of Massachusetts (formerly, Columbia Gas of Massachusetts) and NSTAR Gas Company
- Liberty Utilities – New England Gas Company and Blackstone Gas Company

[15] Idem.

- National Grid – Boston Gas Company[16]
- Unitil – Fitchburg Gas and Electric Light Company

In addition to these utilities, there are four municipal gas companies active in the Commonwealth that fall outside the scope of this Report.[17] Figure 5 provides an overview of the natural gas service territory in Massachusetts by LDC.

Figure 5. Natural gas service territory per LDC.



As recognized by the Department, "*each LDC is distinct and has different capabilities and limitations within its own service territory.*" Thus, to provide the appropriate background and context for the Consultants' analysis of the decarbonization pathways, this Report provides an overview of the current role of natural gas in Massachusetts and a detailed assessment of the distinct LDC characteristics, which were incorporated into the Consultants' quantitative and qualitative analyses.

Study Process

In April 2021, the LDCs selected Energy & Environmental Economics (E3) and ScottMadden to be the independent consultants for this study. In response to the RFP, the Consultants developed a robust analytical framework that includes: a summary of LDC characteristics, a quantitative and qualitative assessment of decarbonization pathways, the impact of those decarbonization pathways on LDCs, customers, the LDC and broader energy sector workforce, as well as identification of mechanisms that help safeguard ratepayer interests, with a particular focus on low-income customers. A full overview of this analytical approach is described in Chapter 2. To allow for a comparison with the Roadmap, the analytical framework and key assumptions are designed in a similar way to the analytical framework used in the Roadmap. However, the pathways modeled by the Consultants are not identical to those of the Roadmap as a result of several distinct modeling differences described further in Chapter 2.

The scenarios reflected in this Report, and the underlying analysis, reflect input from many stakeholders. At the start of this project, the LDCs crafted a stakeholder process with the Attorney General and other

[16] Throughout this Report, data is shown for both Boston Gas and the former Colonial Gas Company.

[17] The municipal gas companies, which are not within the scope of this Report, include Holyoke Gas & Electric; Middleborough Gas & Electric; Wakefield Municipal Gas & Light; and Westfield Gas & Electric Light.

stakeholders that included the development and implementation of a stakeholder engagement plan ("SEP").[18] The LDCs retained Environmental Resources Management ("ERM") to support and facilitate the stakeholder process. Through ERM, the LDCs have engaged stakeholders through a variety of methods, including monthly meetings, special issue workshops, and one-on-one conversations. In addition, as part of the analytical approach, the Consultants engaged with stakeholders to identify alternative decarbonization pathways not included in the Roadmap. A summary of the stakeholder process is provided in Chapter 2, full documentation of the stakeholder process is reported by ERM through separate documentation.

The Consultants and LDCs coordinated on the analysis and process of this Study on a regular basis, including through bi-weekly project management meetings, monthly Steering Committee meetings, and frequent deep-dive meetings to discuss interim analyses. All decarbonization pathways were established with input and support from LDCs. The assessment of implications of the decarbonization pathways as well as the recommendations are based on the Consultants' independent analysis and conclusions.

[18] This stakeholder engagement plan, along with all materials related to the stakeholder process, can be found on the Future of Gas website (www.thefutureofgas.com).

2. Approach

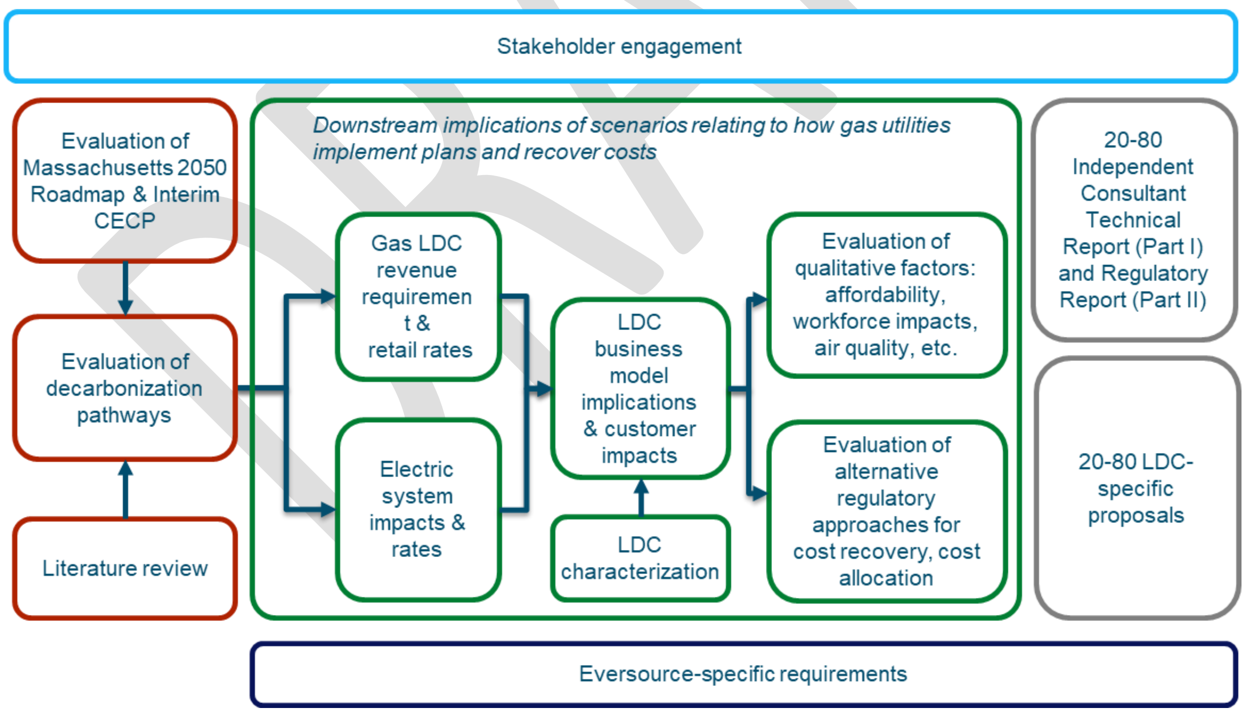
Study Framework and Evaluation Criteria

The Consultant's study framework included several distinct phases of analysis:

- An evaluation of the 2050 Massachusetts Roadmap and 2030 CECP;
- A literature review pertaining to transitional strategies for natural gas distribution systems;
- An evaluation of alternative pathways to achieving the Commonwealth's climate goals;
- A characterization of gas supply in Massachusetts;
- A characterization of individual LDCs and identification of key differences across LDCs;
- A quantitative assessment of the implications of decarbonization pathways on LDC operations and their customers;
- A qualitative assessment of the implications of decarbonization pathways;
- An evaluation of alternative policy and regulatory approaches that support the Commonwealth's climate goals.

In addition to these phases, the Consultants supported Eversource Energy in their filing of a Clean Energy Business Case Analysis required under the Columbia Gas Acquisition Settlement Agreement. The results of this Workstream are provided in a separate D.P.U. Docket and as such not included in this Report[19] Figure 6 provides a conceptual overview of the study framework.

Figure 6. Overview of study framework.



To address the key objectives laid out by the Department, the Consultants developed and examined distinct decarbonization pathways. To assess the implications and feasibility of each of these pathways,

[19] See D.P.U. 20-59 Docket.

the Consultants considered a broad set of evaluation criteria, analyzed through a combination of both quantitative and qualitative factors described in Table 1 below.[20]

Table 1. Evaluation criteria.

Evaluation criteria	Description
Energy system costs	The cumulative (simple sum) incremental annual cost of energy supply and delivery infrastructure, end-use equipment, and fuel costs, net of fuel savings, relative to a Reference scenario.
Safety	The extent to which natural gas and electric safety is maintained, per industry and D.P.U. standards. Note that in this analysis, all pathways are assumed to comply with D.P.U. and industry standards.
Reliability & Resilience	The extent to which natural gas and electric reliability & system resilience are maintained, per industry and D.P.U. standards. Note that in this analysis, all pathways are assumed to comply with D.P.U. and industry standards.
Constructability	The pace and scale of electric and gas sector infrastructure additions.
Technology readiness	The extent to which a pathway relies on technologies that are commercially available.
Air quality	The combustion of fuels, used as a proxy for indoor and outdoor air quality.
Workforce development	Estimate of the scale of the LDC workforce that will need to transition.
Customer practicality	The pace, scale and types of customer-side retrofits required to achieve decarbonization, and necessity or implication of building electrification mandates to achieve scenario outcomes
Customer affordability	The total cost of ownership for LDC customers who adopt building decarbonization measures.
Customer equity	The effect of LDC customer migrations on equity (across generations of LDC customers, migrating vs. non-migrating customers, and between rates classes)

Notably, each scenario is modeled to reflect a *safe* and *reliable* energy system in the Commonwealth per existing gas and electric standards, while achieving similar levels of *greenhouse gas reductions*. As such, these factors are not used as evaluation criteria to the same extent as the factors described above.

While the decarbonization pathways are compared against each other on these criteria, the intention is not to suggest that any one pathway should be considered a "preferred" strategy to transition the gas system. Instead, comparing the pathways allows for the identification of key commonalities, differences and implications across decarbonization strategies, to be incorporated into future policy-making, regulation and planning.

The identification of these evaluation criteria was informed by the D.P.U. 20-80 Order[21], recent Massachusetts climate legislation[22], review of decarbonization literature, as well as discussions with LDCs and stakeholders. Once evaluation criteria were identified, the Consultants utilized various metrics from the scenario modeling to frame the discussion of pathway implications. In some cases, the evaluation of components, or requirements, of each scenario were utilized as a proxy for otherwise qualitative

[20] The implications for Environmental Justice communities as defined by the Commonwealth (based on income, minority population, and/or English isolation) are discussed throughout the Report and within the context of various qualitative factors, including customer affordability, customer equity, customer practicality, workforce development, and air quality.

[21] The independent consultant's report shall: *"Present a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing"*

[22] MA Senate Bill 9, section 15 (1a): *"[T]he 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"*

considerations, to provide insights into the magnitude and pace of change implied by different decarbonization pathways.[23] This approach allows important issues that may not be explicit outcomes of the modeling to be compared across scenarios over time against business-as-usual (i.e., Reference) and determine the relative degree of challenge required to achieve the parameters assumed in each scenario. Decarbonization strategies with a lower degree of challenge are likely to be more feasible to implement.

Chapter 5 provides a summary of key observations from the Consultant's quantitative and qualitative assessment for all evaluation criteria, including an overview of potential feasibility challenges across pathways relative to Reference. Based on the assessment of both quantitative and qualitative factors, the Consultants evaluated a set of possible regulatory mechanisms, methodologies and initiatives that could support the Commonwealth's climate goals and mitigate possible unintended consequences of different decarbonization strategies, as described in detail in Part II of this Report.

Stakeholder Engagement

Stakeholder input and feedback are critical components of the stakeholder engagement process (SEP) associated with the Future of Gas. In May 2021, the SEP was developed in collaboration with stakeholders. Since then, ERM and the Consultants have received and responded to more than 800 comments. The comments are varied and include themes such as affordability, transition timeline, proposed scenarios, renewable energy, equity, workforce considerations and others.

Several mechanisms were employed to encourage robust and meaningful engagement:

- Email: For those with reliable internet access, a dedicated email address was established in May 2021.
- Web: A website (www.thefutureofgas.com) was launched in June 2021. The site is the primary resource for information related to the Future of Gas proceeding and related stakeholder engagement process. Updated bi-monthly, the site features recordings of monthly stakeholder meetings, customer webinars and videos as well as meeting summaries and presentations, among other stakeholder and customer resources. Recognizing that language barriers exist, customer videos and webinar recordings have been translated from English into four additional languages and associated dialects (Spanish, Vietnamese, Chinese and Portuguese) predominantly spoken in Massachusetts.
- Phone: For stakeholders without access to the internet, a dedicated toll-free telephone number was also established in May. This line is monitored by ERM and each call is returned to accept questions and comments.

Questions and related responses documented via all of the contact vehicles above have been linked on the Future of Gas website monthly to demonstrate the transparency of the process. Over the past nine months, ERM has managed and facilitated two stakeholder engagement process planning meetings, eleven stakeholder meetings with participation from more than 100 unique individuals representing diverse stakeholder groups across the Commonwealth; one scenario design workshop, and one two-hour technical session to review the set of scenarios developed by E3. Additional outreach included 1:1 meetings with stakeholder groups representing climate advocates, customer advocates, business interests, Labor and others who have varying interests in the outcome of the proceeding. These meetings coupled with customer webinars and videos have resulted in diverse perspectives being shared

[23] By way of example, the number of gas LDC customers over time and residential heating equipment stocks turnover are used to inform the discussion of customer fuel choices in the Customer Practicality section. In addition, the level of O&M expenses on the gas system are used to identify potential implications to the gas system workforce.

throughout the process. In addition, the LDCs held two customer webinars for customers to learn, ask questions, and provide feedback about the future of gas proceeding, the Commonwealth's net zero goals, and the technologies available to achieve these goals.

Documentation of the stakeholder process is provided by ERM through separate documentation. ERM's report includes comments and feedback shared by customers and stakeholders, a summary of 1:1 interviews, participant lists, a breakdown of topics and other supporting documentation.

Pathway Development

Design of Decarbonization Pathways

The pathways described in this Report show distinct possible futures of how the Commonwealth could achieve its carbon goals, including pathways developed in the Roadmap and alternative pathways developed for this Report. The alternative pathways were developed with input from both LDCs and stakeholders, with the aim to evaluate a broad and distinct set of decarbonization scenarios. As such, the pathways are designed to highlight different strategies to achieve decarbonization in Massachusetts, with particular emphasis on pathways to decarbonize natural gas in the Buildings sector.

What defines a "good" decarbonization pathway? A pathway should:

- Reach the common objective of Net Zero by 2050 while continuing to provide safe and reliable energy services;
- Do so in a manner that provides for meaningful distinctions between pathways;
- Consider the energy transition across all economic sectors;
- Be *possible* to achieve;
- Be the "best version of itself", meaning that pathways should reflect logical and consistent choices within the constraints of the pathway objectives, and that no pathway should be designed *ex ante* to serve as a strawman against which a preferred outcome is identified.

It is important to note that analyzing decarbonization pathways out to 2050 involves a multi-decade horizon that is inherently assumptions-driven and uncertain across several factors including cost, consumer behavior, technology development, deployment, and other factors discussed in this Report. E3's approach to pathway analysis captures key uncertainties by providing sensitivity analysis and ranges of costs of plausible outcomes; noting that not all uncertainty can be quantified in models. In doing so, E3 makes a clear distinction between "pathways" and "sensitivities":

- Pathways explore distinct *physical infrastructure transitions* to achieve economy-wide decarbonization;
- Sensitivities vary *key assumptions* to test the robustness of scenario findings against uncertainties.

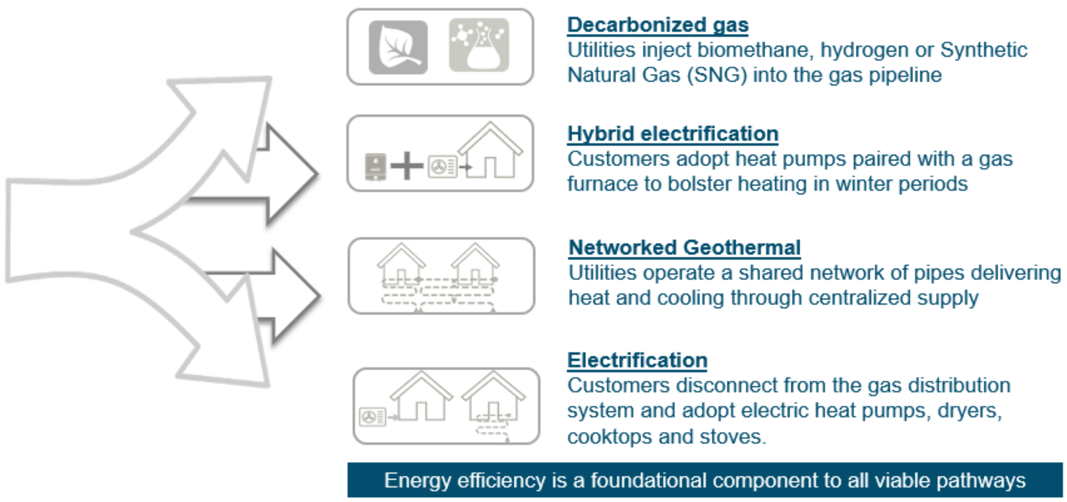
Decarbonization pathways are not forecasts, nor do they result in a single preferred solution. Instead, by examining multiple pathways, this type of analysis can be used to identify and compare key features of different plausible futures and their relative cost, feasibility, and risks, using the best available information today. A portfolio of measures that achieves the Commonwealth's decarbonization goals may include aspects of *multiple pathways*, as well as other strategies that may emerge in the coming decades.

Deep Decarbonization Pathways Literature Review

E3 conducted an extensive literature review of decarbonization strategies studied and implemented in the U.S. and abroad, looking at over 60 studies that represent perspectives on a range of topic areas and geographic diversity. The detailed findings of the literature review are provided in Appendix 2.

The literature review uncovered several decarbonization strategies for buildings and natural gas end-uses commonly found in studies exploring how net zero emissions or other deep decarbonization targets can be achieved (Figure 7). These pathways are not mutually exclusive; in fact, a combination of these strategies may be needed to cost-effectively decarbonize natural gas end-uses given the variety of building types, heating demands, and availability of technologies. Energy efficiency is a foundational component of all decarbonization strategies, and Massachusetts has long been a U.S. leader in achieving energy savings through efficiency programs. While most decarbonization pathways deploy some combination of emerging technologies, clean electricity, and renewable gas, energy efficiency underpins all these strategies by reducing the overall amount of energy and capacity needed, such that alternative technologies can effectively meet energy needs.

Figure 7. Common decarbonization strategies.



Notably, the Consultant's review of existing studies indicated that 100% decommissioning of the gas system, one of the pathways analyzed in this Report, has not yet been studied or implemented in any other jurisdictions, either in the U.S. or abroad. In addition, the Consultants noted that detailed studies on how decarbonization pathways affect customers, and particularly low- or middle-income customers, are often lacking. This perspective is specifically woven into the evaluation criteria assessed for this Report.

The Role of Gas in Cold Climate Decarbonization Strategies

The literature review performed by the Consultants highlighted some key considerations for the role of the gas system for decarbonization pathways in cold weather, which relate to gas system considerations in the Commonwealth. These considerations were considered in constructing a diverse set of decarbonization strategies, as described in the following section.

- *Peak heat*. In cold climates, gas systems serve substantially higher peak energy demands than electricity systems. Converting large amounts of gas heating to all-electric solutions therefore has the potential to cause substantial electric system peak demands, shifting the electric system from a summer peaking system to a winter peaking system, with implications for distribution, transmission, and generation infrastructure.[24,25,26] Decarbonization strategies that continue to

[24] E3 & EFI (2020) Net-Zero New England: Ensuring Electric Reliability in a Low Carbon Future

[25] The Brattle Group for Coalition for Community Solar Access (2019) Achieving 80% GHG Reduction in New England by 2050

[26] Imperial College (2018). Analysis of Alternative UK Heat Decarbonisation Pathways

use the gas system, particularly as a capacity resource using dual fuel or hybrid electrification, mitigate these impacts.[27,28,29]

- *Electric reliability and resilience*. Gas generation resources, running on renewable fuels, can support electric reliability in the context of deeply decarbonized electricity systems. Studies have shown that annual gas generation falls substantially in decarbonization scenarios, but that, absent breakthroughs in the cost of new clean firm resources, existing generation capacity is maintained, or even grows, to support reliable electric service.[30, 31] That capacity is used to generate electricity when renewable output is low over a large geographic extent and loads are high, a condition that is expected in the winter in cold climates. In addition to reliability, studies have found that the gas network can support resilience in the energy system by offering features such as seasonal energy storage, underground infrastructure, and linepack.[32,33,34]
- *Hard to electrify sectors of the economy*. Certain end-uses, largely in the industrial sector, do not lend themselves well to electrification, particularly in high temperature industrial process heating[35]. These applications may see continued use of gas, either in the form of renewable gases (i.e., biomethane, synthetic gas, or hydrogen), or in combination with Carbon Capture and Storage (CCS).
- *Renewable gases.* Because biomethane and SNG have a similar molecular structure as natural gas (primarily composed of methane, or CH_4), they can be blended into the existing natural gas distribution pipeline without technical constraints, as long as the biomethane supply meets pipeline quality standards. In addition, hydrogen gas (H_2) can be blended with natural gas to a limited extent without requiring upgrades to the gas distribution system or customer end-uses. At the time of this study, seven utilities across the U.S. had set renewable gas blending targets, and 14 utilities had established renewable gas programs, including voluntary programs, pilots, and tariffs.

Overview of Pathways

The Consultants designed and analyzed eight decarbonization pathways:

- Three pathways are inspired by scenarios defined as part of the Roadmap and interim 2030 CECP: "High Electrification" (inspired by "All Options"), "Low Electrification" (inspired by "Pipeline Gas") and "Interim 2030 CECP." Note that the pathways are not *identical* to those analyzed in the Roadmap as a result of differences in modeling approaches described in Chapter 2 and adjustments to accommodate 2021 climate legislation updates that affect interim GHG reduction targets.

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[27] Pöyry (2018). Fully Decarbonizing Europe's Energy System by 2050

[28] MaRS Cleantech (2018): Future of Home Heating

[29] European Commission (2018): METIS Studies, Study S6. Decentralised heat pumps: system benefits under different technical configurations.

[30] See, for instance: European Commission (2020). Towards Net zero Emissions in the EU Energy System by 2050. This Study provides a comparative analysis across 14 deep decarbonization studies, noting that 9 out of 14 studies assume a remaining role for thermal capacity in the 2050 electricity mix.

[31] Fraunhofer Institute (2020). Paths to a Climate-Neutral Energy System.

[32] Guidehouse for National Fuel Gas Distribution Corporation (2021) Meeting the Challenge: Scenarios for Decarbonizing New York's Economy

[33] See, for instance: Clegg, S. & Mancarella, P (2016). Storing renewables in the gas network: modelling of power-to-gas seasonal storageflexibility in low-carbon power systems. The Institution of Engineering and Technology.

[34] Imperial College London (2020). The flexibility of Gas: What is it Worth?

[35] See, for instance: McKinsey (2018). Decarbonization of industrial sectors: the next frontier

- Five alternative pathways were designed based on LDC and stakeholder input that show distinctly different options of achieving the Commonwealth's climate goals, with the primary source of variation being the building sector heating transition within the Commonwealth.

Importantly, all pathways modeled by E3 comply with Massachusetts climate legislation. Similar to the Roadmap, pathways are assumed to reach gross emissions targets of 90% compared to 1990, or 9.5 $MtCO_2e$, by 2050. This means that residual emissions by 2050 are assumed to be removed from the atmosphere through negative emissions and carbon sequestration from the Commonwealth's natural and working lands, as analyzed in the Roadmap's Land Sector Report. In addition to the 2050 GHG target, all pathways reach gross emission targets of 50% by 2030 and 75% by 2040 compared to 1990. The three scenarios inspired by the Roadmap and Interim 2030 CECP have been altered by E3 to achieve these interim emissions targets, as these targets were announced after the release of the Roadmap.

In order to demonstrate a distinct set of decarbonization pathways specific to the Buildings sector that are markedly different from the ones analyzed in the Roadmap, all <u>alternative</u> pathways designed for this project reach 100% GHG reductions in the Buildings sector. This characteristic is opposed to, for instance the Low Electrification pathway, that leaves a higher amount of natural gas in Buildings, resulting in higher levels of emissions reductions in other parts of the economy.

Table 2 describes the top-line narrative for each scenario.

Table 2. Key narrative by decarbonization pathway.

Decarbonization pathway	Summary narrative	Key space heating technologies deployed[1]						
		Air Source Heat Pump	Ground Source Heat Pump	Hybrid Heat Pump	Networked Geothermal	Standard Gas Furnace	High Efficiency Gas Furnace	Gas Heat Pumps
High Electrification *Inspired by Roadmap "All Options" Scenario*	Building sector electrifies >90% of buildings, primarily through the adoption of Air Source Heat Pumps.	●						
Low Electrification *Inspired by Roadmap "Pipeline Gas" Scenario*	Building sector electrifies 65% of buildings through the adoption of ASHPs; gas customer count declines by 40% compared to today.	●				●		
Interim 2030 CECP *Inspired by 2020 version of Interim 2030 CECP*	Building sector electrifies in an accelerated pace following goals outlined in the Interim 2030 CECP.	●						
100% Gas Decommissioning *Stakeholder proposed*	Building & Industrial sectors fully electrify by 2050. +/- 25% of the building sector converts to networked geothermal systems.	●	●		●			
Targeted Electrification *Stakeholder & LDC proposed*	>90% of buildings are electrified through a combination of technologies. LDC customers converting to ASHPs do so in a "targeted" approach.	●	●	●				
Networked Geothermal *Stakeholder & LDC proposed*	LDCs evolve their business model and convert +/- 25% of the building sector to networked geothermal systems. Remaining gas customers use renewable gas as their main source of heating by 2050.	●	●		●	●		
Hybrid Electrification *Stakeholder & LDC proposed*	>90% of buildings electrify through ASHPs paired with renewable gas back-up ("hybrid heat pumps") that supply heating in cold hours of the year.			●				
Efficient Gas Equipment *Stakeholder & LDC proposed*	Building sector largely adopts high efficiency gas appliances, supplied by a combination of renewable gases by 2050. The industrial sector converts to dedicated hydrogen pipelines.	●					●	●

To provide a comparison of implications of pathways for the Buildings sector specifically, most pathways keep the decarbonization strategies applied in the transportation and industrial sectors relatively constant. An exception is made for pathways that do not reach 100% decarbonization in the Buildings sector by 2050, which require higher levels of decarbonization in other sectors of the economy, and pathways that fully decommission the gas system by 2050, which require more aggressive levels of electrification in the industrial sector. A full overview of scenario parameters is provided in Appendix 1. Table 3 provides a high-level summary of key parameters by scenario by sector.

Table 3. High level summary of key scenario parameters. More detail on these parameters is provided in Appendix 1.

Scenario	Building Electrification	Industrial Electrification	Transportation Electrification	Networked Geothermal	Building Shell Retrofits	Renewable gas Supply (% of Total Pipeline Gas Throughput)
High Electrification	High	Medium	High	None	High	~5% by 2030, 35% by 2050
Low Electrification	Medium	Medium	High	None	High	~10% by 2030, 70% by 2050
Interim 2030 CECP	High	Medium	High	None	High	~5% by 2030, 35% by 2050
Hybrid Electrification	High	Medium	High	None	Low	~10% by 2030, 75% by 2050
Networked Geothermal	Medium	Medium	High	High (+/- 25% of building by 2050)	High	~10% by 2030, 80% by 2050
Targeted & Optimized Electrification	High	Medium	High	None	High	~10% by 2030, 75% by 2050
Efficient Gas Equipment	Low	Low (converts to 100% hydrogen)	High	None	High	~15% by 2030, 100% by 2050
100% Gas Decommissioning	High	High	High	High (+/- 25% of buildings by 2050)	High	0% by 2030, 0% by 2050

Modeling Framework

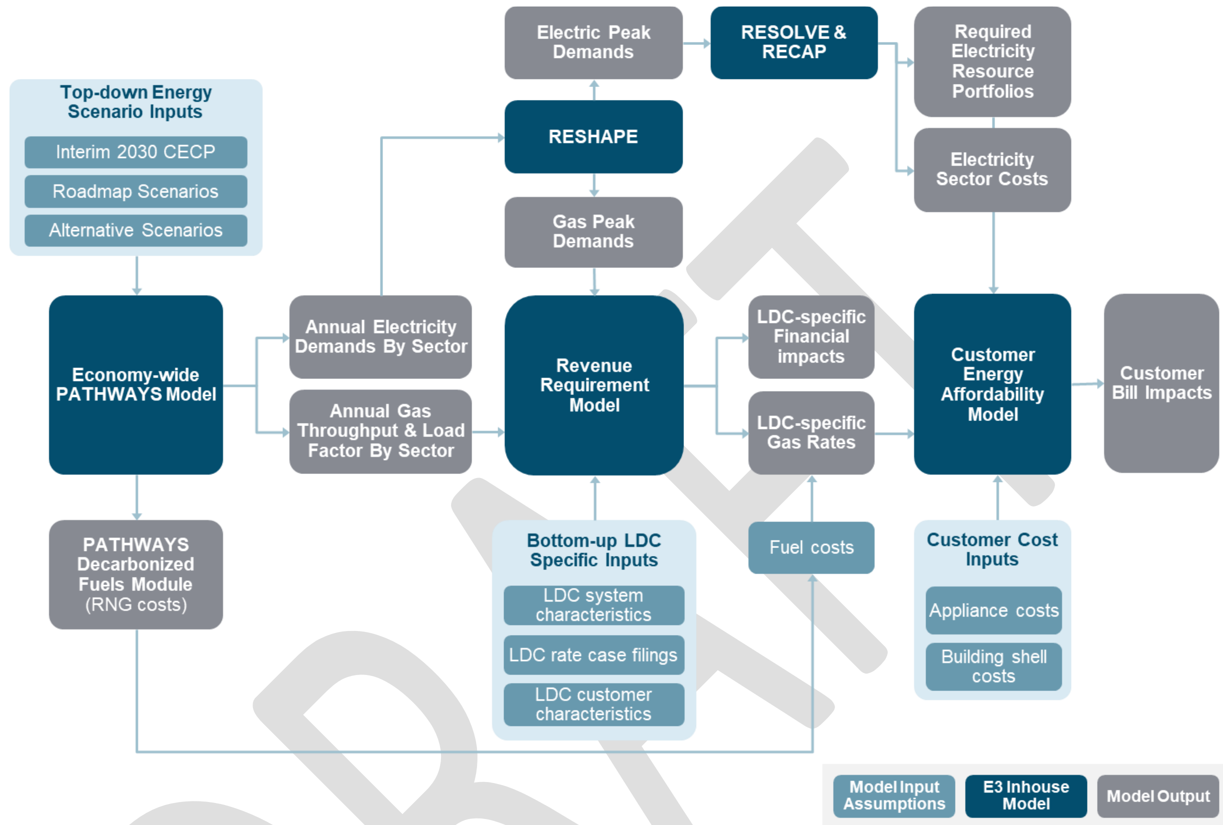
The Consultants used a combination of analytical approaches to identify and assess the decarbonization pathways and their implications for LDCs and LDC customers. Figure 8 provides a summary of the modeling approach, outlining the relationship between key models used to develop and assess pathways and key metrics:

- **Economy-wide PATHWAYS model:** E3's economy-wide model used to assess decarbonization scenarios. This model is similar to the energyPATHWAYS model used to develop the 2050 Roadmap scenarios. It includes a decarbonized fuels module that determines the supply and cost of decarbonized gases.
- **RESHAPE:** E3's model that assesses the impacts of building electrification on annual and hourly electric and gas loads. The model incorporates 40 years of historical weather data.
- **RESOLVE:** E3's electric sector capacity expansion and operations optimization model. RESOLVE is similar to the RIO model used for the Roadmap.
- **RECAP:** E3's electric sector resource adequacy model that is used to benchmark capacity requirements, capacity contributions of generation resources and to evaluate whether portfolios modeled in RESOLVE meet a 1-day-in-10-year loss of load expectation standard.
- **Revenue Requirement Model:** Long-term (through 2050) revenue requirement framework for gas decarbonization analyses. This model assesses the relationships between changing gas supply costs, throughput, load shapes, investment, cost allocation and more on LDC revenue requirements and rates.

- **Customer Energy Affordability Model:** This model calculates energy bills (gas and electric), equipment retrofit costs, and lifecycle economics of decarbonization options.

A detailed description of each of these models is provided in Appendix 1.

Figure 8. Flowchart detailing analysis methodology used in this study.



Alignment with Massachusetts 2050 Roadmap & Key Modeling Differences

At the start of the study process, the Consultants analyzed the Roadmap and Interim 2030 CECP including all underlying assumptions, data and models.[36] The purpose of this analysis was to evaluate how the modeling approaches and key assumptions used in the Roadmap affect the key conclusions of those documents particularly as they relate to the LDCs, and how those assumptions and conclusions inform the examination of alternative pathways.

Where possible, E3 relied on assumptions similar to the assumptions used in the Roadmap to allow for comparison across pathways. However, scenario results cannot be compared directly to the Roadmap due to a set of key differences in modeling approaches. Those differences include:

- **Weather year:** The Roadmap used 2012 weather as the basis for its electric sector modeling, including renewable profiles and load impacts. E3 models electric peak demand impacts and reliability using 40 years of historical weather data in the RECAP model. Within those 40 years, E3

[36] The analyses underlying the 2050 Roadmap and Interim 2030 CECP were developed through a collaboration of the Cadmus Group, Evolved Energy Research (EER), ARUP and the Vermont Energy Investment Corporation (VEIC). The core analysis platforms used by the State's Consultants are the economy-wide energyPATHWAYS model and the RIO electricity system model, both maintained by EER. These models are similar to the economy-wide PATHWAYS model and electricity sector RESOLVE model used by E3.

determined that 2012 was a warm year, both in terms of heating degree days and winter minimum temperature. Given the colder temperatures modeled by E3, we have found higher peak impacts and capacity requirements in electrification scenarios than were identified in the Roadmap.

- **Electric reliability modeling:** E3 utilized a planning reserve margin (PRM) to estimate the total firm capacity required and effective load carrying capability (ELCC) of renewable resources, both derived from the RECAP loss of load probability model. The ELCCs used in this analysis are consistent with E3's prior work modeling high electrification loads in New England.[37] This approach generally results in higher firm capacity requirements to ensure reliability over a wide range of weather and resource availability conditions than were considered in the Roadmap.
- **Gas Revenue Requirements:** The Roadmap includes a high-level representation of a statewide gas revenue requirement, assuming a maximum of 2%/yr in pipeline retirements from electrification. E3's Revenue Requirement modeling enables a detailed treatment of infrastructure retirements and reinvestments per LDC, including the effects of GSEP and potential opportunities for cost avoidance.
- **Commercial space heating service demands:** E3 benchmarked commercial heating demands in Massachusetts to monthly gas sales data from US EIA and found that, based on the seasonality of those sales, a higher share of commercial gas consumption should be attributed to space-heating than was assumed in the Roadmap.

Overview of Key Uncertainties and Sensitivities

The decarbonization pathways presented in this report are not meant as forecasts, and many uncertainties exist when modeling a period out 30 years. Not all uncertainties can be fully captured quantitatively through modeling. The assumptions that were subject to sensitivity analysis in this Report are identified in Table 4. For each assumption, E3 assessed an "optimistic" versus a "conservative" view, drawing from the literature to define those bounds.

[37] E3 and EFI, "Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future," November 2020, available: https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf

Table 4. Key uncertanties captured through sensitivity analysis.

Key uncertainty captured through sensitivity analysis	Optimistic view	Conservative view
Costs of cold climate Air Source Heat Pumps	Heat pumps carry low incremental costs relative to the technologies they replace in most applications.	Electrification has high incremental costs, requiring more substantial building modifications, including electrical work and modifications to ducts or radiators.
Performance of cold climate Air Source Heat Pumps	Technical performance of installed climate heat pumps continue to improve as markets scale.	Performance improvement of installed cold climate heat pumps is relatively modest over time.
Electric sector distribution upgrades	Costs to upgrade the electric distribution network are similar to utilities' historical marginal cost of service.	Large-scale electrification requires distribution system upgrades that are substantially higher than utilities' marginal cost of service.
Installation of Networked Geothermal Systems	Networked geothermal systems can be installed at costs similar to existing geothermal systems.	Large-scale implementation of networked geothermal systems in dense residential areas requires significant additional costs related to engineering & rights of way
Costs & availability of renewable fuels	Market transformation of gasification or other advanced biofuel production techniques occurs. Biofuels feedstocks are available to produce renewable gases. Electrolytic fuels (hydrogen, SNG) come down in cost as markets scale, market and deployment challenges are overcome.	Biomethane is limited by competing demands for biomass and sustainability concerns. Costs of hydrogen and SNG show slow declines as a result of slower technology learning rates or infrastructure deployment for electrolytic fuels. Includes the risk that renewable fuels may take longer to develop at a scale necessary to achieve climate goals.
Opportunities for gas system cost avoidance	(Targeted) electrification leads to avoided investments in gas system infrastructure. Customer departures result in lower O&M costs.	Gas system costs cannot be avoided as mains are not hydraulically separable. O&M costs do not decline with customer departures.

3. The Role of Gas in the Massachusetts Energy System & Key Characteristics of the LDCs

Prior to a detailed review of the various scenarios in Chapter 4, an overview of the role of natural gas in Massachusetts, as well as a discussion of various LDC characteristics and attributes, provides necessary background and context.[38] Specifically, this section of the Report, as well as the detailed analysis in Appendix 3, provides:

- An overview of the significance of winter weather in the Massachusetts energy market;
- A review of the key characteristics of the LDCs and potential implications for decarbonization strategies;
- Observations regarding key distinguishing metrics for the LDCs, which are incorporated into the analyses discussed in Chapter 4.

Massachusetts Energy Market Context

As illustrated by Table 5, New England is one of the coldest regions in the U.S. with 5,822 heating degree days ("HDD") in 2020, which is over 35% higher than the U.S. average.[39] In addition to the number of HDD, the critical importance of winter weather conditions in New England, in general, and Massachusetts, in particular, and the associated implications for energy demand and utility planning can be illustrated by assessing the relative contribution of winter weather (as represented by HDD) to the annual weather conditions (as represented by the combined HDD and cooling degree days ("CDD")). Specifically, New England and Massachusetts have a much higher concentration of HDD relative to the combined HDD and CDD. As shown by Table 5 below, HDD for the New England region represents 90% of the combined HDD and CDD compared to the U.S. average of 75%. For the Massachusetts LDCs, the proportion of HDD relative to combined HDD and CDD ranges from approximately 87% to 95% (as provided in Appendix 3).

[38] The relevance of the unique circumstances of each LDC was reiterated by the Department in its Vote and Order Opening Investigation in D.P.U. 20-80 dated October 29, 2020, in which the Department stated: "*Each LDC is distinct and has different capabilities and limitations within its own service territory.*"

[39] As defined by the U.S. Energy Information Administration ("EIA"), HDD and CDD "are measures of how cold or warm [respectively] a location is. A degree day compares the mean (the average of the high and low) outdoor temperatures recorded for a location to a standard temperature, usually 65° Fahrenheit (F) in the United States. The more extreme the outside temperature, the higher the number of degree days. A high number of degree days generally results in higher levels of energy use for space heating or cooling."

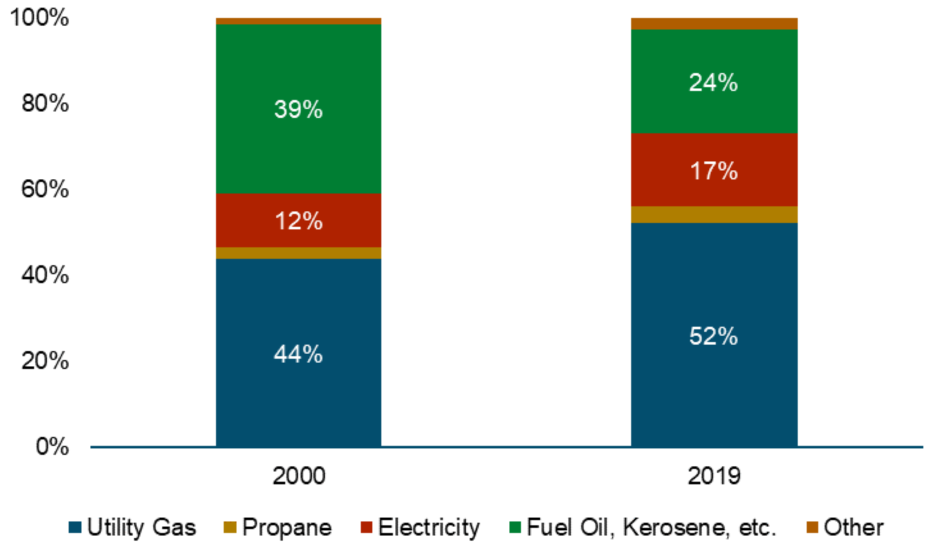
Table 5. HDD relative to total degree days by U.S. region.

Region	Annual HDD	Annual CDD	HDD as % of Total Degree Days (HDD + CDD)
East North Central	5,861	830	88%
East South Central	3,069	1,634	65%
Middle Atlantic	5,224	842	86%
Mountain	4,773	1,679	74%
New England	**5,822**	**643**	**90%**
Pacific	3,208	1,073	75%
South Atlantic	2,252	2,345	49%
West North Central	6,316	965	87%
West South Central	1,822	2,722	40%
U.S. Average	**4,261**	**1,415**	**75%**

Given the critical importance of winter weather conditions in Massachusetts, natural gas and fuel oil play significant roles as the primary sources for home heating needs. Across the Commonwealth, approximately 52% of homes today are heated by natural gas, 24% by fuel oil and 17% by electricity. Stated differently, to meet winter space heating requirements for residential customers, natural gas and fuel oil, combined, have a market share of almost 80% in Massachusetts.

The combined natural gas and fuel oil market share for home heating in 2000 was 83%, compared to 76% today, caused by an increased share of electric heating. In addition, the relative contributions of natural gas and oil have changed significantly over time. The growth in the proportion of homes heated by natural gas in Massachusetts has been consistent at a compound annual growth rate ("CAGR") of approximately 1.0% over the past 20 years, driven largely by customers converting from an alternative fuel to natural gas. As illustrated in Figure 9 below, the market share for natural gas has increased by approximately 20% from 2000 to 2019 (from 44% to 52%); over that same time period, the fuel oil market share has decreased by 38% (from 39% to 24%).

Figure 9. Home heating by fuel type in Massachusetts.



Lastly, the significance of winter weather to the Massachusetts energy market can be observed in a review of retail energy prices. Specifically, average retail energy rates for both electricity and natural gas in Massachusetts (i) are high relative to the U.S. average; and (ii) gas rates typically peak during the winter. The pace of change, and the absolute level and spread between natural gas rates and electric rates are all important considerations when evaluating the relative customer costs and bill impacts of strategies to decarbonize buildings, as discussed in Chapter 5.

Key Characteristics of the Massachusetts Gas LDCs

The Consultants researched relevant LDC characteristics and established a framework to analyze these characteristics across the Massachusetts LDCs. To organize a discussion of the various LDC characteristics and attributes, the Consultants developed four categories of LDC characteristics: service area, demographics, LDC statistics, and LDC system. The tables below describe each of the metrics used to evaluate LDC characteristics, summarizes the key findings from that research and then describes the implications of these findings for the LDCs in support of achieving the Commonwealth's climate goals. A detailed overview of these characteristics is provided in Appendix 3.

LDC Service Area

The LDC service area characteristics analyzed by the Consultants include home heating fuel, gas customer data, and gas and electric utilities service areas. A summary of these characteristics and the key implications for decarbonization planning are described below.

Table 6. Summary of LDC service area characteristics.

Metric	Summary characteristics by LDC	Implication
Home heating fuel, fuels used by the residential sector for space heating by LDC, by total housing units, owner-occupied units, and tenant-occupied units	• Over 60% of households in National Grid (the former Colonial Gas) and Liberty service territories use natural gas as their main source of home heating. • National Grid (Boston Gas) and Eversource service territories have a market share above 50% for natural gas home heating. • The Berkshire and Unitil service territories have the lowest natural gas market share for residential space heating and, conversely, the highest market share for fuel oil.	Building sector decarbonization and space heating electrification programs will need to address the significant market share of natural gas and fuel oil, as well as consumer preferences.
Gas customers, total residential and non-residential customers by LDC	• National Grid and Eversource together represent 91% of the approximately 1.7 million natural gas customers in Massachusetts. • Berkshire, Liberty, and Unitil together account for 7%, and the remaining 2% are served by municipal gas utilities.	National Grid and Eversource are the largest LDCs in terms of impact on the Commonwealth's climate goals.
Gas and electric utilities, service area of each LDC and the corresponding electricity service provider	• The majority of natural gas customers in Massachusetts receive electricity from a utility that is different than the utility providing natural gas service, with the exception of Unitil, which has a 87% overlap between its gas and electric customers.	Inter-fuel planning (i.e., across electricity and natural gas) will most likely require the participation of multiple utilities, thus increasing the complexity and time required for planning (including regulatory submissions and benefit/cost sharing).

With respect to natural gas service providers, in Massachusetts there are three combination (gas and electric) utilities (i.e., Eversource, National Grid, and Unitil) and two natural gas-only utilities (i.e., Berkshire and Liberty). The overlap in service territories for gas and electric customers is illustrated in Table 7. National Grid provides electricity service to 39% of its natural gas customers, while the remaining 61% of National Grid's natural gas customers receive electricity service from another utility. Similarly, Eversource provides electricity to 48% of its natural gas customers, while the other 52% of Eversource's natural gas customers receive electricity from another utility. Unitil, however, provides electricity to approximately 87% of its natural gas customers.

Table 7. Overlap of gas and electric service providers.

Gas Provider: 2020 Gas Customers	Electricity Provider: National Grid	Eversource	Unitil	Municipal
National Grid	378,500 39%	469,800 49%	800 0%	110,400 12%
Eversource	272,500 42%	311,900 48%	NA	61,400 10%
Unitil	2,100 13%	NA	14,100 87%	NA
Liberty	51,000 85%	4,400 7%	NA	4,400 7%
Berkshire	12,300 30%	28,400 70%	NA	NA

Percentages may not add to 100% due to rounding

Demographics

The Demographics characteristics analyzed by the Consultants include population density and growth, age and type of housing, income distribution and environmental justice metrics. A summary of these characteristics and the key implications for decarbonization planning are described below.

Table 8. Summary demographics characteristics by LDC.

Metric	Summary characteristics by LDC	Implication
Population density and growth, including historical growth and density metrics	• National Grid and Eversource have the highest population density of the LDCs, as well as the highest forecast of population growth • Liberty and Unitil may see declining population growth rates through 2040	LDC service areas with higher population density may be harder to cost-effectively electrify given the challenges associated with neighborhood-scale/group adoption dynamics and siting electric network infrastructure. An LDC with a higher forecasted growth in population may be able to implement decarbonization programs that not only target existing customers, but also new construction. LDCs with more limited population growth will need to develop decarbonization programs that focus primarily on existing customers.

Age and type of housing, including vintage or age of the housing stock, owner- or tenant-occupied units, number of units per structure, and number of rooms per unit	• Single-unit housing is the most common type of housing across the state. One-third of the housing structures were built prior to 1940 statewide. • Liberty, National Grid (Boston Gas) and Eversource (NSTAR) have the highest proportion of multi-unit structures. • National Grid (the former Colonial Gas) has a relatively newer housing stock compared to the rest of the state. • Among other LDCs, over 70% of the housing stock was built prior to 1980. • 56% of housing units is owner-occupied, and 34% is tenant-occupied. National Grid (Boston Gas) and Liberty have the lowest percentage of owner-occupied and the highest percentage of tenant-occupied units in their service territories.	The diversity in housing stock will inform decarbonization programs offered by each LDC, as well as the implementation approaches for those programs. Multi-unit and tenant-occupied units can be more difficult to electrify than single-family, owner-occupied homes. Older vintage homes may be more costly to retrofit, requiring more substantive upgrades to building shells, ductwork, radiators or electrical wiring.
Income distribution	• Consistently across LDCs, approximately 15% to 20% of households have an annual income lower than $25,000. • Liberty and Berkshire have the highest proportion of low-income customers. • National Grid and Eversource have the highest proportion (approximately 25%) of households with an annual income of $150,000 or higher compared to only 12% for the other three LDCs.	Income distribution may indicate the need for LDCs to develop low-income decarbonization programs that are supported by higher income customers. LDCs with a larger proportion of higher income customers may have more “first movers” or “early adopters” with respect to new or innovative space heating technologies.
Environmental Justice (“EJ”) including income, minority population, English isolation, and certain combinations of these metrics	• National Grid and Eversource have the highest population in designated EJ groups relative to state-wide EJ population; the other three LDCs represent a smaller EJ population relative to state-wide EJ population. • Unitil, Berkshire, and National Grid (Boston Gas) have the highest concentration of population in designated EJ groups relative to their total populations. • National Grid (Boston Gas) has the highest share of population meeting the English Isolation criteria for EJ groups.	Each LDC will likely need to develop approaches to supporting and addressing decarbonization strategies within EJ populations that reflect the metrics of that LDC. For example, National Grid (Boston Gas) may need more focus on communication approaches in languages other than English, given its level of customers that meet the English Isolation metric.

As shown by Table 9, every LDC has EJ populations that will need to be considered with respect to decarbonization programs and polices.

Table 9. Environmental justice criteria by LDC.

EJ Criteria	Berkshire	ES-EGMA	ES-NSTAR	Liberty	NG-Boston Gas	NG-Colonial Gas	Unitil	MA Total
EJ Population*	96,000	607,000	567,000	85,000	1,431,000	179,000	46,000	3.1M
% of Service Area Pop.	53%	43%	46%	45%	52%	31%	56%	45%
* The EJ population does not reflect the number of people that meet an EJ metric, but rather the total population within the block groups that meets the EJ metrics. More detail on this metric is provided in Appendix 3.								

LDC Gas Statistics

The LDC gas statistics analyzed by the Consultants include gas revenues and volumes, annual and peak day sendout, planning standards and projected gas demand, and the gas supply resource portfolio. A summary of these characteristics and the key implications for decarbonization planning are described below.

Table 10. Summary LDC gas statistics.

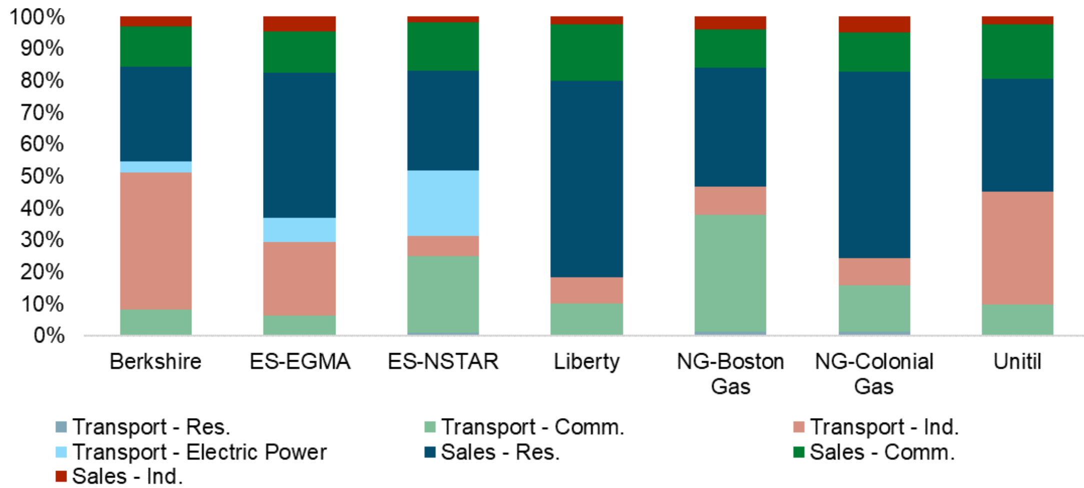
Metric	Summary characteristics by LDC	Implication
Gas revenues and volumes, by customer segment and on a per customer basis, total volume and breakdown by customer segment and on a per customer basis, and sales and transportation[40] volume by customer segment for each LDC	• Across the LDCs, the residential segment contributes approximately 60% to 75% of revenues. From a volume perspective, the contribution from the residential segment is more varied. • Liberty and National Grid (the former Colonial Gas) have the highest proportion of residential sales. • Berkshire and Unitil have the highest proportion of industrial sales. • National Grid (Boston Gas) has the highest proportion of commercial sales.	Utilities with a higher share of harder-to-electrify customer segments, particularly industrial and some large commercial customers, may need to emphasize hybrid and renewable gas strategies more than LDCs with a larger share of residential customers. LDCs with a significant level of transportation volume (i.e. gas delivery only) may need to implement programs that encourage, or set metrics for, renewable gas deliveries by third-party marketers.
Annual and peak day sendout. A review of actual peak day and peak year volumes by LDC	• All LDCs have recently (i.e., either 2018 or 2019) experienced their highest daily sendout of gas. The combined LDC actual sendout was approximately 2.5 Tbtu.	Demand for gas services has increased in Massachusetts in the past years. Expansion of gas service and system capacity may lead to underutilization of the gas system if electrification becomes a dominant strategy.

[40] Transportation customers are responsible for their own natural gas commodity procurement.

Planning standards & projected gas demands. A review of the weather conditions and planning standards, forecasted design day and growth rates	• The LDCs plan for a combined Design Day volume of 2.8 Tbtu, of which National Grid and Eversource together represent 94% of the total. National Grid and Eversource have projected a design day annual growth factor of over 1.5%. • To meet Design Day load, each LDC has a unique gas supply portfolio (e.g., delivering pipelines) that includes some level of on-system LNG and/or propane facilities.	Meeting energy demands, particularly during design day/cold temperature periods is critical to energy system reliability and resilience. Under high electrification scenarios, these energy demands would need to be served almost entirely by the electric system. Under hybrid and lower electrification scenarios, a portion of winter peak energy demands would continue to be served by gas infrastructure, as well as by the electric grid.
Supply resource portfolio. An overview of each LDC's resource portfolio and relative contributions from pipeline, storage, and on-system resources	• The LDCs have 23 on-system peaking LNG and propane facilities, of which 75% are located in designated EJ communities, with over 0.9 Tbtu/day of design day capacity and just under 11 Tbtu of storage.	The LDC resource portfolios are designed to meet various winter weather conditions with a high focus on providing gas supply during an extreme cold day event. Decarbonization pathways with a significant level of space heating electrification will need to consider what role, if any, these on-system peaking facilities and upstream supply resources may play in maintaining safe, reliable and resilient energy service to customers.

As illustrated by Figure 10, each LDC has a unique combination of sales and transportation volume by customer segment, which will likey require unique and customized approaches to decarbonization strategies. By way of example, an LDC with a significant level of transportation volume may need to implement programs that encourage, or set metrics for, renewable gas deliveries by third-party marketers.

Figure 10. Annual LDC natural gas volumes by segment and type - 2020.



LDC System

The LDC gas statistics analyzed by the Consultants include an overview of utility gas plant (the assets owned by LDCs), system density and mains and services. A summary of these characteristics and the key implications for decarbonization planning are described below.

Table 11. Summary LDC system characteristics.

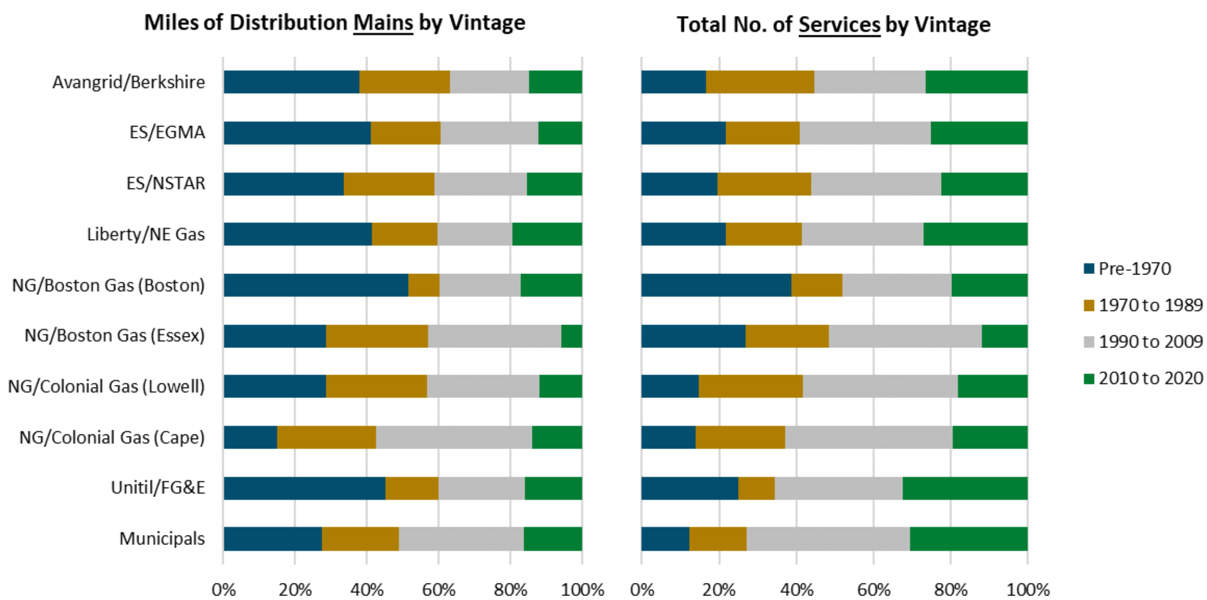
Metric	Summary characteristics by LDC	Implication
Utility gas plant, mains, services, meters, and total plant by LDC	• Across the LDCs, transmission and distribution ("T&D") plant represents the largest share of the utility gas plant balance, ranging from 66% (Berkshire) to 95% (Unitil). • Within T&D plant, mains represent a larger share of utility gas plant than services and meters; however, the proportion varies greatly across the LDCs, with mains representing roughly 50% of utility gas plant for National Grid, Eversource, and Unitil.	LDCs are capital intensive physical infrastructure entities that have significant underground plant (i.e., mains and services) used to deliver natural gas to customers. Should the utilization of LDC T&D infrastructure decline as a result of electrification programs, the remaining natural gas customers, absent any regulatory policy changes, will see higher volumetric rates and customer bill impacts associated with the cost recovery of the LDCs' T&D investments
System density, services per mile of main	• National Grid (Boston Gas) has the highest system density. • Berkshire and Unitil have the lowest system density, although LDCs with a low density value may have cities, towns, or neighborhoods within their service territory with much higher density levels.	Areas that serve a greater diversity of loads, including medium density residential and commercial areas, may provide more beneficial opportunities for

		the deployment of networked geothermal systems.[41] LDC service areas with higher density may be harder to cost-effectively electrify given the challenges associated with neighborhood-scale/group adoption dynamics and siting electric network infrastructure.
Mains and services, LDCs' distribution mains and services by vintage and material	• Statewide, unprotected steel and cast iron represent approximately 22% of distribution mains and 13% of services, and together are considered "leak-prone" pipeline materials. • National Grid (Boston Gas) has the highest proportion of pre-1970 mains and services. • Unitil has the highest proportion of mains and services installed since 1990.	In general, newer distribution mains will be less leak-prone than older pipe, and will have a longer remaining economic lifetime. Decarbonization programs that target customer-specific electrification will need to consider impacts to both distribution mains (i.e., overall system integration and reliability) and services (i.e., customer-specific connection to a main).

On a state-wide basis, nearly 40% of distribution mains and over 25% of services were installed prior to 1970, and approximately 40% of mains and 55% of services were installed since 1990 (Figure 11).

[41] A Study on networked geothermal systems by HEET indicates that both very low density and ultra-high density areas are not likely to be suitable for such systems. The study indicates that vertical group-coupled Ground Source Heat Pump systems in low to medium density residential and mixed-use commercial districts may provide the best performance to meet buildings' heating and cooling loads. https://heet.org//wp-content/uploads/2019/10/HEET-BH-GeoMicroDistrict-Final-Report.pdf

Figure 11. Distribution of services and mains by vintage and LDC.



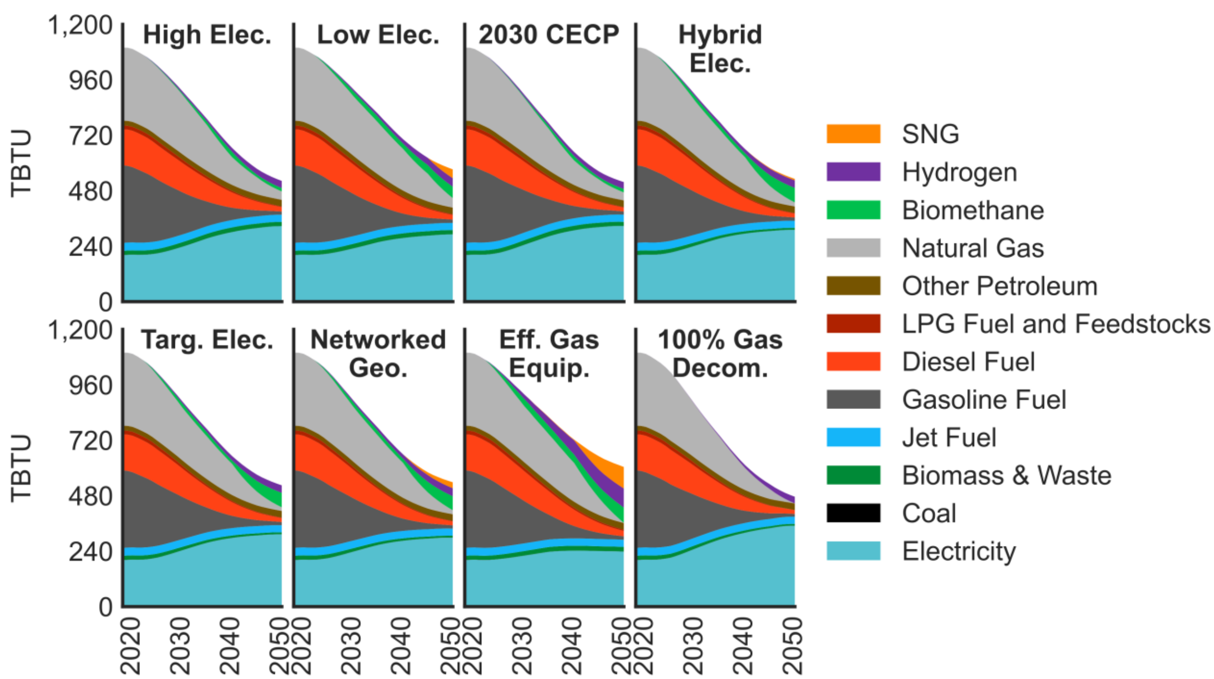
4. Pathways to Carbon Neutrality in Massachusetts

This Chapter details the results of E3's decarbonization modeling and impacts on the gas and electric system. Further implications of these pathways are discussed in Chapter 5.

Economy-Wide Energy System & Emissions

The pathways analysis shows that although achieving net zero emissions by 2050 in the Commonwealth is possible, it requires a transformation of the Massachusetts energy system, altering the way residents and businesses produce, supply, and use energy throughout all sectors of the economy. While Massachusetts' current energy system largely relies on petroleum and natural gas, the 2050 energy systems in the decarbonization pathways analyzed are dominated by electricity and renewable fuels, as shown on Figure 12. There is 45-57% reduction in final energy demand by 2050 compared to today across all decarbonization scenarios. This is primarily due to electrification (in the transportation, industrial and building sectors) and building shell improvements in the long run and partly driven by appliance efficiency measures in the short term.

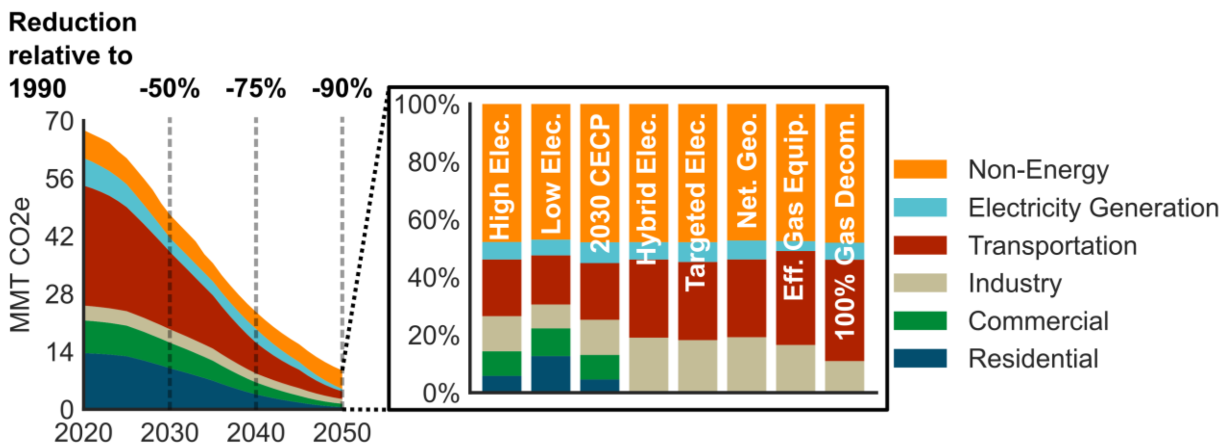
Figure 12. Final energy demand by fuel with optimistic assumptions for biomethane availability and cost (TBTU). Note that pipeline gas demands are split into SNG, hydrogen, biomethane, and natural gas. Dedicated hydrogen is bundled in the hydrogen category.



Most notable in final energy demand across scenarios is the increased reliance on electricity and the reduction in fossil fuels over time. The increase in electricity demand across all pathways is the result of transportation electrification, industrial electrification, and building electrification substantially reducing the use of both petroleum fuels and natural gas. The 100% Gas Decommissioning scenario fully eliminates the use of gaseous fuels in the distribution system and all scenarios transition, to varying degrees, to some use of renewable gases over time:

- The 100% Gas Decommissioning scenario fully eliminates the use of gas on the distribution system. Electric loads increase the most for this pathway, mostly driven by high levels of electrification in the industrial sector. Note that not all industrial facilities are assumed to electrify. Those industrial sectors that are hard to electrify require transitioning to using on-site hydrogen or another form of zero-carbon fuel.
- The Efficient Gas Equipment scenario has the largest volumes of gas flowing through the distribution system. In addition, relatively high volumes of hydrogen are used as dedicated infrastructure that can deliver 100% hydrogen to segments of the industrial sector is developed.
- Both the High Electrification and Interim 2030 CECP pathways result in a large increase in electricity demand and a steep decline in pipeline gas throughput, mostly leaving natural gas in the industrial sector towards 2050.

Figure 13. Economy-wide GHG Emissions over time and the sectoral composition of emissions in 2050.



While an overview this Report's approach to GHG emissions accounting is provided in Appendix 1, key elements of remaining emissions are discussed here. All scenarios comply with the Commonwealth's climate legislation, reaching gross emission levels of 50% by 2030, 75% by 2040, and 90% by 2050 compared to 1990 levels (Figure 13) using the Commonwealth's emissions accounting methodology. This means that, similar to the Roadmap, gross economy-wide emissions reach 9.5 MMT CO_2e by 2050. All pathways, similar to the Roadmap, have approximately 4.5 MMT CO_2e of non-energy emissions remaining in 2050. Most of these emissions are accounted for by the Waste sector, F-gases, and non-energy emissions from industrial processes. An approximate 14% of non-energy emissions are the result of methane leakage in the gas transmission and distribution system.[42]

Non-energy emissions are largely the same across all scenarios in 2050, and the remaining 5 MMT CO_2e comes from direct combustion emissions arising from buildings, transportation, industry, and electricity generation. Because of the nearly fixed emissions budget for direct emissions, scenarios with higher remaining buildings sector emissions necessarily require lower emissions in transportation and industry. Inversely, those scenarios with lower buildings sector emissions allow for higher emissions in transportation and industry. Most notably, heavy duty transportation and aviation require significant volumes of renewable diesel and jet kerosene to compensate for higher building sector emissions in scenarios like the Low Electrification.

[42] Note that a full description of non-energy emissions, including methane leakage trajectories, is provided in Appendix 1. The Commonwealth's emissions trajectory is based on the IPPC AR4, which uses a 100-year Global Warming Potential (GWP).

As analyzed in the Roadmap's Land Sector Report, the Commonwealth needs to reach a net-zero economy through negative emissions and carbon sequestration in its natural lands and forests to compensate the 9.5 MMT CO_2e of emissions that remain by 2050. Part of that sequestration, approximately 5 MMT CO_2e per year by 2050, is expected to come from sequestration through enhanced forest management. The remaining emissions need to be sequestered by leveraging carbon dioxide removal (CDR) technologies within and outside of the Commonwealth's boundaries.

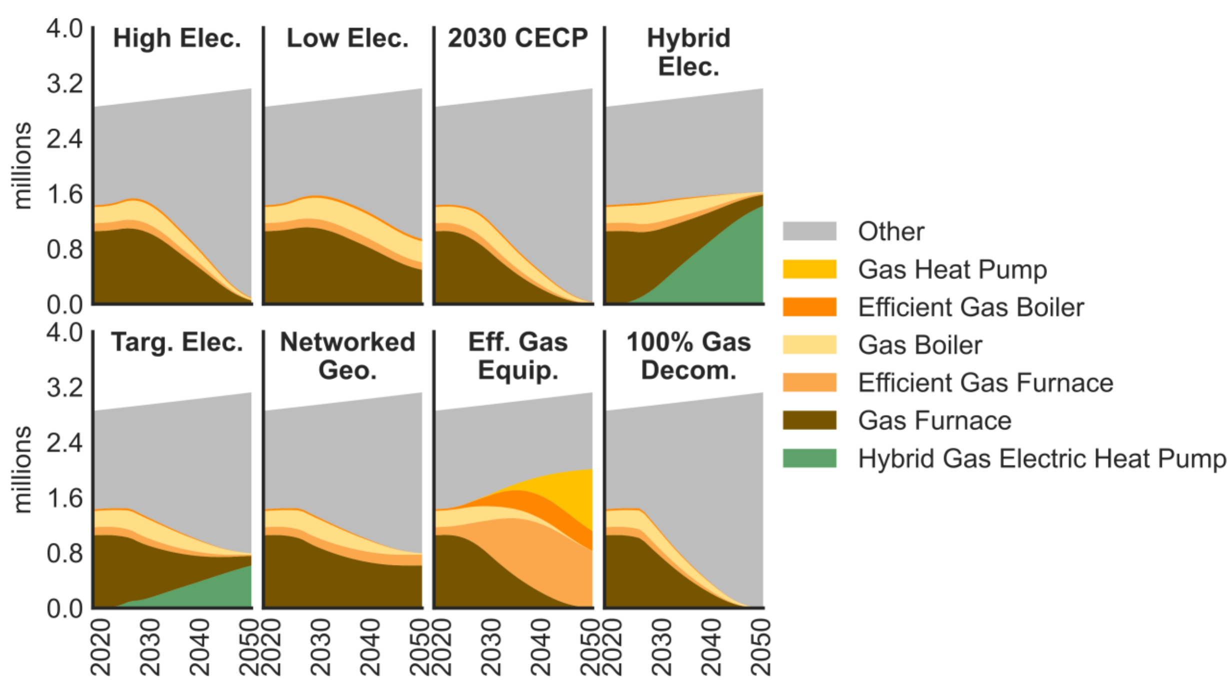
Building Decarbonization: Renewable Fuels, Energy Efficiency, and Building Electrification

Per the scope of this Report, the following section primarily focuses on building sector decarbonization. The decarbonization pathways analyzed show multiple strategies to decarbonize the Buildings sector, varying the levels of renewable fuels, energy efficiency and building electrification, as outlined in detail below.

Renewable Fuels

Although renewable fuels play a role across all pathways, the level of decarbonized fuel use in the Buildings sector is most notable in those pathways that include an ongoing role for gas in buildings. Figure 14 shows residential space heating stocks by pathway, highlighting the level of space heating devices that continue to rely on gas over time. A similar transformation occurs for commercial buildings (see Appendix 1).

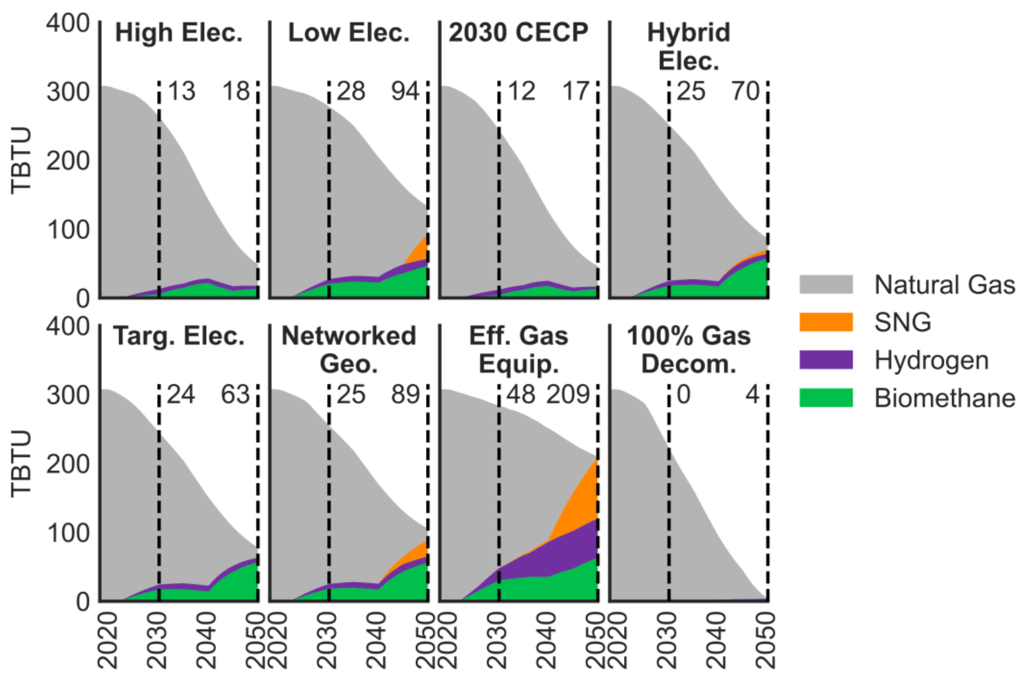
Figure 14. Residential space heating stocks by scenario, emphasis on gas heating.



As seen in the figure, the Efficient Gas Equipment pathway relies most heavily on gas technologies towards 2050, requiring both a transformation of the building stock to more efficient gas appliances and gas heat pumps. Other pathways, such as Hybrid Electrification and Targeted Electrification, shift how gas is used for space heating by using hybrid electrification technologies that consume gas in only the coldest hours of the year. In the Networked Geothermal and the Low Electrification pathways, gas technologies make up 25% and 30% of residential space heating stocks by 2050 respectively, compared to approximately 50% today. A similar transition to that shown for the residential sector takes place in the commercial sector, with greater emphasis on gas heat pumps for the Efficient Gas pathway.

As a result of energy efficiency and the transition away from gas-driven space heating technologies, all pathways result in substantially reduced distribution gas volumes by 2050. In all pathways in which there is continued reliance on gas, including those with hybrid technologies, the pipeline gas supply transforms over time from primarily natural gas to a mixture of natural gas and renewable gases, including biomethane, hydrogen and SNG. Pathways with more gas throughput rely more heavily on hydrogen produced via electrolysis and SNG in later years. Figure 15 provides an overview of the gas supply transformation by scenario. Note that the Efficient Gas Equipment pathway results in higher levels of hydrogen compared to other scenarios as this pathway assumes dedicated hydrogen infrastructure is built to serve industry, whereas other scenarios allow for only a 7% blend of hydrogen by energy content.

Figure 15. Gas throughput and composition over time (TBTU). Chart portrays cases with optimistic renewable gas assumptions. High hydrogen demand in the Efficient Gas scenario is a result of dedicated hydrogen pipelines to commercial buildings and industry.



The composition of renewable fuels by pathway are determined using a supply curve. This supply curve approach, described in more detail in Appendix 1, illustrates that most biomethane resources are available at lower costs than hydrogen and SNG, although this dynamic changes as hydrogen becomes lower cost over time. However, while biomethane resources are lower cost, they are limited in their availability. This is due to three factors that make it likely that the LDCs will be procuring renewable fuels in a highly competitive market. First, there is a limit to the quantity of sustainable biomasses in the United States. Second, it is expected that other jurisdictions pursuing decarbonizing will also demand biofuels. Third, it is expected that some biomass feedstocks can be more cost-effectively converted into other fuels, such as renewable diesel and gasoline, to meet the needs of hard to electrify sectors, such as aviation, freight and industry.

Recognizing the significant amount of uncertainty related to the availability and costs of renewable gases, the Consultants developed two separate views for the purpose of this Study:

- Optimistic view: Biomethane is sourced through both anaerobic digestion and gasification. Lower hydrogen and SNG costs are driven by optimistic electrolyzer cost and electricity fuel price trajectories.
- Conservative view: Biomethane is only sourced from anaerobic digestion. Higher hydrogen and SNG costs are driven by conservative electrolyzer cost and electricity fuel price trajectories.

As described in more detail in Appendix 1, the Consultants assume that Massachusetts will be able to use its "fair share" of sustainable biomass available in the U.S. east of the Mississippi River. This fair share is estimated to be the Commonwealth's population-weighted share of these feedstocks and the geographic extent was chosen to reflect a region where resources could be delivered on the existing interstate gas pipeline system.[43] It is important to note that these views are "bookends" to likely biomass availability in the next thirty years, driven by policy, market, and technical conditions. For example, policy may drive deeper (or shallower) decarbonization targets in other sectors and jurisdictions, decreasing (or increasing) available biomass for biomethane. Alternatively, a national market for decarbonized fuel credits similar to renewable energy credits could emerge, which could increase the "availability" of renewable fuels even if the fuels themselves are not deliverable to the Commonwealth. Finally, different mixtures or levels of feedstocks could be available for relatively low-cost conversion to different renewable fuels.

[43] As pointed out in Appendix 2 (Literature Review), New England has limited access to local renewable gas feedstocks, especially when compared to other regions in the country. For example, in New England there is an estimated 0.63 dry tons of feedstock available per person per year, whereas the average availability of feedstocks for the US as a whole is 2.47 dry tons per person per year. For this reason, New England would likely have to import feedstocks or renewable gases if those fuels played a significant role in meeting future energy needs in the region.

Figure 16. Sankey diagrams showing conversion of organic feedstocks to renewable fuels under conservative and optimistic feedstock availability assumptions. Feedstocks are labeled by the total amount of energy they contribute to all end fuels and the process by which they could be converted to biomethane (AD = anaerobic digestion, G = gasification). Renewable fuels are labeled by the total amount of fuel produced in terms of energy.

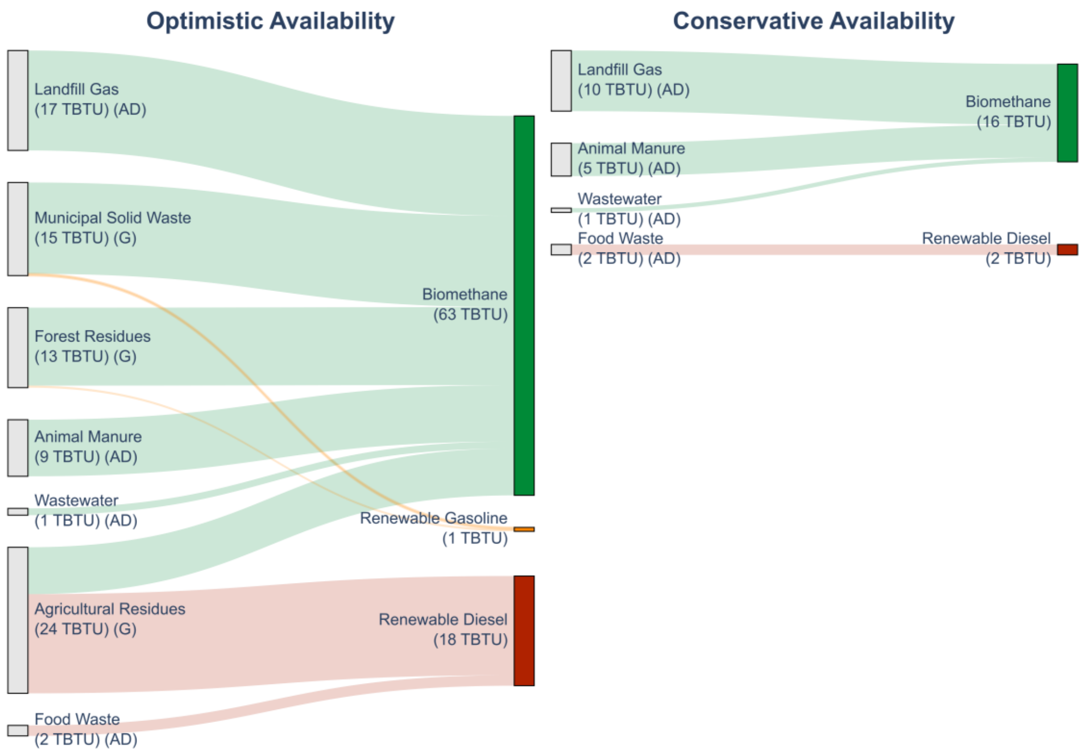


Figure 16 shows Sankey diagrams for the Efficient Gas Equipment scenario under both conservative and optimistic views. Consistent with the Consultant's assumptions, some biomass is converted to other fuels besides biomethane. Specifically, renewable diesel and renewable gasoline represent 23% or 11% of the total amount fuel produced by energy under the optimistic and conservative assumptions. As a result, only 62 or 16 TBTU of biomethane would be available to Massachusetts, respectively. Because 2050 total gas demand is approximately 210 TBTU, the Commonwealth must rely on significant volumes of SNG supplied from out of state. The production of synthetic gases requires green hydrogen production and a carbon neutral source of CO_2 from either biorefineries or direct air capture. Such processes require substantial commercialization efforts as well as significant amounts of dedicated renewable energy capacity to be produced at the scales envisioned in this analysis, as further detailed in Chapter 5.

In this Study, the Consultants have assumed that renewable fuels have a net-zero GHG impact, consistent with the Massachusetts GHG inventory. This contrasts to other states, such as New York, that have adopted a lifecycle approach to accounting GHG impacts of renewable fuels. The Consultants recognize that treating renewable fuels as having net-zero emissions is a simplification of the complex carbon flux associated with these fuels, as is further detailed in Appendix 1. As such, pathways that rely more heavily on renewable fuels bears the risks related to GHG accounting methods changing over time.

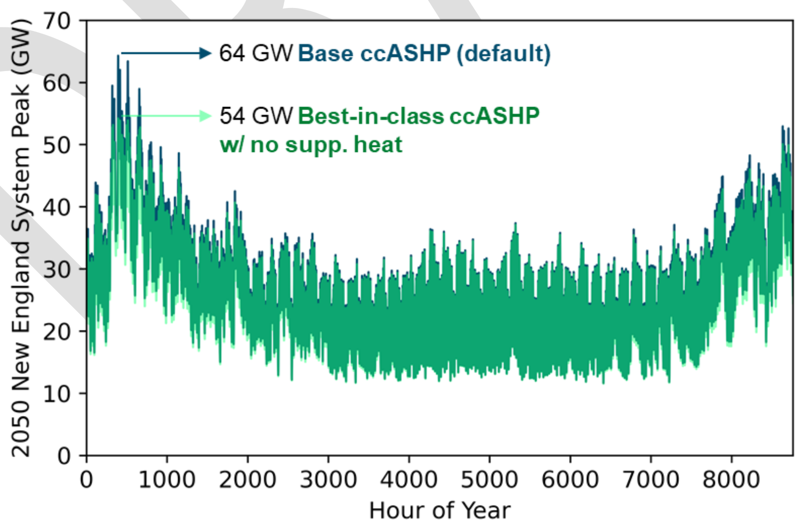
Energy Efficiency

Energy efficiency will play a key role in deeply decarbonizing the Commonwealth's economy. Within this study, efficiency takes on the following forms across the economy:

- Building shell efficiency, which reduces heat lost to the environment and thus fuel demands for space heating;
- Electrification, such as replacing reference gas furnaces with significantly more efficient air source heat pumps (ASHPs);
- In-kind, high efficiency replacements, such as the adoption of more efficient lighting and other electric appliances. This category also includes switching reference gas furnaces to efficient gas furnaces or gas heat pumps;
- Industrial manufacturing efficiency.

As already partially depicted Figure 12, energy efficiency plays an important role across the economy, including in the Buildings sector. Decarbonization pathways show a reduction in final energy demand in the residential and commercial sector between 41-59% compared to today, mainly because of electrification and building shell improvements. Pathways that include a higher level of building electrification, such as 100% Gas Decommissioning and High Electrification, see the largest reduction in final energy demand in buildings, as heat pumps meet heating demands more efficiently than conventional combustion technologies. For example, the coefficient of performance (COP) – a measure of efficiency – for ASHPs and ground source heat pumps (GSHPs) are in the range of 2.4–3.5 and 3.4–4.0 over the study period, compared to 0.9 for standard gas furnaces. This means that electrification significantly reduces the energy required to heat buildings in Massachusetts. The Efficient Gas Equipment pathway relies on in-kind, high efficiency end-use replacements like switching reference gas furnaces and boilers to efficient alternatives like condensing units and gas heat pumps (GHPs). GHPs are assumed to achieve a COP of 1.4 and can significantly reduce fuel demand, though to a lesser extent than electric heat pump technologies.

Figure 17. Simulated New England hourly load profiles for High Electrification scenario in 2050, with default and improved cold-climate air-source heat pump (ccASHP) efficiencies, before load flexibility contributions.[44]



To demonstrate the impact of heat pump efficiency on electric loads, the Consultants developed a sensitivity of the High Electrification pathway in which heat pumps are assumed to be 12% (in the case of

[44] System peaks are determined using the same weather year (median weather year for base High Electrification scenario), before accounting for firm capacity contributions by load flexibility.

GSHPs) to 30% (in the case of ASHPs) more efficient by 2050. That level of performance is consistent with significant technology improvements and a transformation of installation practices relative to today. Figure 17 shows that this assumption predominantly impacts the heating requirements on the coldest days of the year, reducing "peak demand" by 16% compared to the default High Electrification pathway.

Another important set of measures contributing to energy efficiency are building shell improvements. Most homes in the Commonwealth are relatively old (see Chapter 3), so improvements in building shells can lead to substantial reductions in energy needs. High levels of building shell improvements are assumed across the Commonwealth's building stock in nearly all pathways. For example, 50with nearly half a million households retrofitted by 2030 and nearly 1.5 million households by 2050 in the Interim 2030 CECP scenario, the Massachusetts building stock must substantially transform in the next decades to achieve the levels of energy efficiency assumed in these pathways. Although building shell upgrades can be relatively expensive on a customer level[45], those modeled in this study are societally cost-effective for the following reasons:

- For those scenarios relying heavily on electrification, improved building shells help mitigate both the annual load and peak demand impacts of building electrification on the electric sector.
- For those scenarios relying heavily on renewable fuels, building shell measures reduce the volumes of more expensive renewable fuels required.

It is important to note that the benefits of deep building shell improvements on the electric sector and gas supply are less prevalent in the Hybrid Electrification pathway, as both electric peak impacts and expensive fuel costs are mitigated through usage of the gas system as winter backup (Text Box 1). This pathway therefore does not include the same level of building shell improvements as other pathways.

[45] Costs of building shell improvements in the Commonwealth and across the United States as a whole are uncertain, and decarbonization literature shows a broad range of cost and efficiency assumptions. In this Study, building shell upgrades are assumed to cost 6.3 $/square ft.

Text Box 1. Example of costs and benefits associated with building shell improvements.

As an illustrative example, assuming $10,000/shell for single family building efficiency improvements (discounted at 3.6% with a lifetime of 40 years), 1.1 million shell retrofits, and 15% energy savings in residential space heating due to efficiency retrofits (averaged over the entire building stock), we estimate that the annualized costs would be ~$145 million higher than savings for the Hybrid Electrification scenario by 2050:

- Annualized cost: ~$520 million for building shells
- Annualized savings (2050): ~$375 million total (electric generation capacity, electric transmission and distribution, fuel use for electricity generation; fuel use for space heating)

These results will vary depending on assumptions, but will likely not change the sign of cost-effectiveness, given the sizeable difference between costs and savings. In contrast, using a similar comparison, we find that building shell improvements result in net savings for scenarios that rely more heavily on electrification during coldest hours of the year. A key driver for this difference in savings is that electric system peak impacts are much higher in a highly electrified scenario than the Hybrid Electrification scenario, resulting in more opportunities for savings in electric generation capacity and T&D investments. This suggests that a shell measure produces higher electric system value in an electric approach than a hybrid-only approach. Similarly, pathways that rely to a large extent on renewable gases see higher benefits from shell measures than a Hybrid Electrification pathway, as building shell measures result in the avoidance of expensive types of renewable gas (which, in the case of the Efficient Gas scenario, are driven by the costs of SNG in outer years).

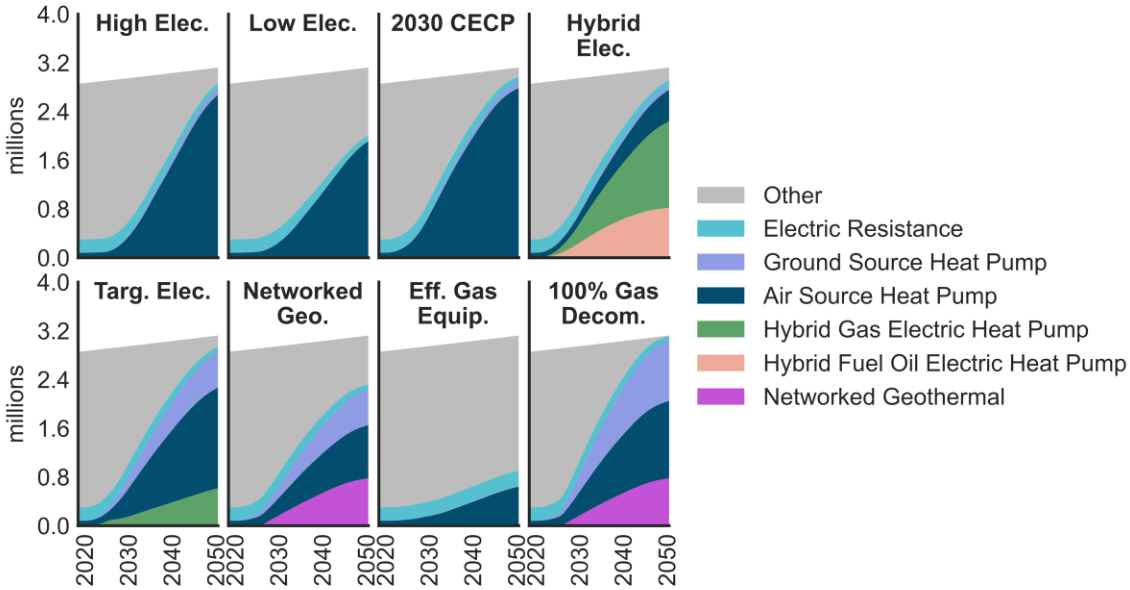
Building Electrification

Figure 18 shows the level of building electrification for residential space heating technologies across pathways. Although electrification occurs across all pathways, the level and composition of building electrification varies substantially:

- The High Electrification, Interim 2030 CECP, Hybrid Electrification and Targeted Electrification pathways have similar adoption levels of electric space heating technologies, using a mix of heat pump technologies. While electrification in the High Electrification and Interim 2030 CECP pathways results mostly on ASHPs in the residential sector by 2050, buildings in the Hybrid Electrification pathway primarily adopt ASHPs with gas backup (hybrid heat pumps). The Targeted Electrification pathway has the most variation in electric space heating technologies, assuming a mix of ASHPs, ground source heat pumps (GSHPs), and hybrid heat pumps.
- Networked geothermal systems play a role in the Networked Geothermal and 100% Decommissioning pathways. In these pathways, approximately 800,000 gas customers are assumed to transition to networked geothermal systems between 2027 and 2050, avoiding infrastructure replacements that are part of the GSEP and other LDC capital programs.

The transition of commercial heating equipment is similar within each pathway to the transition taking place in the residential sector, with differences mainly in the ratio between electric boilers and heat pumps, and the level of networked geothermal systems achieved. An overview of the commercial space heating stock transition is provided in Appendix 1.

Figure 18. Residential space heating stocks by scenario, emphasis on electrification. A full overview of space heating stock conversions is provided in Appendix 1.



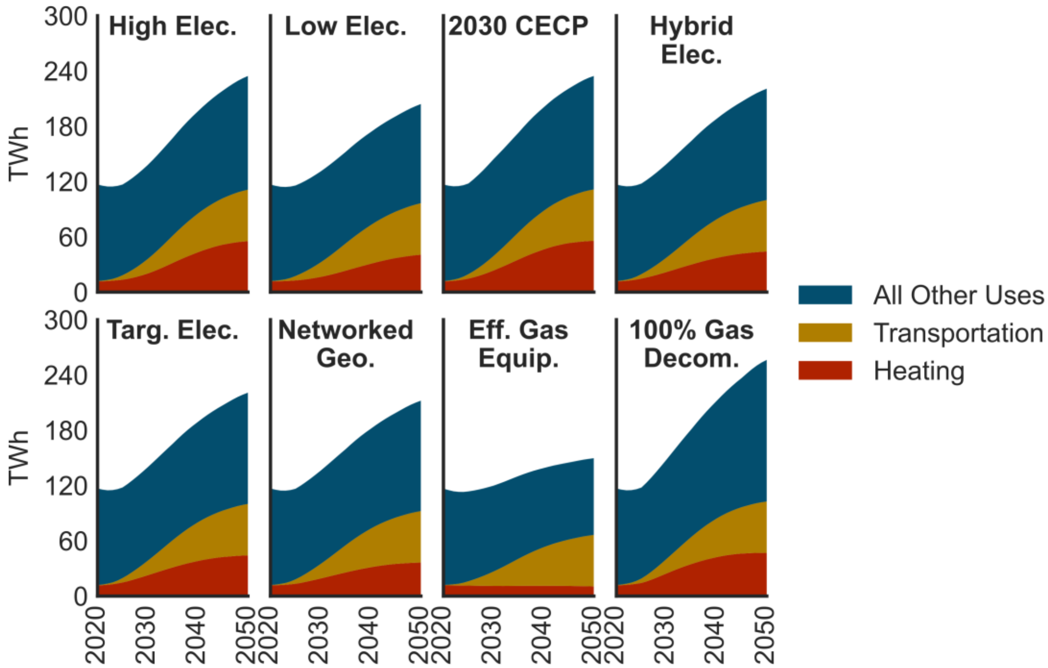
With just over 28 years until Massachusetts net-zero GHG target and an average lifetime of heating appliances of 16 to 19 years, there are only a handful of conversion opportunities for any given building. Most scenarios assume that equipment in buildings, and throughout the economy, is replaced at end-of-life. However in the Networked Geothermal, Targeted Electrification and 100% Gas Decommissioning pathways, conversion of some building equipment is assumed to take place before the end of equipment lifetimes. This assumption reflects that conversions of electric technologies in these scenarios are tied to GSEP and other infrastructure replacement needs, rather than equipment end-of-life.

Role and Use of the Electric Sector

Electric Peak Impacts

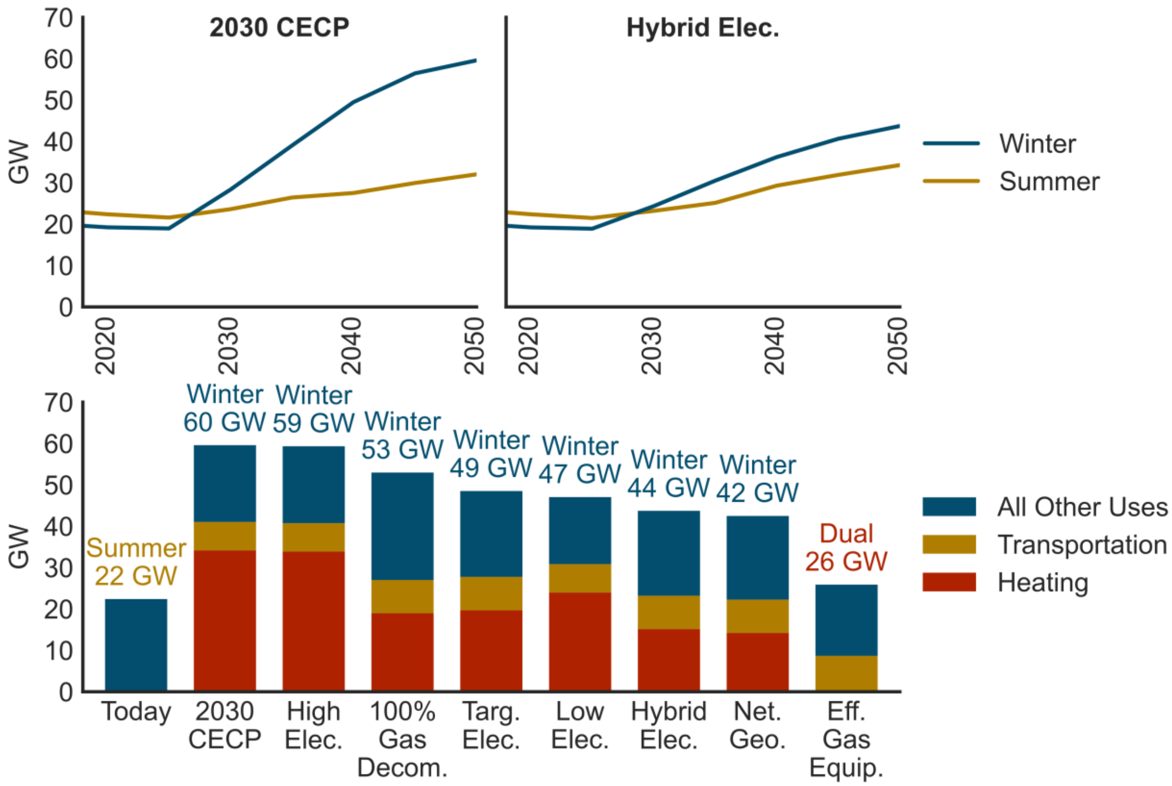
As a result of various levels of electrification across the economy by 2050, all pathways result in electrification-driven load growth as shown in Figure 19 (electric load impacts are presented for the Independent System Operator of New England, or ISO-NE, as a whole). Figure 19 shows that load growth driven by building and transportation electrification outpaces energy efficiency gains by the late 2020s in all scenarios, nearly doubling today's level of total electricity sales in New England by 2050. Electrification loads are highest in the 100% Decommissioning pathway, where the industrial sector is assumed to electrify where technically feasible (included in the "All Other Uses" category in the figure).

Figure 19. New England end-use electric loads (TWh) over time by scenario and sector. Note that loads are on the customer side and are thus not grossed up by transmission and distribution losses.



Electric load growth, especially driven by a transformation of heating supply, has large impacts on electric peak demands in the New England region. Pathways that include high levels of electrification with ASHPs see a substantial increase in electric peak requirements, as the efficiency of ASHPs declines as a function of temperature. This means that, especially in New England's cold weather, electrification of space heating results in substantial increases in electric peak demand in cases where electricity is required to deliver heat during the coldest hours of the year.

Figure 20. ISO-NE median peaks after load flexibility for all scenarios. The upper half of the figure shows the transition of ISO-NE in two example scenarios from a summer- to winter-peaking system in mid- to late-2020s. The lower half of the figure shows the 2050 system peak, sorted in descending order.



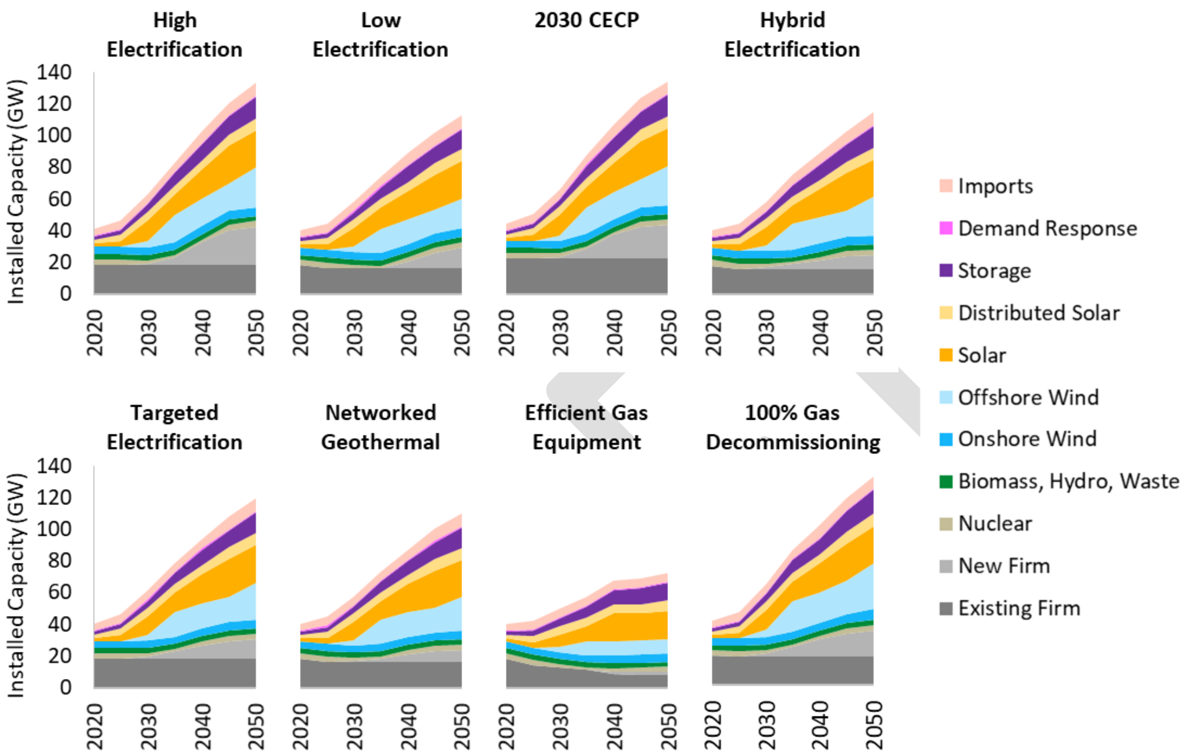
As shown in Figure 20, New England converts from summer- to winter-peaking as early as the late 2020s for those pathways relying heavily on electric heat pumps for space heating. As this figure illustrates, electric peaks in the New England region increase from approximately 22 GW in 2020 to over 64 GW by 2050 in the High Electrification and Interim 2030 CECP pathways. Peak demands on this chart are shown after load flexibility, which reduce system peak demands between 4.7 and 5.6 GW, depending on the pathway. For load flexibility, E3 assumes that portions of water heating and light-duty EV charging loads can be shifted outside of peak hours, as further described in Appendix 1. It is important to note that this analysis is sensitive to heat pump efficiency assumptions: as already illustrated in Figure 17, electric peaks can be reduced up to 10 GW if improved air-source heat pump technology is available and widely installed.

Peak demands are reduced substantially in electrification scenarios that include hybrid heat pumps, ground source heat pumps and networked geothermal systems, with 2050 peaks between 42 and 53 GW, depending on the pathway. GSHPs and networked geothermal systems reduce electric peak demands compared to pathways with larger reliance on ASHPs because these technologies are not sensitive to outside temperature. The Hybrid Electrification pathway reduces electric peak demands as space heating demands are supplied by gas during the coldest hours of the year, substantially reducing the amount of electric infrastructure required to serve peaks.

Installed Generation Capacity

As a result of the heating electrification-driven load and peak demand impacts described in the previous section, installed electric generation capacity in New England across pathways increases by 2 to 3 times by 2050, as shown in Figure 21. These results illustrate how large amounts of wind (especially offshore wind), solar and storage are required to decarbonize electric supply in line with the Commonwealth's climate goals, the magnitude of which depends on annual load and peak growth by scenario.

Figure 21. Total installed electric capacity in the ISO-NE region over time by scenario and resource type.



As Figure 21 illustrates, the highest amounts of installed capacity in the New England region are required in the High Electrification, Interim 2030 CECP and 100% Gas Decommissioning pathways, mostly as a result of the significant increase in space heating-driven energy and peak demands. Installed generation is lowest for the Efficient Gas pathway, which does not rely on electricity to meet space heating demands.

Large builds of renewable resources are required across all pathways in order to meet Massachusetts' climate goals by 2050. This includes between 14 and 36 GW of wind capacity (onshore and offshore) and between 25 and 32 GW of solar capacity (utility-scale and distributed) by 2050 in New England.[46]

The portfolios of electric resources shown in Figure 21 are cost optimized. As part of a least-cost portfolio, each scenario includes forms of low-carbon, non-weather-dependent resources to ensure reliability during critical periods, including peak demand days and periods with sustained low generation from weather-dependent renewables ("dunkelflaute"). The need for reliability is especially critical in scenarios that rely on electricity to meet New England's cold climate heating demands. Although this role can be filled by weather-dependent renewables and energy storage in theory, doing so requires substantial resource overbuilds and disproportionally high system costs. For instance, in prior work,[37] E3 estimated the required installed capacity of the New England system under deep decarbonization without the use of combustion-related resources as firm capacity. That study found that eliminating combustion in New England would require 51 GW more renewables and 126 GW (710 GWh) more energy storage compared to an electric system using combustion as firm capacity. For reference New England today has about 1.5

[46] More detail on electric modeling assumptions is provided in Appendix 1.

GW wind, 1.8 GW solar, and 1.8 GW storage capacity installed.[47] Similar findings can be found in studies across various climates and jurisdictions.[48]

In this analysis, the need for clean, firm capacity is supplied by hydrogen. Hydrogen is assumed to be available as a "drop-in" renewable fuel that can be blended in with natural gas at increasing percentages by mid-century, under the assumption that hydrogen can be partly deployed using existing infrastructure with relatively moderate technology adjustments. Other possible technologies that can provide similar services include, but are not limited to, natural gas with carbon capture and storage (CCS) capability, advanced nuclear reactors (including small modular reactors), and various forms of long-duration energy storage. Given these alternatives, E3 and other researchers continue to evaluate the role of these technologies in a future, deeply decarbonized grid as the technologies become more commercially mature.[49]

As shown in Figure 21, the needs for firm capacity are highest in scenarios with large amounts of electric heating. For example, in the High Electrification scenario, required firm capacity increases from approximately 18 to 43 GW between 2020 and 2050. In contrast, scenarios that leverage the gas system to provide peaking services (e.g., Efficient Gas Equipment, Hybrid Electrification, Networked Geothermal, Targeted Electrification) would need 10-30 GW firm electric capacity by 2050.

Importantly for all scenarios, as weather-dependent renewable penetration grows, firm resources are expected to primarily provide peaking capacity during critical hours and are therefore dispatched less frequently than combustion generators are today. Although the capacity of firm resources increases substantially, the capacity factors of these resources fall below 10% by 2050 as they are only utilized in a limited amount of hours of the year.

In addition to the installed capacity requirements within the New England region, renewable capacity outside of New England would be required for decarbonized fuel production supplied to Massachusetts, as all scenarios rely on renewable fuel production from outside of New England. This is especially true for those scenarios that rely more on gas for heating. For example, approximately 50–70 GW of dedicated renewable capacity would be needed in the Efficient Gas Equipment pathway to produce hydrogen and synthetic fuels required by all sectors in this pathway. This requirement is further detailed in Chapter 5.

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[47] From ISO New England's 2021 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT). https://www.iso-ne.com/system-planning/system-plans-studies/celt.Excludes data on distributed solar.

[48] See, for example:

(a) E3. 2019. Resource Adequacy in the Pacific Northwest. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf.

(b) Shaner, M. R., Davis, S. J., Lewis, N. S., & Caldeira, K. (2018). Geophysical constraints on the reliability of solar and wind power in the United States. *Energy & Environmental Science*, 11(4), 914-925. https://doi.org/10.1039/C7EE03029K.

(c) National Renewable Energy Laboratory. 2021. LA100: The Los Angeles 100% Renewable Energy Study Executive Summary. https://www.nrel.gov/docs/fy21osti/79444-ES.pdf.

(d) Princeton University Net Zero America Interim Report. 2021. https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

(e) Long, J. C., Baik, E., Jenkins, J. D., Kolster, C., Chawla, K., Olson, A., ... & Hamburg, S. P. (2021). Clean firm power is the key to California's carbon-free energy future. *Issues in Science and Technology*. https://issues.org/california-decarbonizing-power-wind-solar-nuclear-gas/.

[49] Some of E3's existing work examines the feasibility of these "clean firm" technologies in more detail, both qualitatively and quantitatively. See, for example:

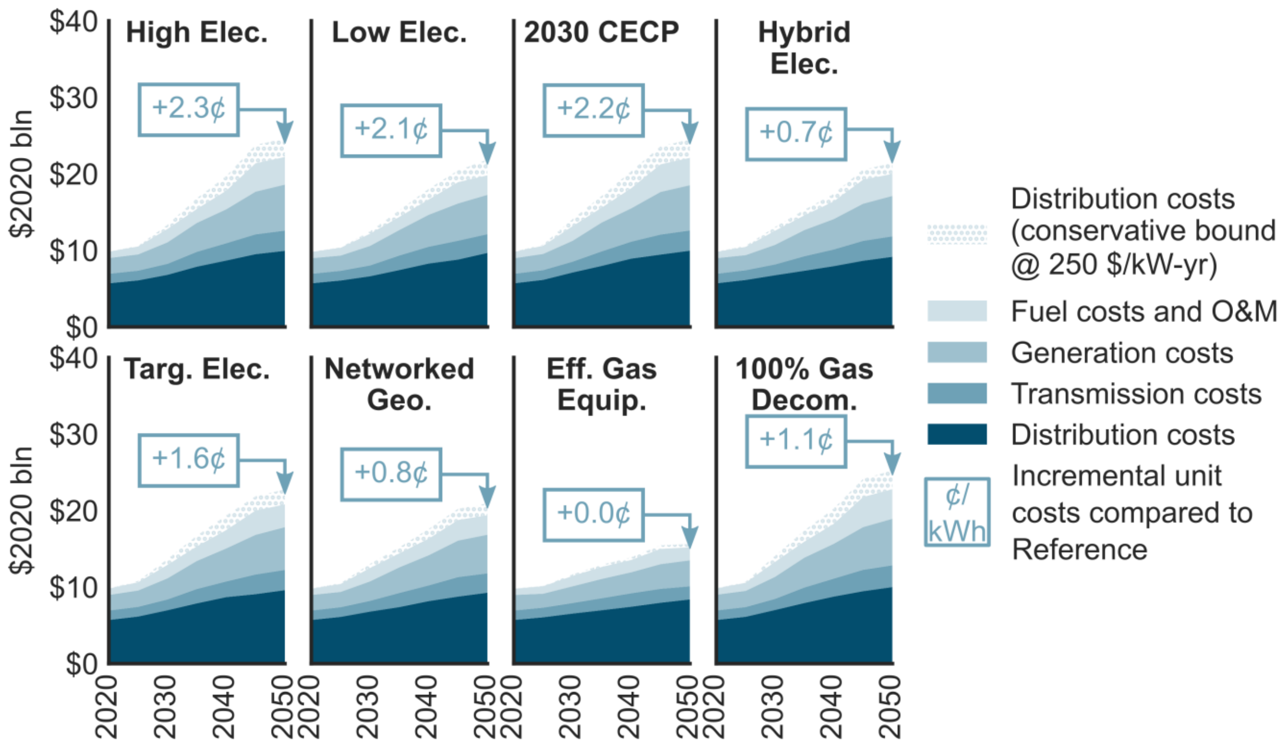
(a) Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future. November 2020. https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf.

(b) New York State Climate Action Council Draft Scoping Plan. Appendix G: Integration Analysis Technical Supplement. December 2021. https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scopping-Plan-Appendix-G-Integration-Analysis-Technical-Supplement.ashx. (See Section I page 47–52.)

Costs of the Electricity System

Each scenario sees a large increase in electric sector expenditures due to investments in generation, transmission, and distribution. These expenditures increase the annual cost of the electric system and impact unit costs, as shown on Figure 22.

Figure 22. Massachusetts electric revenue requirement over time by scenario and cost component. 2050 incremental average electric unit costs relative to the Reference scenario indicated on their respective panels.



This figure illustrates how costs of the electric system in the state of Massachusetts may increase from approximately $9 billion per year today to up to $25 billion per year by 2050, especially in those pathways with large amounts of electrification. Pathways that include a mix of electrification technologies, including hybrid strategies, generally involve lower electric system costs. For instance, the difference in electric sector costs for the Hybrid Electrification and Targeted Electrification pathways compared to the High Electrification pathway are up to $5 billion and $2.6 billion by 2050 respectively.

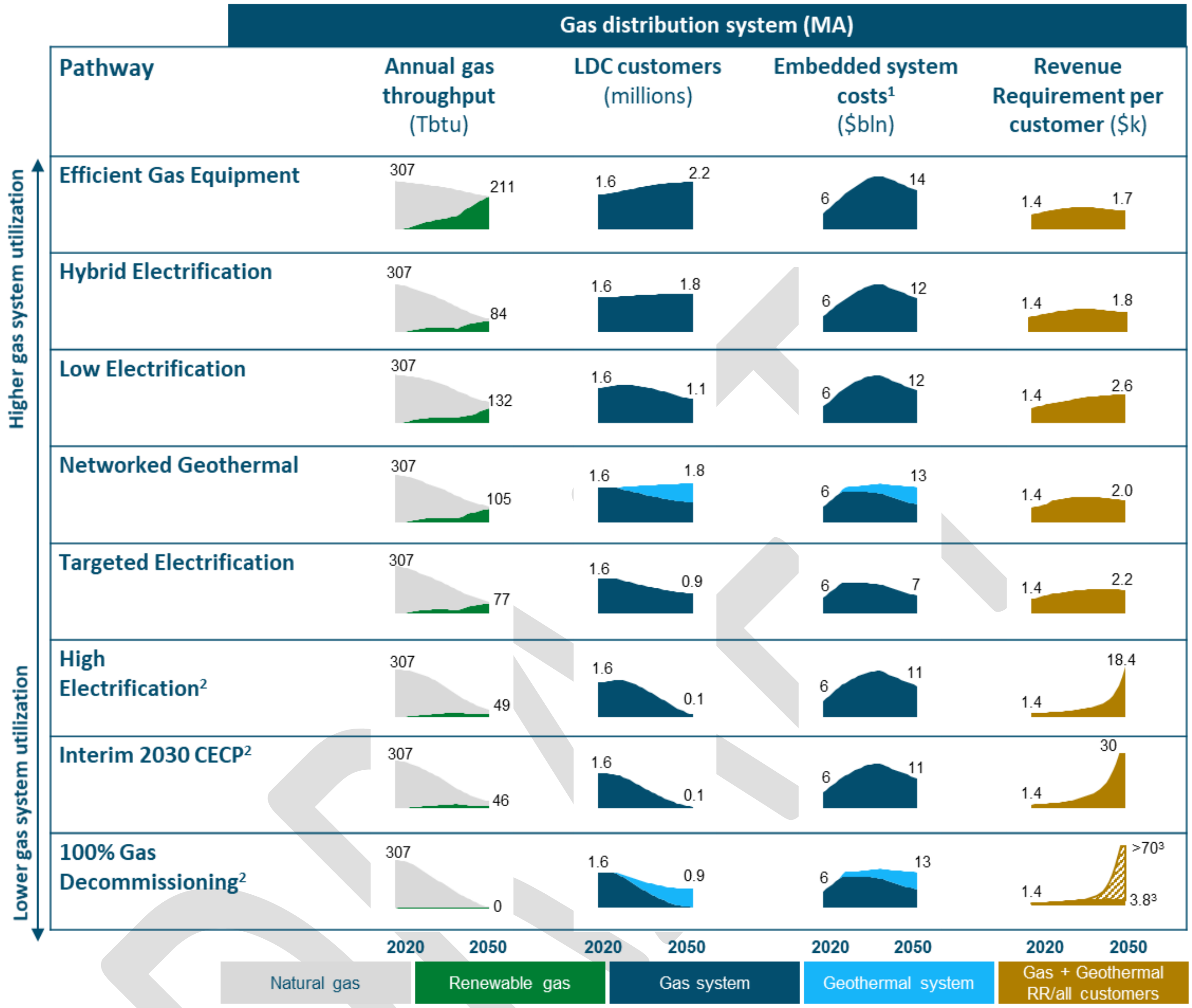
Unit cost impacts, measured as total costs of the electricity system divided by total electric loads, increase up to 2.3¢ per kWh incremental to a Reference pathway. The rate impacts of electric infrastructure additions are lower than revenue requirement increases because, as described above, electricity sales in Massachusetts double across most scenarios as a result of increased loads in the transportation, industrial and building sector. This implies that although total required investments in the electricity system are substantial in the coming decades, these costs may not result in significant cost shocks for electric customers. It is important to note however that E3 did not perform a detailed Revenue Requirement analysis of Massachusetts' electric utilities similar to the Revenue Requirement analysis developed for the gas LDCs, nor a detailed analysis of rate impacts for specific customer classes. Instead, E3 established a top-down approach to estimate electric rates for the residential and commercial sector that are used in the customer affordability analysis, as described in Appendix 1. The unit costs shown on Figure 22 represent a society-average unit costs, driven by increased costs and loads across sectors. In addition, this analysis involves substantial uncertainties, for instance on the costs of distribution system impacts that have not been studied in detail here.

Role and Use of the Gas System

Previous sections described how all decarbonization pathways result in a transformation of gas supply towards renewable fuels over time, indicating that decarbonization requires a substantial transformation of gas supply regardless of the pathway pursued. In addition to these changes, the decarbonization strategies each have different implications for the role and use of the gas delivery system in a decarbonized future, with different implications for infrastructure needs. While some pathways, such as the 100% Decommissioning pathway, see a complete phase out of natural gas distribution by 2050, other pathways rely on gas infrastructure to meet peak space heating needs in buildings during the coldest hours of the year (Hybrid Electrification), or maintain the gas delivery system to serve energy demands using a blend of renewable gases (Efficient Gas Equipment). Overall, each of the pathways provides its respective operational challenges to achieve the magnitude of transformation envisioned.

Figure 23 provides an overview of how the various pathways would impact the gas distribution system, looking at the key metrics of annual gas throughput, number of gas customers, total natural gas revenue requirement, and gas revenue requirement per customer. These metrics provide an overview of how the gas distribution system would be affected under each pathway.

Figure 23. Role and use of the gas system over time. ($ shown in real $2020).



¹Expressed as gas plus geothermal system rate base assuming optimistic cost reductions & optimistic geothermal costs.
²Scenarios with lowest gas system utilization bear the risk of ending up with embedded system costs that can no longer be recovered.
³100% Decommissioning pathway shows Revenue Requirement if costs are shared over all geothermal customers (bottom), versus if costs are shared over gas customers only (top).

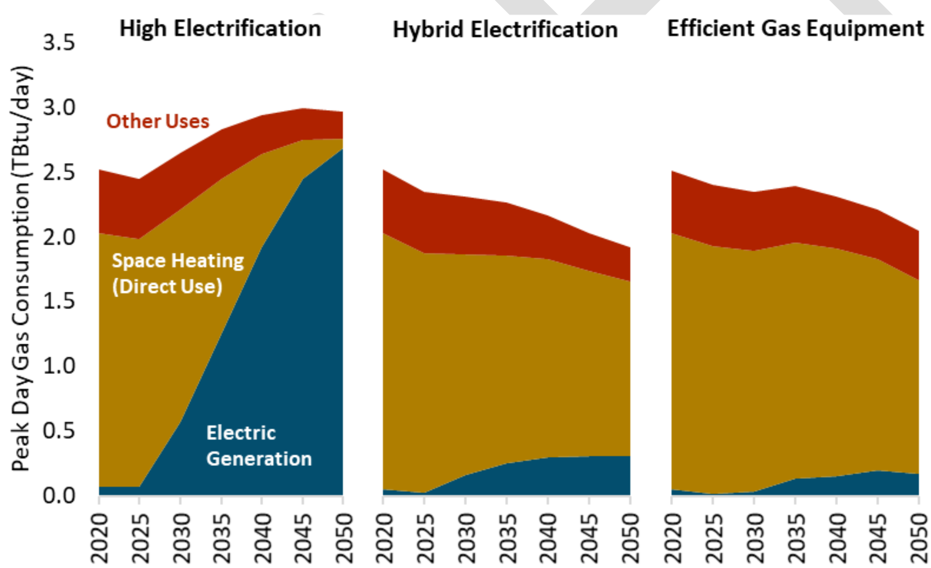
Gas Throughput & Supply

The decarbonization pathways analyzed see substantial changes in pipeline gas throughput, as well as the utilization of the gas system, over time. Although all pathways experience a decline in natural gas volumes as a result of energy efficiency, the decline in natural gas throughput is most prominent for those pathways that include large amounts of electrification. For example, in the 100% Gas Decommissioning pathway that envisions the full decommissioning of the natural gas distribution system by 2050, natural gas volumes are fully eliminated by that year. In contrast, the Efficient Gas Equipment pathway continues to rely on gas through 2050 for the majority of building heating needs, requiring a transformation of gas supply towards renewable fuels as described earlier.

In considering potential changes to the physical assets of the gas system, it is important to note that annual gas volumes are not a good indicator for gas infrastructure needs. Rather, gas infrastructure is planned, developed, and operated to serve customer needs at peak, which is reflected in a utility's "design day (further discussed in Chapter 5)." For example, the Hybrid Electrification pathway shows a substantial reduction in gas volumes by 2050, but a much smaller reduction in peak gas use on cold winter days. Therefore, those pathways that still rely on gas to supply heating needs in winter require the maintenance of the gas system infrastructure through 2050.

In addition, although pathways that rely heavily on electrification substantially reduce both the volume and utilization of the gas distribution system, these scenarios may see a shift of gas volume from the distribution system to electric generation, as renewable gas can be delivered to power generators to provide firm capacity on the electric system, as described earlier. Figure 24 provides an illustration of peak gas supply needs for three diverse pathways if zero-carbon electric firm capacity is supplied by hydrogen delivered through the gas system. This figure implies that gas infrastructure associated with meeting peak demands may increase in those pathways with higher levels of electrification (e.g., High Electrification). In addition, as the peak day gas demand profile shifts from direct-use to electric generation, there will likely be pipeline operational implications and potential contractual implications as the current operation of the New England pipeline system would need to accommodate the revised demand profile.

Figure 24. Illustration of changes in peak winter day gas volumes for three decarbonization pathways. Total gas volumes include zero-carbon pipeline gas, including hydrogen.

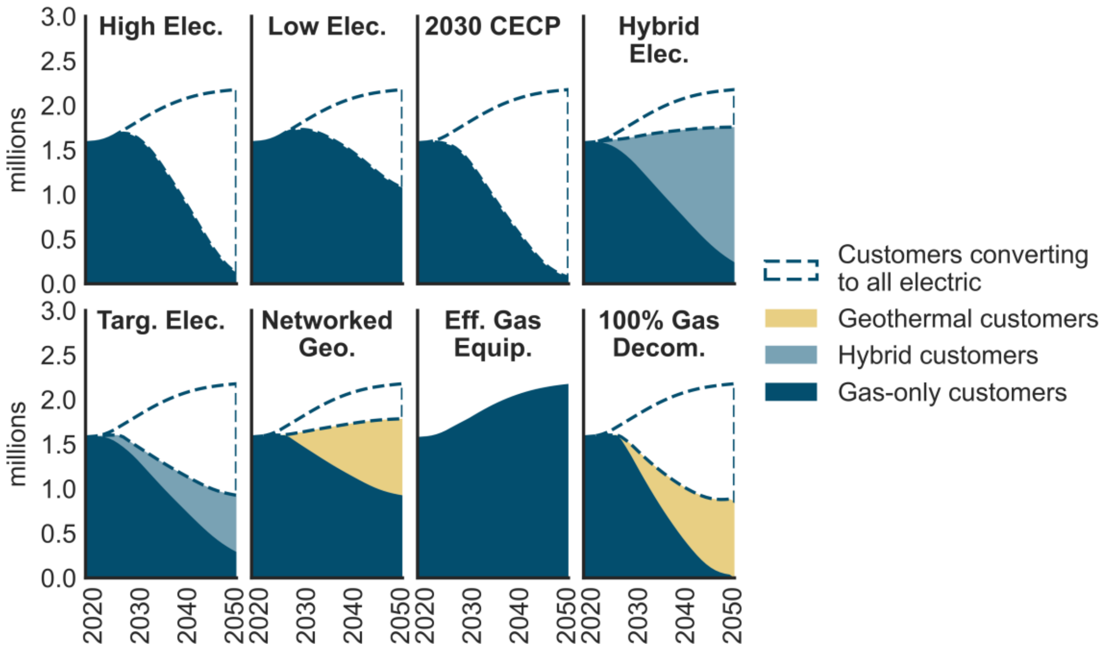


LDC Customer Base

Differences among pathways in the role and use of the gas system are largely reflected in the transition of the LDC customer base (Figure 25). The number of LDC customers varies by scenario in the following ways:

- Pathways with high levels of all-electric buildings see a net decline in LDC customer base.
- Pathways with high levels of hybrid electrification see a net increase in customer base, with a large reduction in annual gas volume used by customer.
- Pathways that involve networked geothermal systems transition from an LDC customer base relying on gas heating to an LDC customer base relying on geothermal heating.

Figure 25. Transition of LDC customers over time by pathway and customer type.



An important consideration in comparing differences in LDC customer base is the transition to networked geothermal systems. Both the Networked Geothermal and the 100% Decommissioning pathways assume that part of the LDC gas customer base transitions to these systems. Networked geothermal systems are assumed to be installed as an alternative to some GSEP projects and other gas infrastructure replacement programs, as described in more detail in Appendix 1. For this analysis, it is assumed that customers who transition to geothermal systems remain customers of their gas LDC, who is responsible for financing the infrastructure related to those systems. This requires a substantial evolution of the LDC business model, as further described below.

Gas Infrastructure & Revenue Requirement Implications

Given the varying role and use of the gas system by 2050 under different pathways, the Consultants analyzed the potential implications of decarbonization on the gas system by estimating the costs to maintain gas infrastructure throughout 2050. This analysis, presented in terms of the LDCs' annual Revenue Requirement, considers capital costs to replace existing infrastructure and to build new infrastructure where required, as well as the costs to operate and maintain the gas system through 2050 to provide safe and reliable service.

Figure 26 provides an overview of the 2020 net book value of assets of the Massachusetts LDCs combined. This figure represents the original costs of installed utility plant (physical gas system assets) on the Massachusetts gas distribution system less accumulated depreciation. This net book value is also referred to as a utility's rate base. As the figure illustrates, approximately 66% of the LDCs rate base is accounted for by mains, and approximately 26% by services & meters. These costs are recovered through a utility's annual Revenue Requirement.

Figure 26. Estimated net book value (rate base) of combined LDC assets. Values beyond the LDC's depreciation studies are estimated based on past GSEP investments.

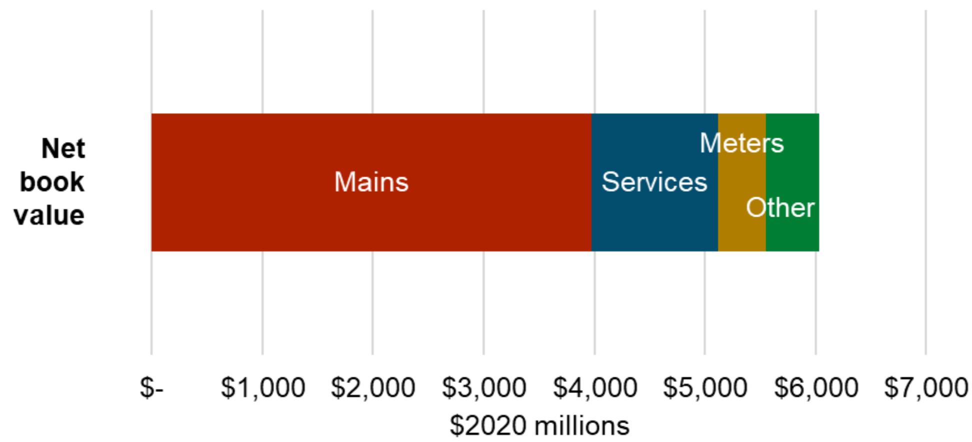
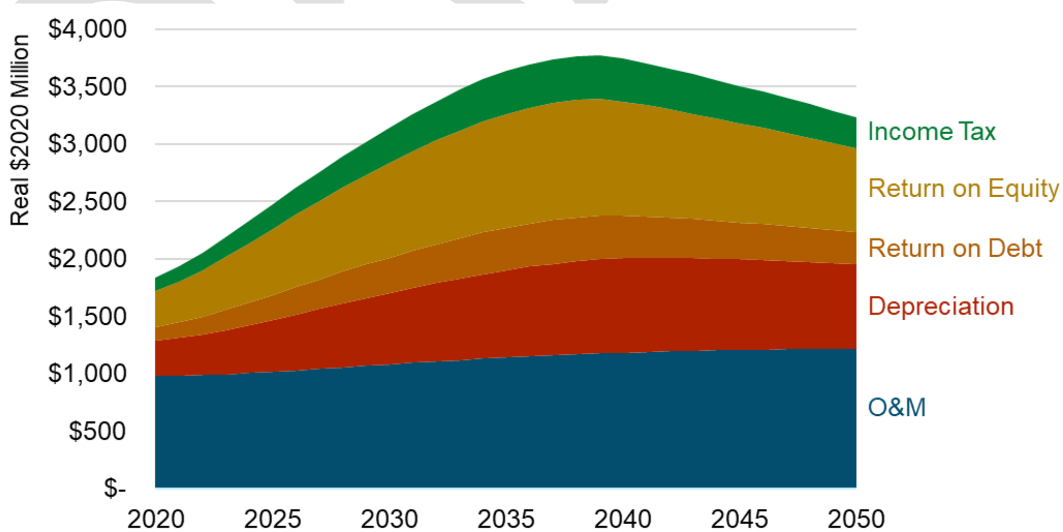


Figure 27 illustrates the aggregated LDC gas revenue requirement over time for a reference pathway. This figure provides an order of magnitude of the different components defining annual gas system costs over time. Five components are modeled: O&M (operations and maintenance), Depreciation (and accruals for removal costs), Return on Debt (based on the value of the rate base), Return on Equity (based on the value of the rate base), and Income Tax. The figure illustrates that the LDCs are expected to experience a significant increase in gas system costs through the mid 2030s. Although part of this increase is driven by customer additions, a large driver of near-term cost increases is the GSEP program, which is scheduled to be completed by 2039. More details on the revenue requirement modeling approach and the impact of GSEP are provided in Appendix 1.

Figure 27. Seven-LDC combined Revenue Requirement over time for a Reference pathway.

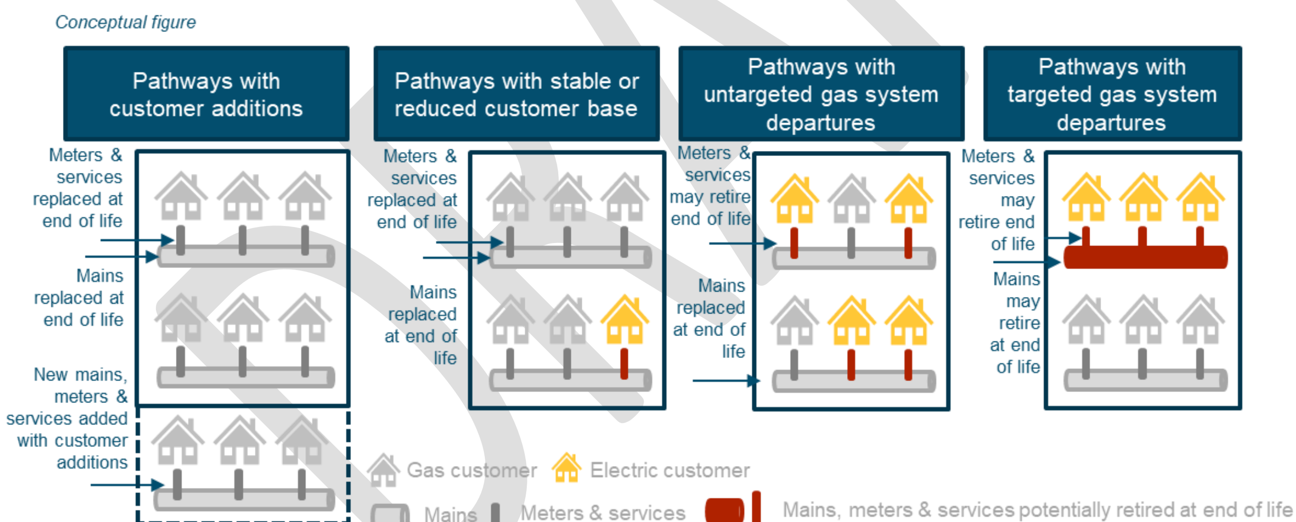


In estimating gas infrastructure requirements by pathway, the Consultants categorized the decarbonization pathways into four types:

1. **Pathways with sustained customer additions (Efficient Gas Equipment)**. These pathways see continued gas system utilization and an increase in infrastructure needs as a result of new customer connections.
2. **Pathways with a stable or reduced customer base (Hybrid Electrification, Low Electrification)**. In these pathways, the gas system largely needs to be maintained to serve building heating needs.
3. **Pathways with untargeted gas system departures (High Electrification, Interim 2030 CECP)**. These pathways see customer departures in a manner that is not geographically targeted. Because departures in these pathways are "untargeted", large portions of the gas system need to be maintained to serve customers remaining on the system.
4. **Pathways with targeted gas system departures (Networked Geothermal, Targeted Electrification, 100% Gas Decommissioning)**. These pathways see customer departures through a geographically planned approach. As such, more opportunities may exist for decommissioning network assets that serve multiple customers. Customers who electrify and customers who convert to networked geothermal systems fully disconnect from the gas system.

Each of these categories has different implications for the size and scope of the gas system, as well as for opportunities related to asset decommissioning and cost avoidance. For instance, where pathways with untargeted gas system departures still require the replacement of mains at the end of their lifetime, pathways with targeted gas system departures may see an opportunity for end-of-life retirement of some gas mains. This dynamic is conceptually illustrated in Figure 28.

Figure 28. Schematic of assumptions related to gas infrastructure cost avoidance categories.

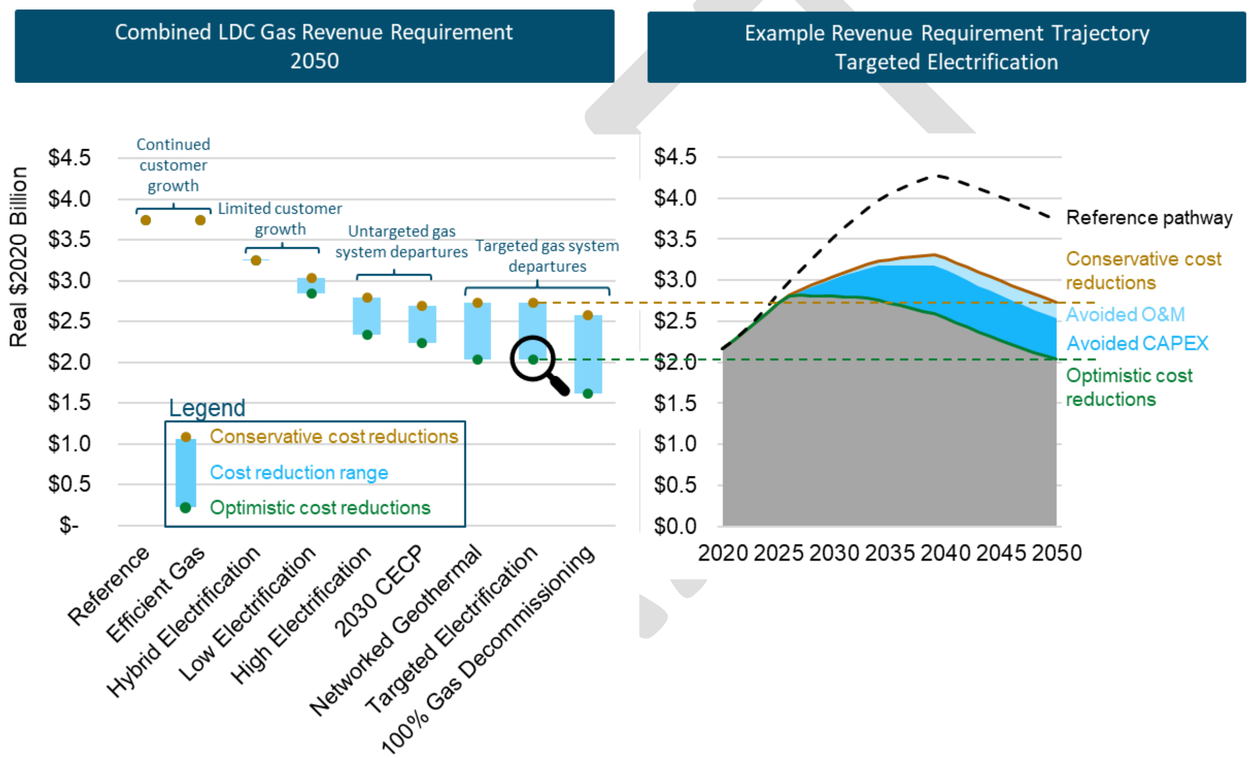


In considering potential cost savings on the gas system related to potential gas system departures consisted with the categories described above, E3 examined three kinds of cost avoidance opportunities:

- **Avoided O&M costs**: As customers depart the gas system, some O&M costs, particularly those related to customer service, may be reduced.
- **Avoided GSEP costs**: With targeted gas system departures, some GSEP costs corresponding to new mains, meters, and services may be avoided.
- **Avoided capital replacement costs**: With targeted gas system departures, some gas system assets may not need replacement at the end of their useful life.

As detailed in Appendix 1, the Consultants estimated a forecast of gas system infrastructure costs for the Massachusetts LDCs for each of the decarbonization pathways, taking capital replacement requirements and opportunities for cost avoidance into account. The Consultants' approach includes both an optimistic and conservative view to potential gas system cost avoidances. An overview of total LDC Revenue Requirement by 2050, including an example trajectory of the revenue requirement over time for the Targeted Electrification scenario, is provided in Figure 29. Note that this figure includes all aspects of the gas LDC Revenue Requirement, including a forecast of GSEP expenditures. The figure also includes a forecast of gas rate adders such as pension obligations and energy efficiency charges (for more details, see Appendix 1). This figure does not include gas commodity costs, nor the costs to build and maintain networked geothermal systems.

Figure 29. Range of gas LDC revenue requirements in 2050 and an example of the revenue requirement trajectory in the targeted electrification scenario.



In all pathways, annual LDC Revenue Requirement increases in the short term as a result of GSEP expenditures. By the mid 2030s, there is substantial divergence in the revenue requirement by pathway. In pathways with high levels of electrification, annual Revenue Requirement levels off in the mid- to late-2030s as a result of avoided investments to serve new customers and reduced reinvestment in the existing system.

Considerations for Targeted Electrification

As Figure 29 illustrates, pathways with targeted gas system departures show the largest opportunity for potential cost savings. The right panel of this figure considers the Targeted Electrification pathway in more detail. Compared to a reference pathway, the Targeted Electrification pathway sees considerable cost savings even under conservative cost reduction assumptions. This corresponds to avoided CAPEX investments to accommodate customer additions, as well as significant avoided investments in Meters and Services that are achieved by targeting electrification to deliberately avoid large portions of GSEP investment in these assets, as well as to avoid end-of-life asset replacement throughout the service territory. Optimistic cost reduction assumptions lead to further reductions in revenue requirement reflecting O&M cost reductions and some avoided investment in gas mains that may be attainable in a geographically targeted pathway. More details on the cost reduction cases are described in Appendix 1.

Targeted electrification combined with gas system decommissioning is a novel approach that has not seen widespread implementation by a gas utility to date. Therefore, substantial uncertainty exists in the estimating the feasibility of this approach and the potential for gas system cost avoidance. The potential to implement geographically targeted reductions in gas system investments under a networked geothermal or targeted electrification scenario is likely to involve several factors. Considerations include:

- **Whether specific gas distribution mains can be decommissioned while preserving system safety and reliability.** It may be that certain segments of the gas system cannot be removed from service without adversely affecting the safety, reliability, or other operational parameters of the system. On radial parts of the gas system, "terminal branches" can likely be decommissioned without broader impacts to gas system reliability. However, on networked parts of the gas system, engineering review may be necessary to determine whether specific mains can be decommissioned without negative safety or reliability impacts. For some network mains, decommissioning may not be possible without a reconfiguration of network infrastructure. Where it is possible to remove networked mains from service, additional valves, regulators, or other infrastructure may be needed to maintain system reliability. GSEP projects may occur in more dense and networked regions of the system and thus may not always be suitable for targeted electrification.
- **Whether a shift in system investments leads to societal cost savings.** Gas system decommissioning projects can avoid the capital costs of new gas system assets, as well as ongoing O&M costs associated with those assets. However, these projects will also entail costs related to the costs of decommissioning, building retrofits, and electric system upgrades. In addition, customers may need support purchasing new electric appliances, especially where these are more expensive than the gas alternative or where a customer's gas appliance is new or in good working order. Projects will be most attractive where concrete cost savings are achievable on the gas system and the magnitude of those savings exceeds the total costs of the decommissioning and targeted electrification project, providing net societal cost savings.
- **Whether 100% customer opt-in is required for conversion to alternative heating and cooking systems.** Under the current implementation of the utility obligation to serve, all customers will need to agree to convert from gas to electric and/or geothermal systems. Achieving 100% opt-in would be difficult for projects that include more than a handful of building owners, and the likelihood that all customers would agree to converting is likely small for large-scale projects. With regulatory changes to the obligation to serve, parts of the gas system could be removed from service without full support of customers, with important implications for customer choice as further described in Chapter 5.
- **Whether adverse customer bill impacts can be avoided.** Customers who participate in targeted electrification would be taking part in a communal project that provides benefits in the form of societal system cost savings and reduced GHG emissions. While access to brand-new appliances may be appealing, experience suggests that customers, particularly low-income customers, will not view targeted electrification projects as successful if their energy bills increase as a result. Bill guarantees may be necessary to ensure that customers are not adversely affected by participation in targeted electrification.

- **Whether community engagement is effective in reaching customers**. Targeted electrification can bring benefits to participants, especially under bill guarantees. However, customers may be hesitant to participate in these programs. Effective community engagement may help inform customers of the benefits of electrification and leverage the positive experiences of neighbors who have been involved in prior targeted electrification projects.

Gas System Decommissioning

A factor not shown in Figure 29 is the potential additional cost related to decommissioning of the gas distribution system. This consideration is especially relevant for the 100% Decommissioning pathway, where the use of gas is fully eliminated by 2050. Although LDCs collect costs for the removal of infrastructure at end of life per their depreciation studies, LDCs anticipate potential additional costs of decommissioning not captured in this analysis.

Given the unprecedented scale of transformation, not all decommissioning costs are quantifiable at this stage. These costs may relate to the decommissioning of underground facilities (gas mains, services, valves, district regulator stations), above-ground facilities (LNG, CNG, propane plants, district regulator stations, gate stations, gas mains on bridges, portably LNG equipment, training facilities, remote SCADA equipment, remote monitoring points, gas controls) and above-ground gas service appurtenances (gate box covers, risers, service regulators, meters). Some of these costs may be greater than the current accounting of asset removal costs currently recovered by the LDCs alongside annual depreciation expenses. The LDCs have identified the following categories as requiring further investigation and quantification:

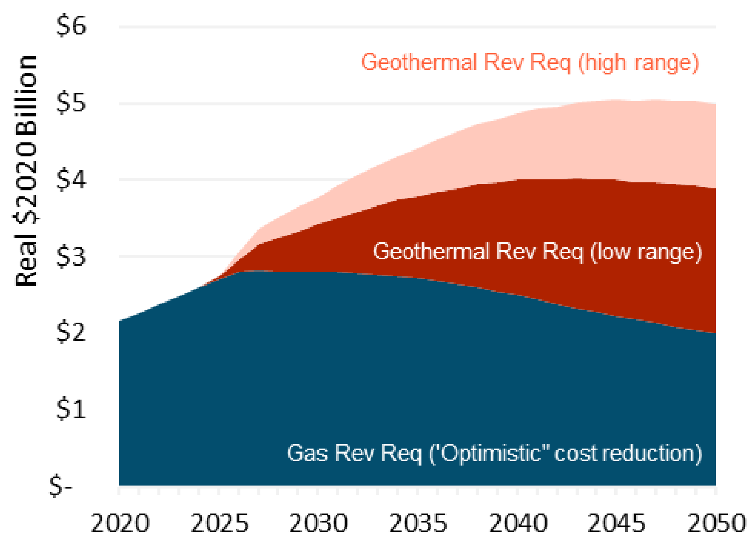
- Environmental remediation (environmentally sensitive areas, roads and railways, water crossings, remediation of historical spill sites, ongoing property maintenance)
- Abandonment/removal costs in excess of removal costs currently collected
- Product removal & cleaning (i.e. pre-abandonment pigging, temporary piping modifications, pipe testing for contaminants, waste disposal, and other)
- Appurtenances removal/modifications (i.e. meters, valve assemblies, warning signs, sumps & tanks, street permits, and other).
- Crossings (i.e. roads, railways, water crossings, utility crossings, and other)
- Pipe removal/abandonment in place (grading, trenching, cutting, coating, pipe transportation, cleanup, soil conservation measures, erosion control, and other).
- Potential temporary infrastructure to maintain safety and reliability
- Salvage value (sale or reuse of pipes, valves, fencing, land, etc)
- Regulatory approvals
- Landowner/public contact activities
- Long-term capacity contracts *(considered constant in scenario analysis)*
- Customer costs *(captured through costs of early retirements in scenario analysis)*

Revenue Requirement of Networked Geothermal Systems

Two decarbonization pathways, Networked Geothermal and 100% Decommissioning, include the transition of part of the LDC customer base to networked geothermal systems. As previously noted, it is assumed in this analysis that the costs of these systems are recovered by LDCs under cost-of-service regulation similar to current gas system cost recovery. Because networked geothermal systems entail relatively large capital expenditures, financing these costs through a utility with cost recovery over the lifetime of the assets may provide benefits in terms of customer costs, workforce opportunities and utility expertise.

Although the installation of networked geothermal systems at the scale envisioned in these scenarios is a novel approach that involves significant uncertainty, the Consultants estimated a forecast of Revenue Requirement specific to networked geothermal systems using the approach described in Appendix 1. Figure 30 provides an overview of total Revenue Requirement for the Networked Geothermal pathway, including estimated Revenue Requirement for the networked geothermal systems required in this pathway using a range of capital expenditure costs. This figure shows that although the Networked Geothermal pathway potentially reduces costs related to the gas system, an additional set of costs need to be considered associated with the installation of networked geothermal infrastructure.[50]

Figure 30. Forecast of revenue requirement including networked geothermal systems, for the Networked Geothermal pathway.



LDC Cost Recovery under Current Regulatory Framework

Under the current regulatory framework, LDCs recover the costs of maintaining the gas system through gas delivery rates. The majority of this cost recovery takes place on a volumetric rate basis, by allocating the revenue requirement to customer classes and then dividing class revenue requirement over class throughput. It is important to note that, especially in the context of decarbonization, volumetric rates do not provide a good comparison for annual gas costs to customers across pathways, as customers use dramatically different amounts of gas in different pathways.

To provide a comparison across pathways, Table 12 shows the average annual cost to gas customers for the gas delivery system, *i.e.*, the annual LDC Revenue Requirement divided by the number of LDC customers in each year. Table 12 shows that despite potential cost savings, pathways that experience a departure of customers to alternative heating strategies see a significant increase in per-customer costs, to an unmanageable extent on the long term. This effect occurs because as more customers leave the gas

[50] Networked Geothermal Revenue Requirements are based on HEET's GeoMicroDistrict Study, and solely include the cost of infrastructure (behind the meter customer costs are assumed to be borne by customers).

system, the costs of maintaining the gas system are shared over fewer customers. Further, the figure illustrates how:

- Pathways that rely heavily on continued use of the gas system show customer delivery cost increases that are comparable to a reference case. Note that this figure does not include commodity costs;
- Pathways with very low but continued gas system utilization see a ten to twentyfold increase in per-customer costs between 2020-2050;
- Scenarios that partly rely on gas, either through a mix of technologies or through hybrid usage of the system, see approximately a doubling of per-customer costs between 2020-2050.

Further implications of these dynamics, including effect on customer bills and affordability is described in Chapter 5. An overview of potentially regulatory changes to mitigate these impacts is provided in Part II of this Report.

Table 12 also includes an estimation of embedded gas system costs, expressed as remaining Rate Base, that remain after the modeling period. These embedded costs represent the book value of long-lived capital assets for all LDCs combined in 2050. Under optimistic cost reduction assumptions, these costs vary from $6.6 billion for pathways with targeted gas system departures (Targeted Electrification, 100% Gas Decommissioning and Networked Geothermal) to $14 billion for pathways with sustained customer additions (Efficient Gas). For the latter category, costs will continue to be recovered from customers after 2050 as customers remain connected to the system. However, pathways with significant gas system departures, such as High Electrification, Interim 2030 CECP and 100% Decommissioning, bear the risk that embedded costs can no longer be recovered. The effect of networked geothermal systems on embedded costs and Revenue Requirement per customer is shown separately in the table for the Networked Geothermal and 100% Decommissioning scenario. Although these pathways see increase system costs, costs per customer are mitigated as a larger portion of customers remain that may share in the recovery of combined costs of gas and geothermal systems. However, this option raises regulatory questions that are further discussed in Part II of this Report.

Table 12. Revenue requirement per customer over time by scenario. Scenarios with decreased gas system utilization have higher impacts on this metric than scenarios with continued utilization. The revenue requirement shown includes the cost of operating and maintaining the gas system and excludes supply costs.

Scenario	Cost Avoidance	Revenue Requirement per Customer ($2020)				Embedded system costs ($M)[1]
		2020	2030	2040	2050	Post-2050
Gas system only						
Reference	Optimistic	$1,360	$1,900	$1,990	$1,680	$14,030
	Pessimistic	$1,360	$1,900	$1,990	$1,680	$14,030
High Electrification	Optimistic	$1,360	$2,020	$3,740	$18,410	$11,330
	Pessimistic	$1,360	$2,040	$4,030	$22,060	$11,330
Low Electrification	Optimistic	$1,360	$1,930	$2,400	$2,580	$11,710
	Pessimistic	$1,360	$1,930	$2,450	$2,750	$11,710
Interim 2030 CECP	Optimistic	$1,360	$2,320	$5,480	$30,050	$10,990
	Pessimistic	$1,360	$2,390	$6,080	$36,250	$10,990
Hybrid Electrification	Optimistic	$1,360	$1,950	$2,120	$1,810	$12,460
	Pessimistic	$1,360	$1,950	$2,120	$1,810	$12,460
Efficient Gas	Optimistic	$1,360	$1,910	$2,000	$1,690	$14,140
	Pessimistic	$1,360	$1,910	$2,000	$1,690	$14,140
Networked Geothermal	Optimistic	$1,360	$1,860	$2,220	$2,160	$6,620
	Pessimistic	$1,360	$2,030	$2,830	$2,880	$10,310
Targeted Electrification	Optimistic	$1,360	$1,860	$2,220	$2,160	$6,620
	Pessimistic	$1,360	$2,030	$2,830	$2,880	$10,310
100% Gas Decommissioning	Optimistic	$1,360	$2,230	$5,590	$48,470	$6,620
	Pessimistic	$1,360	$2,510	$7,950	> $70,000[2]	$10,300
Gas + networked geothermal system						
Networked Geothermal	Optimistic	$1,360	$2,380	$3,140	$2,960	$12,950
	Pessimistic	$1,360	$2,530	$3,550	$3,480	$20,560
100% Gas Decommissioning	Optimistic	$1,360	$2,700	$4,500	$4,380	$12,950
	Pessimistic	$1,360	$2,910	$5,470	$5,940	$20,550

[1] Expressed as remaining rate base by 2050 across all LDCs combined. Scenarios with lower gas system utilization, such as High Electrification, Interim 2030 CECP and 100% Gas Decommissioning have an increased risk ending up with embedded costs that can no longer be recovered.

[2] With no customers left by 2050, costs can no longer be recovered through customers.

5. Implications of Decarbonization Pathways

This chapter describes key implications of decarbonization pathways for LDCs and their customers and provides insights into the feasibility of achieving each pathway. In assessing the implications of decarbonization pathways, the Consultants analyzed the quantitative and qualitative evaluation criteria introduced in Chapter 2. All evaluation criteria are described in detail in this chapter, providing a description of the criterion, its relevance to the research, a summary of key observations and findings from the analysis and any policy implications specific to that criterion.

It is important to note that factors such as GHG emissions reductions and impact on public safety are not assessed across pathways. These factors are assumed to be foundational to achieving the Commonwealth's climate goals. GHG emissions reductions are the same for all pathways, reaching 50% by 2030 and 90% by 2050 compared to 1990 levels, as illustrated in Chapter 4. Public safety is considered a fundamental component of LDC operations, and therefore not assessed independently across pathways.

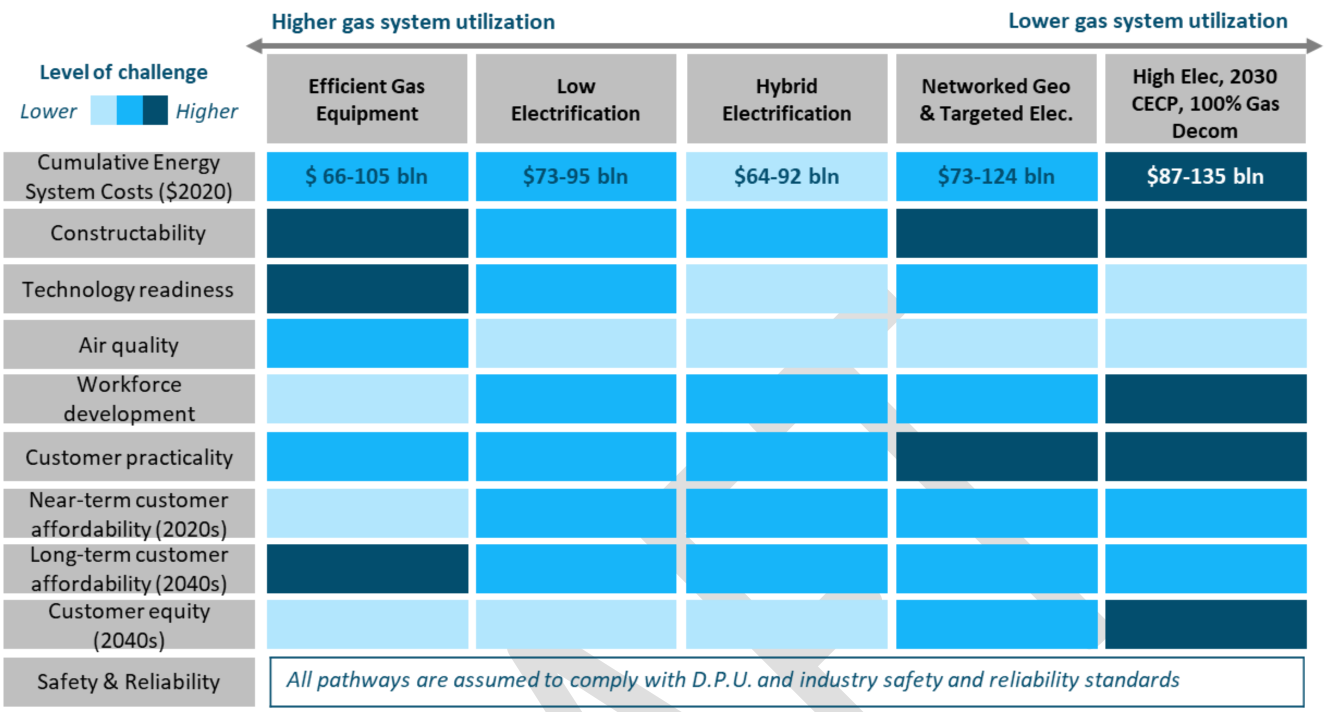
This chapter first summarizes key feasibility implications across evaluation criteria. Each criteria is then outlined in more detail in the subsequent sections.

Feasibility implications

Overview of Feasibility across Evaluation Criteria

The results of the Consultants' feasibility analysis are summarized in Figure 31. This figure shows the level of challenge for each of the evaluation criteria over time, where "challenge" is defined as the magnitude of change from current industry or customers practices and/or amount of policy intervention required.

Figure 31. Assessment of feasibility implications across evaluation criteria.



Metric	Definition
Cumulative Energy System Costs	The cumulative (simple sum) incremental annual cost of energy supply and delivery infrastructure, end-use equipment, and fuel costs, net of fuel savings, relative to the Reference scenario, 2020 - 2050. Higher costs implies a higher level of challenge. Costs are shown in real 2020 dollars, billions.
Constructability	The pace and scale of electric and gas sector infrastructure additions. Scenarios with higher overall infrastructure requirements of gas and/or electric equipment face a higher level of challenge.
Technology readiness	The extent to which a pathway relies on technologies that are commercially available. Renewable gases are less technologically mature; scenarios that rely on them face a higher level of challenge on this metric.
Air quality	Air quality is estimated based on 2050 fuel combustion in each scenario. Scenarios with more electrification have lower levels of combustion emissions and are assumed to result in lower levels of air quality challenge.
Workforce development	Estimate of the scale of the LDC workforce that will need to transition roles. Scenarios with high levels of electrification imply a more challenging worforce transition to train, or re-train, skilled workers.
Customer practicality	The pace, scale and types of customer-side retrofits required to achieve decarbonization. Scenarios with higher levels of heat pump and building shell adoption require more extensive and coordinated customer retrofit initiatives.
Near-term customer affordability	The total cost of ownership (TCO), including upfront capital costs, for LDC customers who adopt building decarbonization measures in the 2020s. Electrification is more costly for customers in the 2020s; indicating a higher level of challenge.
Long-term customer affordability	TCO for LDC customers who adopt building decarbonization measures in the 2040s. Increasing commodity costs of gas result in a higher level of challenge for scenarios relying heavily on gas.
Customer equity	The cost impact on LDC customers who do not adopt decarbonization technologies (“non-migrating”). Higher income customers are more likely to migrate than lower-income customers, absent policy intervention. Higher costs for low-income and non-migrating customers implies a higher level of customer equity challenge.
Safety & Reliability	All pathways are assumed to comply with D.P.U. and industry natural gas and electric safety and reliability standards. Those standards will need to be evaluated over time depending on how decarbonization proceeds.

The figure illustrates the following across evaluation criteria:

- **Energy system costs**. Cumulative energy system costs across scenarios range from $64 to $135 billion over the 2020-2050 modeling period. By 2050, costs fall within the range of $3.3 to $7.8 billion per year, or between 0.6% and 1.6% of today's Massachusetts Gross State Product. The Hybrid Electrification scenario that envisions an ongoing, though reduced, role for the gas system carries the lowest cumulative costs. In scenarios that continue to rely on gas over time, costs rise in the long term when the need for synthetic gases to achieve the Commonwealth's climate goals increases. Scenarios that rely to a large extent on all-electric strategies have higher energy system costs due to the higher cost of appliances and incremental electric infrastructure requirements.
- **Constructability**. Regardless of pathway, decarbonizing the Massachusetts building sector requires an unprecedented amount of energy infrastructure construction across all electricity value chain components. Pathways that require the most aggressive electrification of buildings present unique challenges given the immediate and sustained electric sector construction required throughout the entire analysis period. Pathways that rely on alternative heating infrastructure, such as the Networked Geothermal pathway, represent a significant change in the type of energy infrastructure built in the Commonwealth and may result in unique implementation challenges. Similar feasibility challenges may impact pathways that require significant construction of infrastructure to support production and delivery of renewable fuels, such as hydrogen. Pathways that continue to utilize gas distribution systems may offer more time to test, build, and implement solutions at scale, as the construction requirements generally fall later in the analysis period.
- **Technology Readiness**. The relative reliance on different technologies affects the risk profile of a scenario or decarbonization portfolio. For instance, higher reliance on renewable fuels, like in the Efficient Gas, adds risk to the Commonwealth's decarbonization portfolio as these technologies are ranked low on a Technology Readiness Level (TRL) scale. Technology risks are reduced, in relative terms, in scenarios like High Electrification that rely to a large extent on commercially available products.
- **Air quality.** The decarbonization pathways show differences in the reduction of fuel combustion and as such in the level of air quality benefits achieved. The Consultants' assessed the "level of challenge" based on the level of fuel combustion, where pathways with the largest reductions in combustible fuels compared to today are assessed as lowest level of challenge. As such, although the Efficient Gas Equipment pathway results in air quality benefits compared to today, this pathway sees lower air quality benefits compared to pathways with higher levels of electrification.
- **Workforce Development.** There are significant changes in electric and natural gas distribution investments across all the decarbonization pathways, which may impact the LDC workforce over the long-run, and require additional support for a growing electric industry workforce. Pathways with significant levels of electrification (i.e. High Electrification, Interim 2030 CECP, 100% Gas Decommissioning) may increase near-term demands on the LDC workforce, as gas workers will continue to be needed to support the safe and reliable operation of the system, and are likely to be needed to support targeted gas system decommissioning. Longer-term, these pathways imply significant changes to the LDC business models and therefore consequences for the LDC workforce. In addition, all pathways include substantial construction requirements associated with electric industry infrastructure, energy efficiency, and other energy delivery technologies like networked geothermal systems, which will result in increased demand for labor to support these

sectors. This overall expansion of the labor force may provide opportunities to retrain and transition the LDC workforce to the support these new or existing energy infrastructure sectors.

- **Customer practicality.** Pathways that require the most rapid conversion of natural gas customers to electric energy solutions present significant challenges for customers, regulators, and LDCs to change current customer behavior at an unprecedented pace and scale either through incentives or mandates. These pathways represent the most significant change to the existing policies that allow customers to choose their preferred energy solutions. Similarly, pathways that require group decisions (e.g., neighborhood conversion to alternative heating technologies) represent a significant change for Massachusetts customers, which may create substantial implementation and logistical challenges.
- **Customer affordability.** Under the current regulatory framework, there will be upward pressure on gas customer rates and bills driven by a combination of higher delivery costs and higher gas commodity costs across pathways. Delivery cost impacts are most acute in scenarios with high levels of electrification, whereas commodity cost impacts are highest in scenarios with lower levels of electrification where impacts grow over time as the Commonwealth's emissions budget tightens. Affordability results are particularly concerning for lower income customers given that the upfront cost challenges associated with fully electrifying a building makes it more likely they will experience increasing gas system costs.
- **Customer equity.** There are significant changes in natural gas distribution revenue requirements per customer across pathways. Pathways with high levels of electrification are likely to lead to significant cost shifts between migrating and non-migrating customers, resulting in equity concerns. These higher cost shifts will require more immediate, expansive, and significant regulatory actions to ensure equitable sharing of costs. Pathways that envision a sustained and growing natural gas customer base are generally less likely to result in cost shifting amongst customers and subsequently minimize equity issues and allow LDCs and regulators to utilize existing policies and structures to implement decarbonization strategies.

Detailed assessment of evaluation criteria

Energy System Costs

The energy system costs evaluated in this analysis includes all energy-related decarbonization costs, including costs of demand-side capital (EVs, space heating appliances, building shells, etc.), costs of energy infrastructure (electric, gas and networked geothermal) and costs of fuels.[51] The analysis considers a range of costs for categories with quantifiable levels of uncertainty introduced in Chapter 2. Note that this Study does not quantitatively consider the social costs of carbon or avoided costs related to health or environmental damage resulting from climate change.

Importantly, the Consultants' economy-wide cost analysis shows total incremental costs for the Commonwealth as a whole, without specifying how those costs should be paid for or allocated. For example, the demand-side capital costs primarily reflect the costs of upgrading buildings and home equipment, but the allocation of those costs (e.g., household expenses versus policy incentives or utility rate structures) is not defined in this part of the analysis.

[51] Costs of the energy system are assessed on an incremental basis, meaning that costs are compared against a reference pathway in which decarbonization targets are not met. This perspective elucidates and isolates the effects of decarbonization strategies on energy system costs specifically.

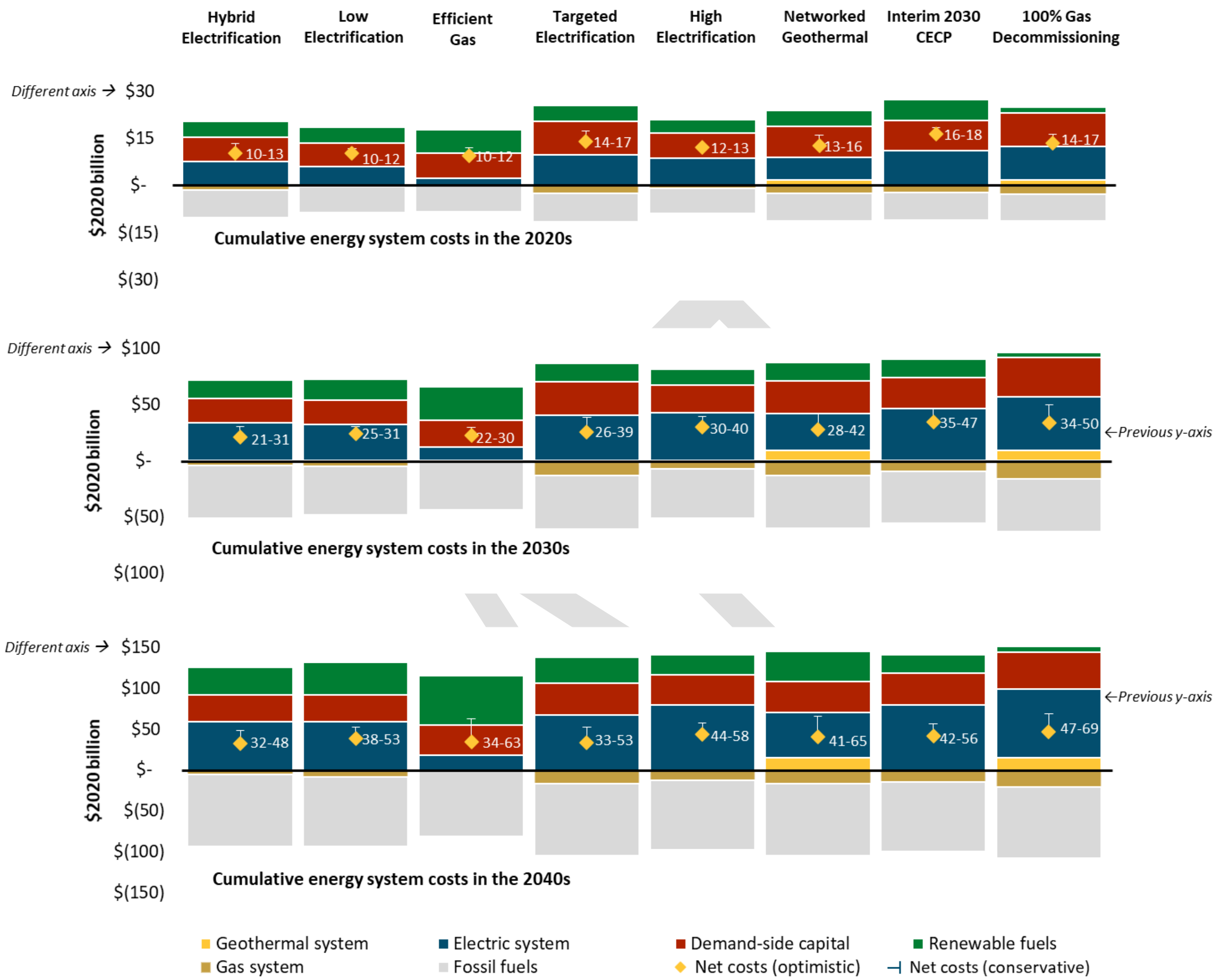
Key findings and observations

Cumulative incremental energy system costs by pathway between 2020-2050, relative to a Reference scenario, vary from $64-$94 billion in an optimistic view to $92 to $135 billion in a conservative view. By 2050, *annual* energy system costs range from $3.3–$5.0 billion per year in an optimistic view and $5.0–$7.8 billion in a conservative view.[52] Both over the entire modeling period and by 2050, the Hybrid Electrification pathway has lowest cumulative incremental costs, as this pathway balances the need for electric sector requirements, renewable fuel demand and demand-side capital investments. The 100% Decommissioning pathway shows highest costs on a cumulative basis. It is important to note that this scenario does not capture all costs associated with retiring gas infrastructure in Massachusetts, which require further study to fully identify as described in Chapter 4. Scenarios that rely on less commercialized options like hydrogen and SNG or networked geothermal systems are especially sensitive to cost assumptions, as they involve a larger uncertainty range.

Figure 32 provides an overview of cumulative energy system costs between the period 2020–2050, broken out in three decades. As such, this figure provides a comparison between short-term costs and long-term costs by scenario. An overview of costs per 5-year increment by scenario in table format is provided in Appendix 1.

[52] The optimistic view refers to a perspective with optimistic cost assumptions across the list of uncertainty parameters defined in Chapter 2.

Figure 32. Cumulative energy system costs by decade, by scenario.



A few general observations can be made from Figure 32.

- Cumulative energy system costs are highest in the long-term, mostly as a result of electric system costs and the costs of renewable fuels. This decade also shows the highest cost savings. In the short term (2020-2030), cumulative net system costs fall within a range of $10-18 billion, largely driven by a combination of electric system costs, demand-side capital costs and renewable fuels.
- All scenarios show substantial savings in the costs of fossil fuels, which are primarily the result of avoided gasoline and diesel costs in the transportation sector. These savings mostly occur post 2030. To a lesser extent, the pathways include avoided commodity costs of natural gas due to conversion to electric appliances and increased levels of renewable gases in the pipeline.
- The scenarios show varying levels of gas system avoidance costs. These savings are based on the potential for cost reduction and levels of decommissioning described in earlier sections of this Report and are largest for those scenarios that include a form of targeted, neighborhood-scale

electrification. Yet, avoided gas system costs are small relative to the investment costs required in other sectors.

- All scenarios require substantial investments in demand-side capital costs, mostly concentrated in the Transportation sector (representing the costs of electric vehicles) and in the Building sector (representing the costs of heating equipment and building shell upgrades). These demand-side costs are highest for pathways with significant levels of electrification and building retrofits, such as High Electrification, Interim 2030 CECP and 100% Decommissioning. The Hybrid Electrification scenario minimizes these costs by reducing dependence on building envelope measures as electric sector peak impacts are mitigated by using the gas system.
- Scenarios with high levels of electrification also show the largest incremental costs in electric generation, distribution and transmission, which account for up to $140 billion in incremental costs within the 2020-2050 timeframe for the 100% Decommissioning scenario. Incremental system costs are lowest for the Efficient Gas Equipment scenario, which requires a total of $33 billion in cumulative costs over the 2020-2050 time period.
- The Efficient Gas Equipment scenario shows the largest annual incremental costs for renewable gas of up to $68 billion within the 2020-2050 timeframe in an optimistic view. Note that the conservative view on renewable gas costs would raise these costs to $98 billion, largely defining the relatively large range in net system costs by the 2040s. This indicates that high levels of uncertainty and risk exist around the costs and availability of renewable gases.
- Scenarios that include the installation of networked geothermal systems add cumulative costs by $27-42 billion between 2020-2050, though these scenarios generally show lower costs on the electric system as they avoid part of the “peak heat challenge” discussed in this Report.

Importantly, net energy system costs vary substantially over time, with distinct differences by pathway. Some pathways, such as the Interim 2030 CECP pathway, require investments in the near-term, as a result of more aggressive adoption of heat pumps and building shell retrofits by 2030. In contrast, the Efficient Gas pathway has higher costs toward the end of the modeling period, as this pathway relies on large-scale adoption of synthetic gases from 2040 onwards. In all scenarios, costs increase after the 2030s, mainly as a result of accelerated adoption of decarbonization technologies and associated system costs.

Over the entire modeling period, the Hybrid Electrification pathway has lowest cumulative incremental costs, as this pathway balances the need for electric sector requirements, decarbonized fuel demand and demand-side capital investments. The 100% Decommissioning pathway shows highest costs on a cumulative basis. It is important to note that this scenario does not capture all costs associated with retiring gas infrastructure in Massachusetts, which require further study to fully identify as described in Chapter 4. Scenarios that rely on less commercialized options like hydrogen and SNG or networked geothermal systems are especially sensitive to cost assumptions, as they involve a larger uncertainty range.

Policy implications

Based on the Consultant’s research, analysis, and modeling results there are various policy implications associated with the pathways’ economy-wide costs, including:

- **Need for consumer incentives.** The demand-side capital investments required for building appliances and shell upgrades are substantial across all pathways, reaching between $73 and $97 billion cumulative between 2020-2050, or an average of between $2.4 and $3.2 billion annually. It is unlikely that these costs can be carried solely by households, particularly low and moderate income households. Therefore, achieving deep decarbonization, regardless of the pathway pursued, will likely require additional consumer incentives similar to the incentives currently offered through MassSave.

- **Maintaining utility credit.** Given the magnitude of required infrastructure costs across all pathways, there may be a need for policy changes related to financing future infrastructure projects. For example, all investments in electric infrastructure will require some form of credit support (e.g., long-term power purchase agreements) as the electric distribution companies, the Commonwealth, other energy providers, or some combination, underwrites these major energy investments as counterparties.

Text Box 2. Potential incentive levels related to decarbonization[53] [54] [55]

The cumulative cost metrics over a period of 30 years provided in this analysis are not directly comparable with annual upfront costs required at the customer level in the short term, since I) costs are spread over a longer period of time, and II) costs in this analysis are provided on a levelized basis. An analysis of *upfront* customer costs provides a more useful comparison with statewide energy efficiency budgets.

5 out of 8 pathways in this analysis reach 1 million electrically heated homes by 2030, through a combination of electric resistance heating, ASHPs, GSHP and Hybrid Heat Pumps. To illustrate, with annual average conversion of 80,000 homes per year* and estimated incremental heat pump costs of approximately $7,000 by home compared to a counterfactual, incremental residential customer costs are likely to exceed $0.5 billion per year, or $1.5 billion over a three-year period, for heat pumps alone. With building shell measures and in-kind efficiency replacements included, incremental customer costs towards 2030 are likely to exceed today's annual statewide energy efficiency budget.

The budget for the 2019-2021 statewide energy efficiency plan, which includes the Mass Save program, was $2.8 billion for the 2019-2021 period. The budget of the recently approved 2022-2024 statewide energy efficiency plan is approximately $4 billion for three years, showing an increase of nearly 30%. Approximately $1.1 billion of these funds are reserved for residential participant incentive for electric EE initiatives, and $0.7 billion for residential participant incentives for gas EE initiatives, or $0.6 billion combined annually.

**1 million homes by 2030 indicates 700,000 conversions compared to today, as approximately 300,000 homes in Massachusetts are electrically heated. This indicates approximately 80,000 conversions per year between 2022-2030.*

Constructability

All decarbonization pathways require an unprecedented level of energy sector construction to achieve the Massachusetts climate goals. Across pathways, there are several common characteristics and assumptions, including an extraordinary level of electric generation, transmission, and distribution construction at a scale far surpassing historical performance, the deployment of generation technologies at scales that are new to New England and/or pipeline infrastructure to support alternative energy delivery.

[53] Massachusetts Municipal Association (2019) State approves new three-year energy efficiency plan. https://www.mma.org/state-approves-new-three-year-energy-efficiency-plan/

[54] DPU Approves Massachusetts' Nation-Leading Three Year Energy Efficiency Plan: https://www.mass.gov/news/dpu-approves-massachusetts-nation-leading-three-year-energy-efficiency-plan#:~:text=BOSTON%20%E2%80%94%20The%20Massachusetts%20Department%20of,and%20the%20Cape%20Light%20Compact.&text=It%20is%20estimated%20that%20this,in%20benefits%20to%20the%20state.

[55] Program cost data in this illustration are taken from the 2022-2024 Statewide Data Tables (Gas and Electric): https://ma-eeac.org/plans-updates/

Given the fundamental importance of electric generation to all decarbonization pathways, the Consultants for this assessment principally focused on the overall ISO-NE generation capacity requirements, as outlined in Chapter 4. Those include the construction of electric power generation facilities approximately 2 to 3 times the current level in ISO-NE, which is unprecedented for the region. In addition to top-line capacity additions, the Consultants also considered the type of generation resources to be built and the implications for electric transmission costs.

Key findings and observations

In addition to the overall magnitude of generation capacity expansion required across pathways, there is a significant change in the type of technologies that are deployed as illustrated on Table 13, as depicted earlier on Figure 21 that shows total renewable buildouts over time.

Table 13. Installed generation capacity and T&D by type.

ISO-NE region	Aggregate 2050 Generation Capacity Additions by Type (GW)							Transmission Costs*	Distribution Costs*
	New CC/CT	Onshore Wind	Offshore Wind	Utility Solar	Dist. Solar	Storage	Imports	30-year CAGR	30-year CAGR
Reference	1	0	6	9	3	7	1	1%	1%
Low Electrification	13	1	19	22	5	11	3	2%	2%
High Electrification	24	1	25	22	5	12	3	3%	2%
Interim 2030 CECP	21	1	25	22	5	12	3	3%	2%
Hybrid Electrification	8	1	25	22	5	12	3	3%	2%
Networked Geothermal	8	1	21	22	5	11	3	2%	2%
Targeted Electrification	12	1	24	22	5	12	3	3%	2%
Efficient Gas	2	1	9	16	5	9	1	1%	1%
100% Gas Decommissioning	17	2	29	22	6	13	3	3%	2%

** Transmission and distribution cost CAGRs based on Massachusetts specific cost forecast, not ISO-NE*

Decarbonization pathways primarily rely on large-scale deployment of renewable generation technologies, such as wind and solar, which account for approximately 60% to 70% of capacity additions across all pathways. This represents a significant divergence from the current ISO-NE resource mix; specifically, of the 17 GW of capacity added in ISO-NE since 1995, approximately 14 GW (or 80%) was from natural gas-fired power plants, while wind and solar each added approximately 1.7 GW (or combined 20%).[56]

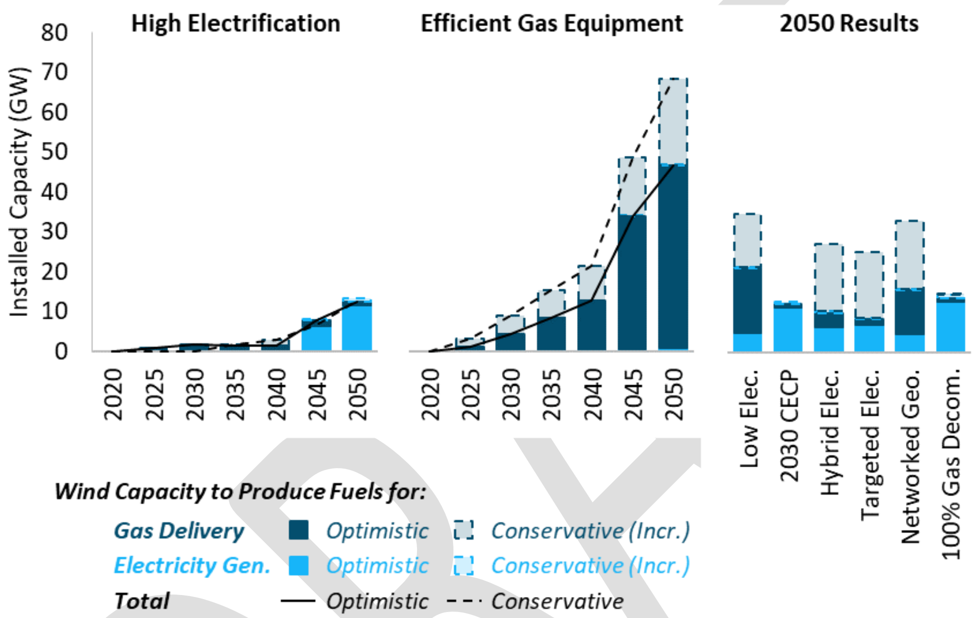
Given the scale of renewable buildouts modeled in this study, an important consideration is the availability and costs of transmission infrastructure required to integrate renewables and serve loads in New England. In this study, all renewable projects are assumed to incur 230 kV interconnection (spur line) costs, which connect the project sites to the bulk grid. Additional 345 kV network upgrade (backbone) costs are assumed to transfer renewable power on new interstate transmission lines to an assumed load center (Boston), once existing headroom on the transmission system is exhausted. Altogether, ISO-NE fixed transmission costs related to renewable generation interconnection and system upgrades are expected to grow at double the rate of a Reference pathway (1% vs. 2-3% CAGR) in all pathways except for Efficient Gas Equipment (1% CAGR). It should be noted that all pathways assume access to incremental Canadian hydropower requiring construction of transmission across the U.S. – Canada border, which to-

[56] https://www.iso-ne.com/about/key-stats/resource-mix/

date has proven difficult to permit and build.[57] More details on transmission headroom and cost assumptions are provided in Appendix 1.

Pathways also require construction activities to support production and delivery of alternative fuels, such as hydrogen. For example, the Efficient Gas Equipment pathway requires approximately 45–70 GW of renewable generation capacity outside of New England for hydrogen production (see Figure 33, with low- and high-end renewable capacity needs corresponding to optimistic and conservative views on renewable fuels, respectively) to supply hydrogen and synthetic natural gas production across sectors in New England, as well as dedicated pipelines to supply hydrogen to power generation and the industrial sector.

Figure 33. Installed renewable capacity outside of New England for synthetic fuel production for New England.[58]



Lastly, pathways that rely on networked geothermal systems (i.e., Networked Geothermal and 100% Gas Decommissioning) require rapid construction and conversion of customers to alternative heating services. These pathways assume peak adoption rates between 2025 and 2040, with approximately 200,000 residential and 15,000 non-residential customers converting to geothermal heating every 5-years. This type of infrastructure has not been deployed at such a significant scale in the Commonwealth or anywhere in the U.S. and may result in unique implementation challenges, especially given the need for decision and timing alignment across many individual customers.

Policy implications

Based on our research, analysis, and model results there are various policy implications of the significant construction requirements of the pathways, including:

[57] Northern Pass and the New England Clean Energy Connect are two examples of transmission projects that have faced permitting and siting challenges.

[58] Assuming hydrogen is produced by electrolysis co-located with wind power in all scenarios, using wind resource data from Pennsylvania. Fuel demand includes hydrogen (direct use) and synthetic methane (implied hydrogen demand). "Optimistic" and "Conservative" refer to optimistic and conservative views on decarbonized fuels, respectively (see details in Chapter 4).

- **Regulatory review and permitting.** To facilitate the unprecedented level of construction activity required within each pathway, there will need to be coordinated processes to permit, authorize, and construct infrastructure across numerous federal, state, and local agencies. Thus, regulatory activity and decisions are not limited to the purview of the Massachusetts D.P.U. but require much broader involvement from numerous jurisdictions. For example, any large transmission projects that cross state or international borders will require regional planning, coordination, and numerous approval stages.
- **Market changes.** In addition to the regulatory, siting, permitting, and financing requirements, there may be other policy implications associated with the significant build out and construction of electric infrastructure required by each pathway. Specifically, the construction of renewable generation, with no or low fuel costs, will likely change the dispatch curve and price signal of energy. Taken together these increases and changes in electric demand and supply will likely increase the variability of loads and supply, potentially increasing the market volatility for wholesale and retail prices.
- **Stakeholder engagement.** All pathways will require substantial investments in stakeholder engagement to educate the public regarding the project(s), incorporate feedback, and build energy infrastructure that balances divergent interests in a cost-effective manner. This is especially relevant for any construction activity that may impact environmental justice communities, as recent legislation mandates special protections and considerations for these groups and populations.

Reliability & Resilience

Definitions of reliability and resilience

Reliability is a formal term used in both the natural gas and electricity sectors to define the conditions under which a system has sufficient resources and delivery capacity to meet forecasted load requirements. The natural gas and electric systems are both designed, built, and planned to be reliable according to industry-specific standard metrics. As such, natural gas and electric planners use different planning standards when defining a reliable system.

- **Gas supply reliability planning** is currently conducted at the individual LDC level using established standards and approaches that are reviewed and approved by the Department.[59] In general, the LDCs use between 1-in-30 and 1-in-50 year planning standards that are based on the probability that the forecasted level of demand will occur. In other words, the gas supply portfolio is required to be sufficient to meet demand during extreme weather events (i.e., design day and design year) in compliance with the LDC filed and Department approved probability of occurrence (e.g., 1-in-30). Based on prior LDC planning and resource acquisition decisions coupled with the "end of pipeline location" of the service area,[60] the LDCs have developed a diverse portfolio of gas supply

[59] These LDC standards and procedures include developing and submitting every two years to the Department for approval a Forecast and Supply Plan ("F&SP") for the ensuing five-year period.

[60] Pipelines serving the New England region, in general, and the LDCs, in particular, are at the "end of the system" and are highly utilized by gas markets within the New England states. Specifically, since regional LDC load is winter peaking, pipeline capacity that is not utilized in the summer is used by natural gas-fired generators to meet electric load, which currently peaks in the summer, allowing the pipeline infrastructure to have higher annual utilization. The various customer segments on the upstream pipelines have different commercial and regulatory incentives regarding approaches to contracting for service. While LDCs typically contract for long-term, firm service, power generators have not typically contracted for long-term firm transportation on pipelines and have used capacity release or interruptible pipeline services for natural gas delivery; and large commercial and industrial customers may have multi-year delivered services with third parties.

resources, which include pipeline transportation, underground storage, and peaking resources to ensure reliable gas supply to their customers.

- **Electric system reliability planning** is currently conducted at both a regional and utility level. Electric supply planning is conducted primarily via the Independent System Operator of New England ("ISO-NE"). ISO-NE uses a "1-in-10" loss-of-load expectation reliability standard, meaning that loss-of-load due to generation resource shortfalls, whether due to extraordinary loads or generator outages, should not occur more than one day in 10 years. This is a common planning standard, and is used in many other jurisdictions, including in cold regions with high levels of electric heating such as Quebec and France, which use 1-in-10 year planning standards. This metric is translated into an equivalent target planning reserve margin, expressed as a percentage above median-year peak demand. Electric reliability is supported by a range of generation, transmission, and distribution assets across the region. Investments in electric delivery reliability occur at multiple jurisdictional levels, ranging from ISO-NE to individual electric utilities.
- Despite being described in similar "1-in-X" year terms, the electric and gas reliability planning standards are not directly comparable. Outages for electric and gas systems have markedly different impacts and restoration times. Insufficient electric supply generally results in rolling blackouts that typically last a matter of hours, although storms and other extreme events can lead to longer duration outages. In contrast, natural gas outage events are less frequent and often require LDCs to deploy staff to relight pilots and conduct other safety checks before service is restored. Given that this can take several days or longer if there is widespread loss-of-load, LDCs use a more conservative planning standard.[61]

Gas and electric delivery infrastructure have markedly different characteristics. The primary difference between these systems is that gas delivery infrastructure is largely underground, while a larger share of electric infrastructure is above-ground. Thus, electric systems are more likely to be affected by inclement weather and other disturbances to infrastructure.

It is important to note that while the gas and electric reliability planning currently happen in different regulatory contexts, the reliability of electric and gas systems are already intertwined to a significant extent. Most modern natural gas equipment requires electricity to operate, with the implication being that many customers lose gas heating services during electric outages today. Conversely, electricity systems today rely on gas facilities to maintain electric reliability. When gas supply is compromised, the electricity system could adversely be impacted.

Resilience, unlike reliability, is not formally defined in the energy sector today. One definition is an energy system that is resistant to disruptions and able to recover quickly after shocks and stresses, and "is generally characterized by high redundancy, functional diversity, adaptability, and modularity."[62] Other

[61] With respect to natural gas and electric distribution system reliability, as noted in a Gas Technology Institute study released in July 2018, "…natural gas and electric distribution service are both reliable in an absolute sense, with superior attributes for natural gas distribution systems. Table 1 and Figure 2 provide a summary of the results related to: 1) reliability and availability of these energy services to homes and businesses and (2) the frequency or likelihood of outages per year. Natural gas distribution systems operate at very high levels of service reliability." Gas Technology Institute, Assessment of Natural Gas and Electric Distribution Service Reliability, July 19, 2018, at 1.

[62] Jasiūnas, Justinas, Lund, P., & Mikkola, J., "Energy system resilience – A review", *Renewable and Sustainable Energy Reviews,* Volume 150 (2021).

definitions of resilience take a broader approach, often tying resilience to energy security, and may include technical, political, social, and market factors within the definition. [63]

Given these complexities, the Consultants do not attempt to rank or categorize resilience across the decarbonization pathways evaluated in this Report. Indeed, the resilience of a given decarbonization pathway will depend on *what types* of disruptions or shocks are evaluated. For example, scenarios with high levels of electrification (i.e. High Electrification, Interim 2030 CECP, 100% Gas Decommissioning) are likely to be more resilient against the possibility of biofuel and hydrogen supply chain disruptions or price shocks, while the Efficient Gas scenario and Low Electrification scenarios are likely to be more resilient against the impacts of electrical outages resulting from storms or other shocks to the electric grid.

Discussion of gas system reliability and planning and policy implications

Under all decarbonization scenarios, the LDCs' load curves will experience significant changes to both the level of demand and the shape of that demand, the degree of which varies considerably across scenarios as shown in Chapter 4. Changes in the total volumes and patterns of natural gas demand will have implications for:

- **Resource supply portfolio**
    - The LDCs' gas supply portfolios would need adjusting, where possible, to align with the revised demand curve (e.g., demand increases or reductions). Any resource portfolio change will also need to consider the contract terms and conditions of the various resources in the existing portfolio as the timing of resource contractual decisions may not align with the timing of the changes to the demand curve.
    - The Department's standards for evaluating gas supply plans, which currently includes a review of adequacy, reliability, and cost minimization, may need to be revised. Adjustments to the LDCs' gas supply plans because of load curve changes driven by electrification, will likely have various cost implications, which will need to be reviewed by the Department relative to adequacy and reliability considerations. In addition, the standards may need to be expanded to include other factors, such as environmental impacts, resource flexibility, and contract renewal and termination rights.
    - Finally, the forecast period associated with the LDC's Forecast and Supply Plan may need to be expanded to allow for longer-term planning (i.e., beyond the current five-year period).
- **Performance of gas infrastructure**
    - Changes in the level and shape of the demand curve may also impact the operating performance of gas infrastructure, which is designed and operated to serve the LDCs' current load profile.
    - This analysis does not attempt to model the operations and performance of gas infrastructure under each of the decarbonization scenarios, as the analysis does not include a geographic representation of where electrification or targeted gas decommissioning would occur within the Commonwealth. However, to the extent that specific decarbonization projects are planned in the future, the LDCs would need to perform detailed gas hydraulic analysis for specific gas pipelines, to ensure that safe and reliable gas service is not compromised for remaining customers if targeted electrification

[63] Jesse, BJ., Heinrichs, H. & Kuckshinrichs, W. "Adapting the theory of resilience to energy systems: a review and outlook," *Energ Sustain Soc* **9,** 27 (2019).

  - or networked geothermal projects are implemented as part of a strategic gas decommissioning effort.
- **Upstream pipeline service**
  - Decreases in LDC load may also lead to changes in upstream contracting practices, which may impact services offered, rates, and terms and conditions of service provided by the upstream pipeline and storage asset owners (e.g., contract duration or renewal rights).
  - As LDCs de-contract or reduce their upstream pipeline commitments to reflect reduced gas demand, the cost-of-service associated with upstream providers also will be allocated to remaining shippers (e.g., other LDCs or municipal utilities, power generators, large commercial and industrial customers) thus increasing costs to these shippers.
  - LDC gas supply portfolio costs may have more variability given: (i) the inherent difficulty to modify or change a gas supply portfolio to meet demand that is expected to decline at an unknown rate (e.g., changes in demand may not align with pipeline contract termination dates); and (ii) the likely changes in costs associated with upstream resources.

Discussion of electric system reliability and policy implications

All of the decarbonization scenarios evaluated in this study have been modeled to achieve current electric reliability standards for the ISO-NE region, accounting for increased electric demand from electrification as well as increased reliance on variable renewable electricity to decarbonize the grid. However, it is worth noting that these 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. This increased reliance on electricity for energy services across all sectors may have implications for electric system reliability planning in the future, including:

- **Determinants and resource contributions towards resource adequacy**, particularly under extreme winter weather conditions, to reliably meet the increased reliance on electricity for space heating and transportation. To the extent that current ISO-NE electric reliability standards were not designed with significant levels of electric space heating or electric transportation in mind, the ISO-NE may need to consider whether any changes to electric reliability standards are required, as the region experiences higher reliance on electricity demand. More stringent electric reliability standards would likely increase the relative costs of scenarios with high levels of electrification.
- **Generator fuel/energy supply availability and adequacy** will need to be reviewed and evaluated to ensure that Forced Outage rates (i.e., probability of generator failure) reflect risks under extreme winter weather conditions and at the reduction of fuel supply diversity. In addition, generator fuel or energy supply availability may need to be reviewed and evaluated to ensure the risk of energy supply curtailments or disruptions are evaluated under extreme winter weather conditions, similar to the LDCs' supply planning.
- **Critical facility/on-site reliability** may need to be considered. In scenarios that significantly reduce or eliminate natural gas, such as 100% Gas Decommissioning, secondary energy sources or energy storage will be needed to maintain local reliability standards at critical facilities (e.g., emergency stand-by power requirements for particularly sensitive areas in hospitals, such as operating rooms and critical care units[64]). Likewise, distributed energy generation and storage may become more

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[64] Federal Emergency Management Agency (FEMA) and the U.S. Department of Health and Human Services Office of the Assistant Secretary for Preparedness and Response, "Healthcare Facilities and Power Outages: Guidance for State, Local, Tribal, Territorial and Private Sector Partners," August 2019, available at: https://www.fema.gov/sites/default/files/2020-07/healthcare-facilities-and-power-outages.pdf

attractive to all customers as a higher reliance on electricity for transportation and space heating increases the necessity of reliable electric supply.

Feasibility implications regarding reliability & resilience

All the decarbonization pathways indicate an increased reliance on electricity for transportation services, space heating, and other end uses. This means that electric reliability will play an increasingly important role in Massachusetts' economy across all scenarios evaluated, but especially so in scenarios that electrify both transportation and heating.

Furthermore, these scenarios implicate a greater reliance on *regional* electricity planning and regulation at the ISO-NE, relative to gas reliability planning and regulation at the Department. The Consultants note that electric reliability planning standards may need to be updated over time to reflect changes in electric demand and supply. The pace and scale of these changes are most extreme for the scenarios with higher levels of electrification.

All scenarios are meant to reflect the infrastructure requirements and costs associated with current *electric reliability* standards, and as a result, we do not model differences in system-wide electric reliability across the scenarios. Importantly, this analysis does not perform a detailed transmission or distribution reliability analysis that reflects the increased role of the electric sector in providing both transportation energy and space heating across the state. The cost and feasibility of electrical distribution upgrades, and deployment of distributed energy storage or other back-up generation for electric reliability within dense urban areas, such as Boston, represents an important source of uncertainty in this study.

Finally, as Massachusetts transitions to a clean energy future, the *resilience* of the energy system to changing patterns of energy demand, energy supply, and a changing climate, in the form of more severe storms and other weather events, will become increasingly important. While resiliency overall is difficult to quantify, and not rigorously defined within industry standards, existing gas infrastructure could be strategically used to support energy system resilience, for example, by providing renewable fuels for back-up generation and space heating during periods of critical peak demand.

Technology Readiness

The decarbonization pathways analyzed in this Report rely on technologies with varying levels of "readiness", referring to the level of maturity and commercialization of these technologies. In this Report, The Consultants make use of a "Technology Readiness Level" scale ranging from 1-11 developed by the International Energy Agency.[65] Generally, portfolios of decarbonization options that rely on lower TRL measures carry additional risk, as these technologies need substantial development before reaching full maturity.[66]

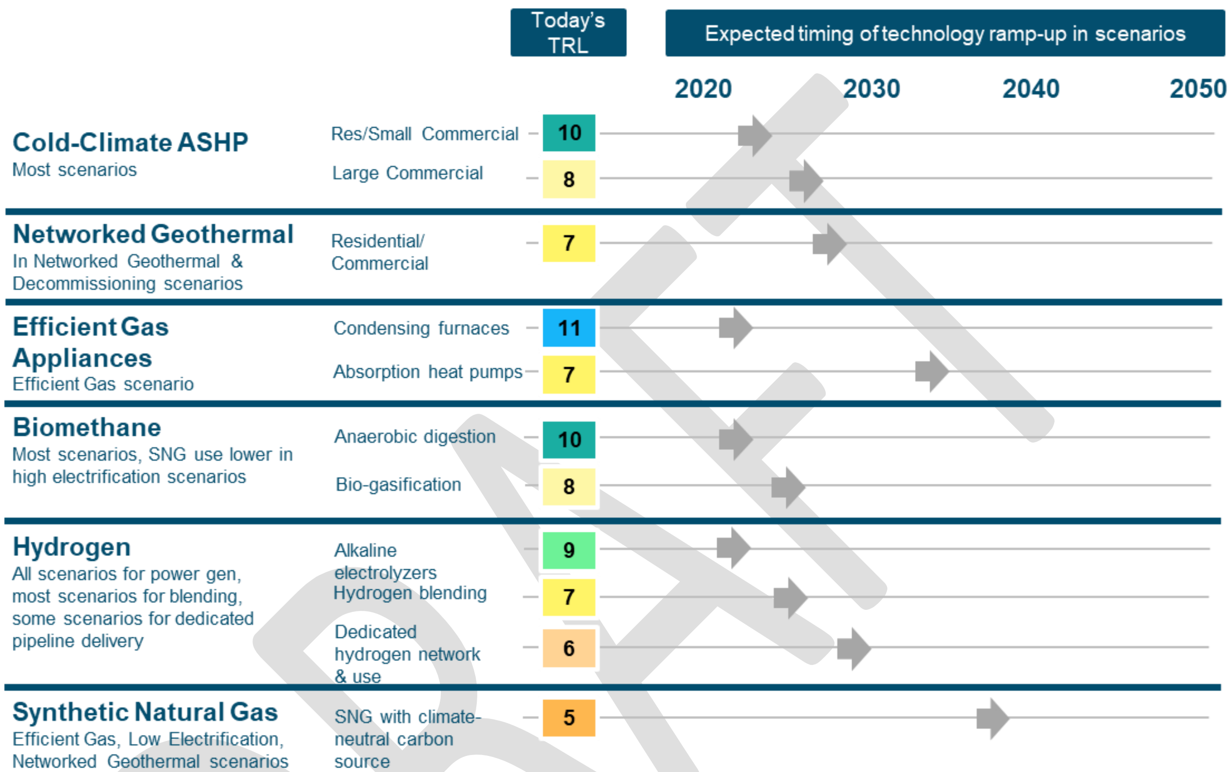
[65] https://www.iea.org/articles/etp-clean-energy-technology-guide. This scale indicates how a technology with a TRL of 11 is fully mature and ready to scale, whereas TRL's lower on the scale need additional R&D and/or commercialization support. For an indication of today's TRL, the Consultants mostly aligned with the International Energy Agency's assessment of technologies, complemented with the Consultant's judgement for those technologies not assessed by the IEA.

[66] In developing decarbonization pathways, E3 and other deep decarbonization researchers generally screen out technologies that are low (<5) on the TRL scale, because of their speculative nature and the short time horizon of mid-century climate goals. Therefore, the decarbonization pathways analyzed for this work only include technologies with a TRL of 5 and higher.

Key findings and observations

The Consultants developed an assessment of the TRL of key technologies that are used to decarbonize gas end-uses in economy-wide scenarios. Figure 34 shows the current TRL of key technologies today and the approximate timing for when each technology begins to be deployed at scale within the scenarios.

Figure 34: Technology readiness levels by key decarbonization measures and the timing of their deployment in scenarios.



Several observations can be made from this figure:

- Demand-side technologies like condensing gas furnaces or residential cold-climate ASHPs are utilized in the short term across scenarios. These technologies are fully commercialized and have already been deployed across New England and elsewhere in the United States. As a result, there is effectively no risk that these technologies will not be available to contribute to decarbonization.
- Other demand-side transformations, such as electrification retrofits in very large buildings or gas absorption heat pumps, are less commercially mature and therefore carry a degree of risk. These technologies are deployed later in time in the decarbonization pathways, but still carry the risk of not being available at scale in time.
- Options to decarbonize gas supply carry lower TRLs and are generally deployed later in time as a result. While producing biogas via anaerobic digestion is a relatively mature technology, options including bio-gasification, hydrogen blending into gas distribution systems and synthetic natural gas do not have the same track record. Over-reliance on these options raises the risk that some may not develop, or not come down in cost, as expected. In addition, there is limited experience

blending hydrogen into gas distribution systems, which may require modified operations and safety practices.[67]

Policy implications

Policy implications with regard to TRLs mostly exist with regard to the need for Research and Development and further commercialization of decarbonization technologies. These R&D needs are further described in Chapter 6.

Air Quality

A quantitative analysis of the air quality impacts of decarbonization scenarios is beyond the scope of this analysis. However, drawing from principles of combustion and existing literature, it is possible to offer a directional assessment of how the scenarios may compare across air quality impacts. In this analysis, the Consultants' reviewed the impact of pathways on air quality through the lens of combustion of fuels, assuming a reduction in combustion of fuels over time leads to improvements in air quality and therefore provides health benefits, and vice versa. The Consultants note that the Roadmap's Economic & Health Impacts Report provided a detailed assessment of the effects of decarbonization on air quality in the Commonwealth and refer the reader there.[68]

Key findings and observations

Combustion of fuels produces emissions of pollutants like PM 2.5 and NOx, which lead to deleterious health impacts, often concentrated in environmental justice communities. All scenarios substantially reduce the amount of combustion that occurs in the Commonwealth, as shown on Figure 35. This figure indicates that the reduction in combustible fuels is most prominent in pathways with high levels of electrification. The highest level of combustion remains in the Efficient Gas Equipment pathway, that keeps higher levels of gaseous fuels in the energy mix compared to the other pathways.

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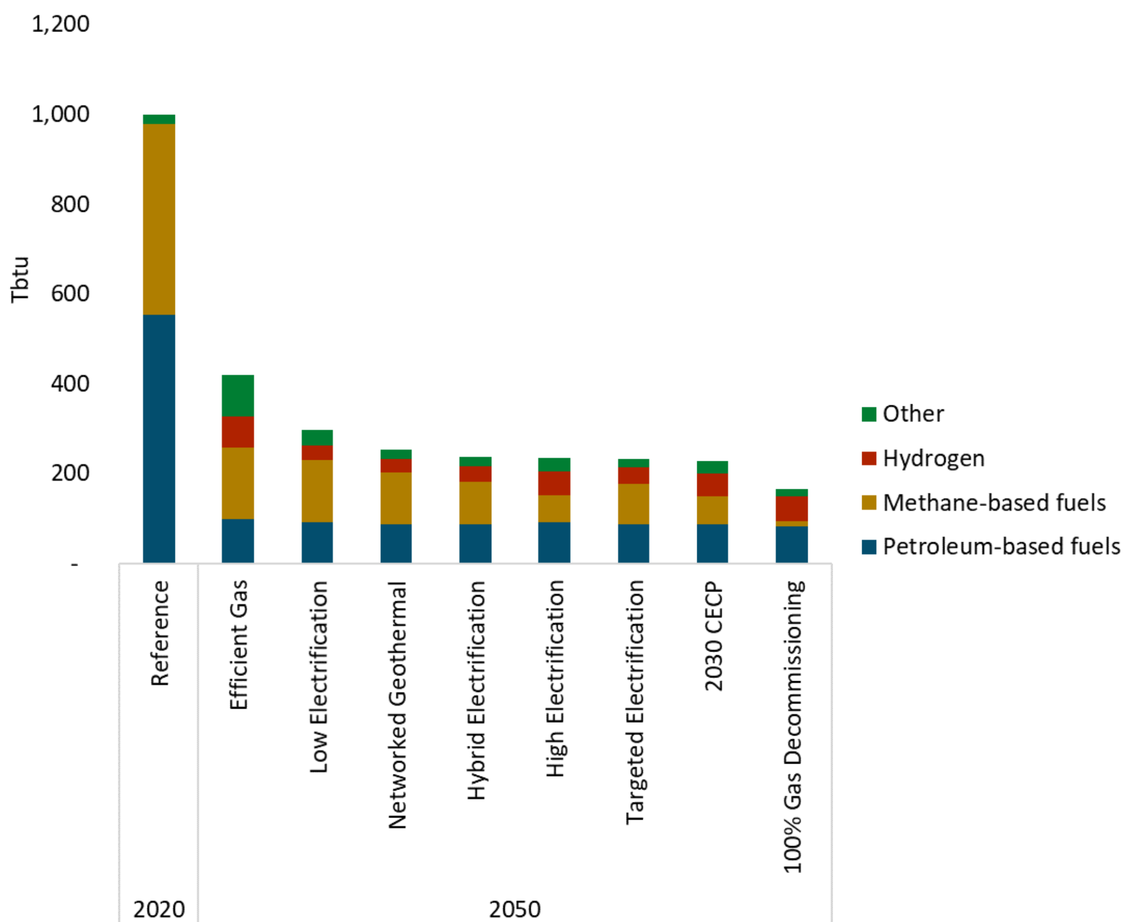
67 See, for instance, Melania et al 2013. "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues." https://www.nrel.gov/docs/fy13osti/51995.pdf

[68] The Roadmap estimated that *"achieving net zero by 2050 would lead to a reduction in cardiac and respiratory illness that would result in the avoidance of 400 deaths and 25,000 days of missed work annually.* Massachusetts 2050 Decarbonization Roadmap, page 26.

Figure 35. Level of fuel combustion across pathways, 2020 versus 2050. Figure includes combustion from transportation, buildings & industry.



Scenarios mostly differ in the amount and type of combustion that occurs related to heating:

- Scenarios with high levels of electrification (High Electrification, Interim 2030 CECP, 100% Gas Decommissioning), and scenarios where networked geothermal systems are deployed nearly eliminate combustion from the direct-use of gaseous and liquid fuels to heat buildings. These scenarios do, however, require more firm capacity to maintain a reliable electric system. In the scenario modeling, gas turbines were assumed to provide that firm capacity, transitioning from being fueled by natural gas to hydrogen over time. While these facilities operate infrequently, this approach to reliability could increase the number of communities affected by pollution from power generation. Importantly, other forms of firm capacity with lower or no combustion may become available over the coming decades.
- Scenarios that rely on hybrid electrification also see steep declines in the combustion of fuels in buildings, though not to the same extent as in all-electric cases. However, higher combustion in buildings is counterbalanced by lower firm capacity requirements, decreasing the potential for emissions associated with maintaining electric reliability.

- The Efficient Gas Equipment scenario sees decreased combustion due to energy efficiency measures, but gas continues to be used throughout the year in most buildings. Remaining combustion emissions could potentially be mitigated via technologies like low-NOx furnaces.

Several studies have identified large health benefits from reduced combustion in deep decarbonization scenarios. The Roadmap identified that reducing GHG emissions would result in annual health savings of between $2B to $4.5B relative to today, including high levels of health benefits in EJ communities. Recent work released by NYSERDA identify a benefit that ranges from $50 to $120 billion between 2020 and 2050 from improvements in air quality[69]. Highly detailed modeling of air quality impacts and human exposure in California have produced substantially higher estimates of benefits, with over $100 billion in annual health savings expected by 2050.[70]

Policy implications

Policies aimed at reducing the level of fuel combustion and improving air quality span across sectors and many have already been implemented and proposed in Massachusetts. For instance, Massachusetts has set regulations to match California's Advanced Clean Cars (ACC) Program, will pursue the development and implementation of a regional Low Carbon Fuel Standard (LCFS) designed to reduce the carbon intensity of transportation fuels by 2030 and has established regulations that tighten the emissions limit of in-state electric generators.[71] In the Building sector, the Commonwealth is investigating ways to establish an emission cap on heating fuels that may result in air quality benefits. Further policies that would improve air quality in the Commonwealth are closely tied to the policies required to stimulate building electrification, as discussed in other sections of this Report.

Workforce Development

Decarbonization pathways have significant implications for the LDC workforce, as well as overall Massachusetts and regional labor requirements. A quantitative assessment of potential LDC workforce changes and implications resulting from decarbonization policies is not within the scope of this Consultant Report, nor is an assessment of broader labor requirements needed to support decarbonization strategies and tactics. However, certain model outputs can be used to gauge the direction and magnitude of potential workforce changes.[72]

Key findings and observations

Table 14 shows forecasted LDC operations and maintenance (O&M) expense across decarbonization pathways.

[69] New York State Climate Action Council. *Draft Scoping Plan*. December 30, 2021. https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scoping-Plan.ashx. Accessed January 8, 2021.

[70] Electric Power Research Institute 2019. *Air Quality Implications of an Energy Scenario for California Using High Levels of Electrification.* https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-049.pdf Accessed January 8, 2021.

[71] Interim 2030 CECP – December 2020 version.

[72] The Consultants focused on two primary metrics from the revenue requirements models, namely LDC operations and maintenance (O&M) expense – to serve as a proxy for LDC workforce changes[72], and growth in forecasted electric distribution revenue requirements (shown as a 30-year CAGR) – to serve as a proxy for electric distribution industry workforce changes.

Table 14. Forecasted total LDC O&M expense.

2020 dollars (millions)	2020	2025	2030	2035	2040	2045	2050	Total Change	Percent Change	30-year CAGR
Reference	883	916	973	1,023	1,059	1,080	1,091	207	23%	1%
Low Electrification	883	914	928	899	852	791	746	(138)	-16%	-1%
High Electrification	883	912	888	792	674	550	471	(412)	-47%	-2%
Interim 2030 CECP	883	871	796	682	576	486	443	(440)	-50%	-2%
Hybrid Electrification	883	891	906	920	931	938	941	57	6%	0%
Networked Geothermal	883	886	839	791	748	711	691	(192)	-22%	-1%
Targeted Electrification	883	886	839	791	748	711	691	(192)	-22%	-1%
Efficient Gas	883	913	965	1,016	1,053	1,077	1,090	207	23%	1%
100% Gas Decommissioning	883	886	767	641	534	457	433	(450)	-51%	-2%

Assuming there is a correlation between LDC O&M costs changes and number of customers[73], then scenarios that project a dramatically reduced level of natural gas customers imply a long-term reduction in LDC workforce.[74] On the other hand, pathways with continued long-term utilization of the natural gas distribution systems require continued or growing LDC O&M spending, thus implying a steady-state or an expansion of the LDC workforce. Under certain pathways, there may be other unique challenges to the LDC workforce based on the type of alternative energy delivery infrastructure assumed in the particular pathway, for instance in the Networked Geothermal pathway. As another example, in Targeted Electrification and 100% Gas Decommissioning, the labor requirements to decommission portions of the LDC system may require a temporary expansion of the LDC workforce[75].

Decarbonization pathways also have implications for the electric sector. Focusing on the electric distribution revenue requirements metric, and as shown earlier, there is significant growth in electric distribution revenue requirements which implies an increase in the electric industry labor force to support electrification efforts. Pathways with the most dramatic rates of change in electric distribution revenue requirements (i.e., the High Electrification, Interim 2030 CECP, and 100% Gas Decommissioning scenarios) may have more immediate incremental labor requirement to support electrification efforts, earlier in the analysis period.

Regardless of pathway, there are common challenges with respect to Workforce Development, including:

- Retaining knowledge and experience within LDCs – it is critical to retain, augment, and support the LDC workforce to ensure continued safe and reliable natural gas system operations in all pathways, including those with decreasing utilization. This may prove more challenging in

[73] Due to the lack of available industry data associated with LDC employment changes resulting from federal or state carbon policies, there are two sensitivities modeled with respect to LDC O&M cost changes. Specifically, in one sensitivity, the Consultants assumed that changes in LDC O&M costs are correlated to changes in customer count and natural gas throughput. However, it is possible that given the capital-intensive nature of LDCs, as well as the on-going need to perform safety and reliability activities regardless of customer count, there could be minimal or no correlation between forecasted natural gas customer reductions and LDC O&M costs (i.e., the second sensitivity). In this sensitivity, changes in LDC O&M costs are not correlated with changes in gas distribution system utilization, and therefore, LDC O&M costs remain flat after customer count peaks in each scenario. Thus, even though natural gas customer counts decline dramatically in certain scenarios (e.g., approximately 1.5 million customer migrations in High Electrification, Interim 2030 CECP, and 100% Gas Decommissioning) the LDC O&M costs are largely fixed and do not change in real dollar terms over the remainder of the 30-year period.

[74] Although these scenarios may still have increased short-term labor demands to support near-term natural gas customer additions.

[75] Oliphant, Elizabeth. *Electrification Impact Assessment: A Preliminary Analysis of the Utility Costs & Staffing Impact to Electrify All Single-Family Residences in Palo Alto*. https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/agendas-minutes/utilities-advisory-commission/archived-agenda-and-minutes/agendas-and-minutes-2020/11-04-2020-special/id-11639-item-no-3.pdf. Accessed January 8, 2021.

pathways with rapid and dramatic overall declines in natural gas customer count and throughput, as the magnitude and pace of decline in gas system utilization may have immediate and long-term impacts on the LDC business models and therefore consequences for the LDC workforce.

- Develop and expand broader decarbonization workforce – all pathways include substantial construction requirements associated with electric industry infrastructure, energy efficiency, and other energy delivery technologies, which will result in increased demand for labor to support these sectors. This overall expansion of the labor force may provide opportunities to retrain and transition the LDC workforce to the support these new or existing energy infrastructure sectors.
- Lead time for transition – the pace and magnitude of changes to the LDC business model (e.g., rapid migration of customers to electricity; significant reductions in volume and revenue) will impact the lead time and the ability of the LDCs and the state to develop, submit for regulatory approval, and implement workforce transition planning. Pathways with more limited or moderate electrification may allow for more lead time to address and support not only LDC operations but also staff the opportunities provided by the increase in the electric industry infrastructure and alternative energy technology fields.

Policy implications

Based on our research, analysis, and model results there are various policy implications associated with the significant workforce requirements and implications of the pathways, including:

- **Expansion of workforce policies identified in Massachusetts Senate Bill No. 9** *An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy*. Recent Massachusetts climate legislation prioritized and identified the need for workforce assistance to help facilitate an equitable energy transition, which includes support for fossil fuel industry workers.[76] Pathways with aggressive electrification of buildings may necessitate expansion of these programs to further encourage employee transitions from other sectors to the electric industry and education investments to encourage new workforce entrants to seek employment in the energy sector. Pathways with more moderate natural gas customer or pathways with gas customer growth may enable a more managed, structured, and timed workforce attrition strategies and policies.
- **Pace of policy change** - Pathways such as High Electrification, Interim 2030 CECP and 100% Gas Decommissioning include a more rapid and greater overall level of gas customer migrations, which likely implies more immediate disruption to the LDC workforce. Thus, LDC workforce policies will need to change at a faster pace and may require more regulatory intervention for scenarios that rely more heavily on electrification. For example, LDCs may need a rate tracker or other cost recovery mechanism to collect incremental expenses associated with workforce transition and retraining.

Customer Practicality

Each decarbonization pathway has unique and substantial implications for Massachusetts natural gas customers and the level of retrofits required across the Commonwealth's building stock. In order for decarbonization goals to be met, nearly every LDC customer will need to take action to retrofit their homes and businesses. Although there are numerous model outputs that could frame Customer Practicality, the most informative metric regarding overall direction, magnitude, and pace of customer

[76] Massachusetts Senate Bill No. 9 An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy. https://malegislature.gov/bills/192/S9

change is the difference in the number of natural gas customers by pathway over the 30-year analysis period to illustrate the level of customers migrating to alternative heating technologies. This dynamic is visualized earlier in the Report in Figure 25.

Key findings and observations

Table 15 provides a summary of total number of residential homes with heat pumps or electric heating by 5-year intervals for each pathway. As illustrated, most pathways involve some level of electrification of space heating applications (i.e., conversion from natural gas heating to an electric heat pump or alternative technology), which is a significant departure from today.[77] Pathways such as the Interim 2030 CECP and Hybrid Electrification reach 1 million electrically heated homes by 2030, requiring average sales levels of approximately 80,000 heat pumps by year between the period 2022-2030 (with sales levels ramping up towards 2030). Pathways that involve targeted electrification to avoid potential gas system replacements (i.e. Targeted Electrification and 100% Decommissioning) illustrate higher levels of conversions as electrification programs are accelerated to align with the GSEP program. In addition, most scenarios assume initiatives to implement building shell retrofits across a substantial share of the state's building stock.

Table 15. Number of residential homes with heat pumps or electric heating by pathway (includes hybrid heat pumps, networked geothermal systems and gas heat pumps).

in millions	2020	2025	2030	2035	2040	2045	2050
High Electrification	0.3	0.3	0.6	1.2	1.8	2.5	2.9
Low Electrification	0.3	0.3	0.5	0.9	1.3	1.7	2.0
Interim 2030 CECP	0.3	0.5	1.0	1.7	2.3	2.7	3.0
Hybrid Electrification	0.3	0.5	1.0	1.7	2.2	2.6	2.9
Networked Geothermal	0.3	0.4	0.9	1.4	1.8	2.2	2.3
Targeted Electrification	0.3	0.5	1.1	1.7	2.2	2.7	2.9
Efficient Gas	0.3	0.3	0.4	0.6	1.0	1.4	1.8
100% Gas Decommissioning	0.3	0.4	1.1	1.9	2.5	2.9	3.1

Pathways that require aggressive building electrification will likely need to depend not only on robust incentive programs for customer conversions but also on explicit limitations on natural gas, fuel oil, and propane as fuel choices for customers. The remaining pathways either provide continued choice of natural gas as a fuel for almost all existing and some new customers or allow some percentage of the existing natural gas customer base to retain natural gas as fuel. These pathways provide more time for incentive programs regarding customer conversions to be developed, implemented, and revised based on market feedback; limitations and mandates on customer fuel choices may still be required in these pathways but such policies do not have to be invoked as soon as in the high electrification pathways.

There is also a neighborhood-scale dynamic that is prevalent in certain pathways; specifically, in the 100% Gas Decommissioning, Networked Geothermal, and Targeted Electrification pathways, there is a need for groups of collocated customers to convert from natural gas to electricity or some other alternative energy technology such as networked geothermal. This group dynamic with respect to customer fuel choice is a novel and untested approach to customer conversions in the state.

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[77] According to 2019 MassSave data, fewer than 4,000 heat pumps had been installed in Massachusetts in 2019. According to the Boston Globe (August 2021), up to 1,000 of installations are whole home retrofits. The majority of today's electric space heating systems in Massachusetts are based on electric resistance heating.

Regardless of pathway, the significant changes facing customers will require a focused and tailored communication outreach and program development for environmental justice communities, low-income customers, and landlords/tenants to address challenges and hurdles unique to these customer groups. Specifically, any successful decarbonization strategy will need to address various challenges with respect to Customer Practicality, including:

- Pace of technology adoption – pathways with high levels of electrification (i.e. Interim 2030 CECP, High Electrification, Hybrid Electrification, Targeted Electrification, Networked Geothermal, 100% Gas Decommissioning) have significant levels of adoption of decarbonization technologies in order for the levels of adoption envisioned to be realized. LDCs and the state will not only need to provide sufficient incentives as discussed above, but also consumer education and protections. In addition, LDCs and the state may need to identify and support qualified contractors to encourage and facilitate adoption of these alternative technologies by customers, particularly those in EJ communities or low-income customers.
- Lead time for implementation – certain pathways require almost immediate customer action and decisions with respect to electrification. This is especially true for pathways that reach 1 million electrically heated homes by 2030 (Interim 2030 CECP, High Electrification, Hybrid Electrification, Targeted Electrification, Networked Geothermal, 100% Gas Decommissioning). Other pathways, such as Efficient Gas Equipment and Low Electrification, provide more lead time for program development, customer outreach, testing or piloting of technologies, and planned and structured regulatory engagement. Pathways that require a faster pace for electrification will require more immediate actions by LDCs and regulators to develop, review, approve, and implement decarbonization programs thus increasing the immediate need for utility, regulatory, and commercial resources.
- Customer decision-making, acceptance, and choice – To achieve the required levels of customer conversions, particularly those required in the high electrification scenarios, will require: (i) LDC or state sponsored programs that shift consumer economics in favor of electric technologies via incentives or higher gas commodity costs that reflect GHG externalities or compliance costs; (ii) LDCs or the state may need to impose mandates precluding natural gas as a fuel choice if incentives cannot provide enough impetus for customers to convert to electricity; and/or (iii) some combination of incentive, pricing and mandates, the timing of which will depend on the various pathways. Also, LDC incentive programs will need to address the needs of EJ communities and low-income customers such that electrification opportunities are available to all customers.

Policy implications

Based on our research, analysis, and model results there are certain policy implications, including:

- **Achieving Scale via Financial Incentives vs. Mandates.** The magnitude and pace of natural gas customer conversions and retrofits depicted in all pathways will likely require incremental policy changes to incentivize customers to select alternative energy solutions. However, incentives alone are unlikely to be sufficient to facilitate the level of change envisioned in the most aggressive building electrification pathways or pathways that require group decision making. Therefore, to achieve the customer conversions required by these pathways may require policies that explicitly ban or preclude natural gas, fuel oil, and propane as customer fuel options for end use applications such as space heating.
- **Consumer Protections.** Policy changes to ensure customer protections, particularly for low-income and small-business customers, will be needed in situations where a portion of the natural

gas network that is actively serving customers is proposed to be taken out of service. For example, defined conditions for when a customer does or does not have the right to 'opt-out' of a proposed project to decommission a neighborhood or street, as well as compensation for any loss of investment in existing equipment, costs of any relocation expenses during the conversion, or forgone business activity during the conversion.

- **EJ Communities and Low-income Customers.** Any initiatives to facilitate the transition of building heating, should engage affected communities in decision-making from the earliest possible stages. For example, affected communities should have a central role in identification and scoping of any targeted electrification or networked geothermal initiatives.

Customer Affordability

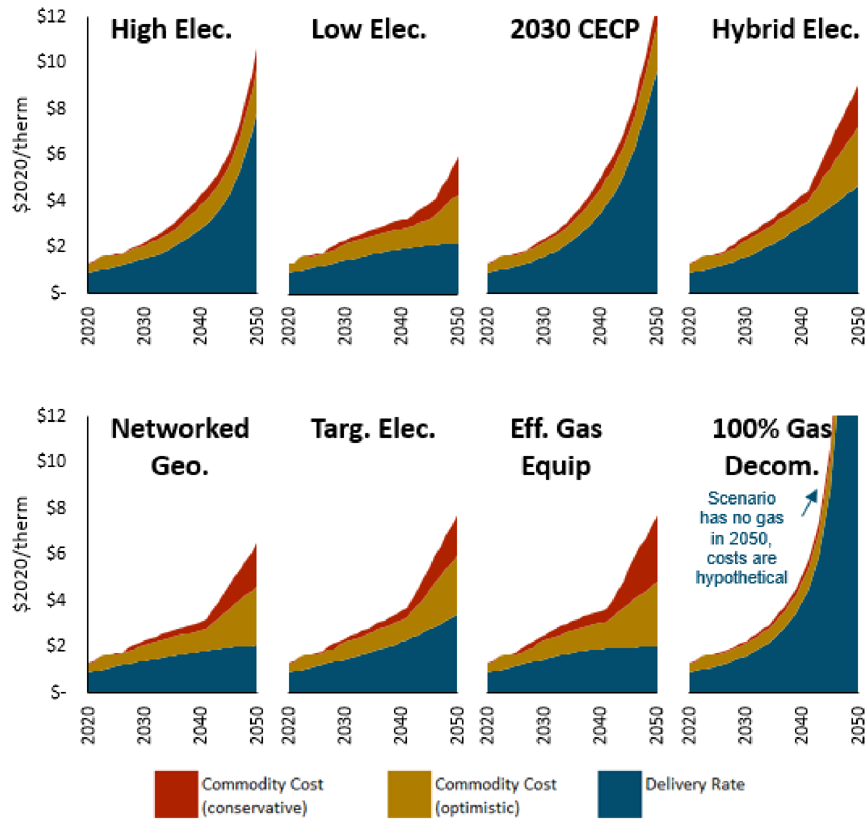
Affordability across pathways in this analysis is evaluated based on energy bill costs per customer, upfront capital cost requirements and energy costs relative to income. A detailed description on the methodology of customer affordability is provided in Appendix 1. It is important to note that this section considers impact of decarbonization on customer bills under the current regulatory framework. This means for instance that rates are determined based on current rate structures. Part II of the Report describes how potential negative customer impacts can be mitigated through a set of proposed regulatory initiatives.

Key findings and observations

To assess the impact of decarbonization pathways on customer affordability, the Consultants first evaluated the effect of decarbonization pathways on gas and electric utility rates.[78] Figure 36 provides the volumetric gas rate forecast developed for each pathway assuming no change in regulatory framework, broken out into commodity and delivery costs.

[78] On the electric side, volumetric rates are determined based on an estimation of Massachusetts Revenue Requirement on the electric system, taking into account load increases and allocation across customer classes as described in Appendix 1. On the gas side, the volumetric rate is comprised of delivery costs, or the $/therm required to recover an LDC's revenue requirement, and commodity costs, or the cost of procuring a therm of natural gas on behalf of a customer.

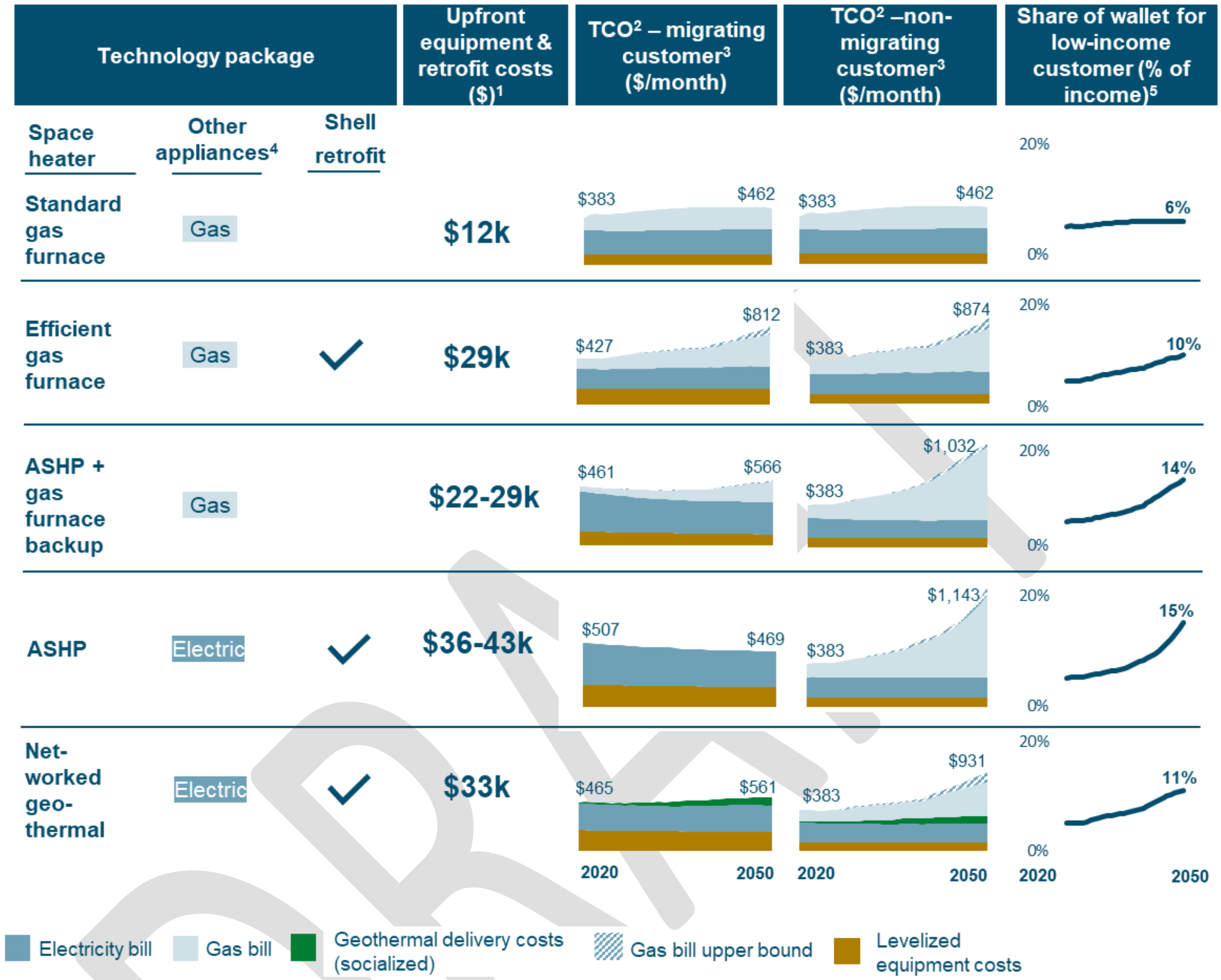
Figure 36. Volumetric residential rates including delivery costs and commodity costs ($/therm).



This figure shows how absent regulatory changes, all pathways would see volumetric rate increases, posing affordability challenges to customers that retain gas service within each scenario. Cost increases are most prominent for those scenarios that see a significant decline in gas customers and/or throughput, because the cost of maintaining the gas system is recovered over fewer customers and/or therms. In addition, scenarios with continuous use of gas for heating purposes, including Low Electrification and Efficient Gas Equipment, see a significant increase in the commodity cost component of volumetric rates.

Across all scenarios, non-migrating customers face higher monthly energy costs than customers that adopt a decarbonization technology package. The difference between a migrating and a non-migrating customer's energy burden varies between scenarios due to differences in technology packages and rates. Figure 37 shows an overview of customer affordability metrics for an average single family residential customer, looking at a set of decarbonization "technology package" that are most common to the decarbonization pathways. The figure shows both total cost of ownership (including energy bills and levelized equipment costs) for a customer that adopts the decarbonization technology ("migrating customer") and the total cost of ownership for a customer that does not adopt the technology package ("non-migrating customer"). In addition, the figures show the share of wallet for low-income, non-migrating customers, which represents the percentage a low-income customer would spend on energy bills relative to their income.

Figure 37. Overview of customer costs for an average, pre-1940 single family home. Gas bills are based on Eversource (NSTAR) rates.



¹ Includes cost of building shell upgrade (if applicable), space heating equipment, water heating equipment and cooking & clothes drying appliances.

² TCO = Total Cost of Ownership. Includes both energy bills and levelized cost of equipment.

³ A "migrating" customer is a customer adopting the technology package. A "non-migrating" customer is a customer not adopting the technology package. The charts include rates for the scenario shown in *italics*.

⁴ 'Other appliances' include: water heater, clothes dryer, and cooking. Chart does not include transportation electrification bills.

⁵ Charts show energy bill effects for low—income, non-migrating customers. A low income customer is defined as a customer with an income of 60% of the Massachusetts median. Low-income customers are assumed to receive a 25% discounted gas rate. Chart includes energy bills only, excluding levelized equipment costs.

Across all scenarios, non-migrating customers face higher monthly energy costs than customers that adopt a decarbonization technology package. The difference between a migrating and a non-migrating customers energy burden varies between scenarios due to differences in technology packages and rates. The figures illustrate the following per technology package:

- **Efficient Gas Furnace.** Customers adopting an efficient gas furnace see bill benefits compared to a "standard" package on the short term, mostly as a result of appliance efficiencies and building shell benefits. However, this package results in affordability challenge on the long term as monthly customer energy costs increase over time due to increasing commodity costs as more renewable gases are blended into pipeline supply. Under those conditions where commodity costs continue to drive up monthly customer energy bills, a feedback loop may occur over time with customers choosing to convert to all-electric appliances as all-electric costs become cheaper compared to the costs of gas.

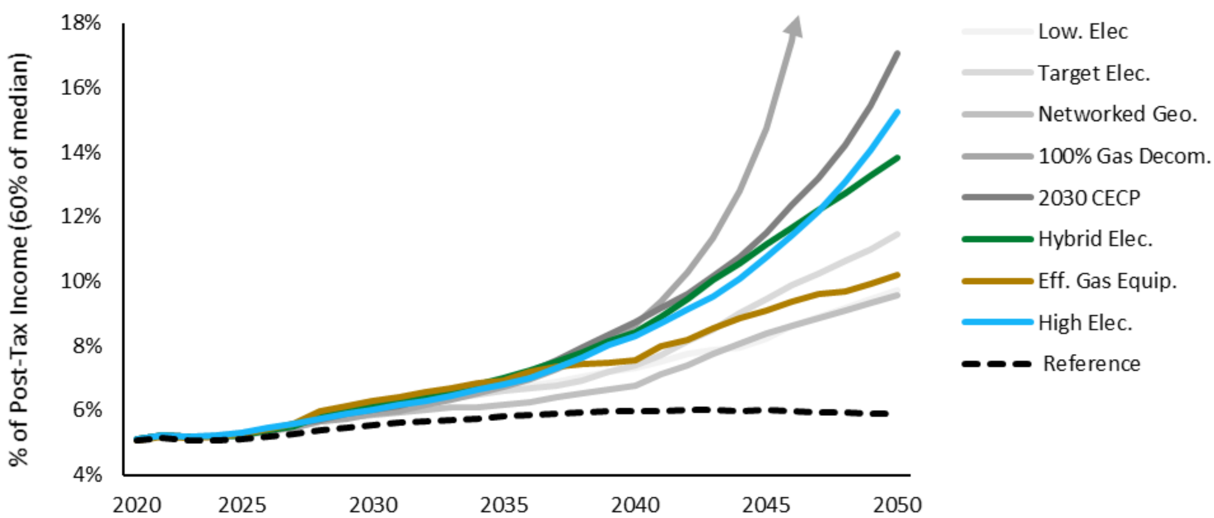
- **ASHP.** For customers adopting a technology package that consists of an ASHP and other electric appliances, heating-related customer bills decline over time as a result of continuous appliance efficiency improvements. However, in scenarios with high levels of electrification, the level of customer migration away from the gas system will lead to significant affordability challenges for remaining LDC customers who continue to bear the cost of the system.
- **ASHP + gas furnace backup (hybrid).** Customers adopting an ASHP combined with a gas furnace backup see an increase in customer bills compared to a "standard" package as heating demand is shifted to a combination of electricity and gas. This technology package does not include building shell upgrades to align with the scenario parameters of the Hybrid Electrification scenario.[79] Under current volumetric rate structures, non-migrating customers face higher costs than migrating customers. This imbalance grows after 2040 as volumetric rates increase due to a mixture of declining throughput and increasingly high blends of renewable gas. The gap between migrating customers and non-migrating customers in this scenario may be mitigated by collecting delivery costs over a fixed or demand-based basis, as discussed in Part II of this Report.
- **Networked Geothermal**. Customers connected to a networked geothermal system experience significant electric bill savings as a result of the high efficiency benefits of those systems. However, it is assumed these customers will need to contribute to recovering the utility installation costs of the system captured in the Revenue Requirement analysis in Chapter 4.[80]

Figure 37 illustrates how low-income customers that are unable to participate in decarbonization are likely to spend an increasingly high share of their income on energy, from approximately 5% today, to over 15% in 2050. This is further illustrated in Figure 38 by scenario.

[79] See Text Box 1 for more detail on this assumption.

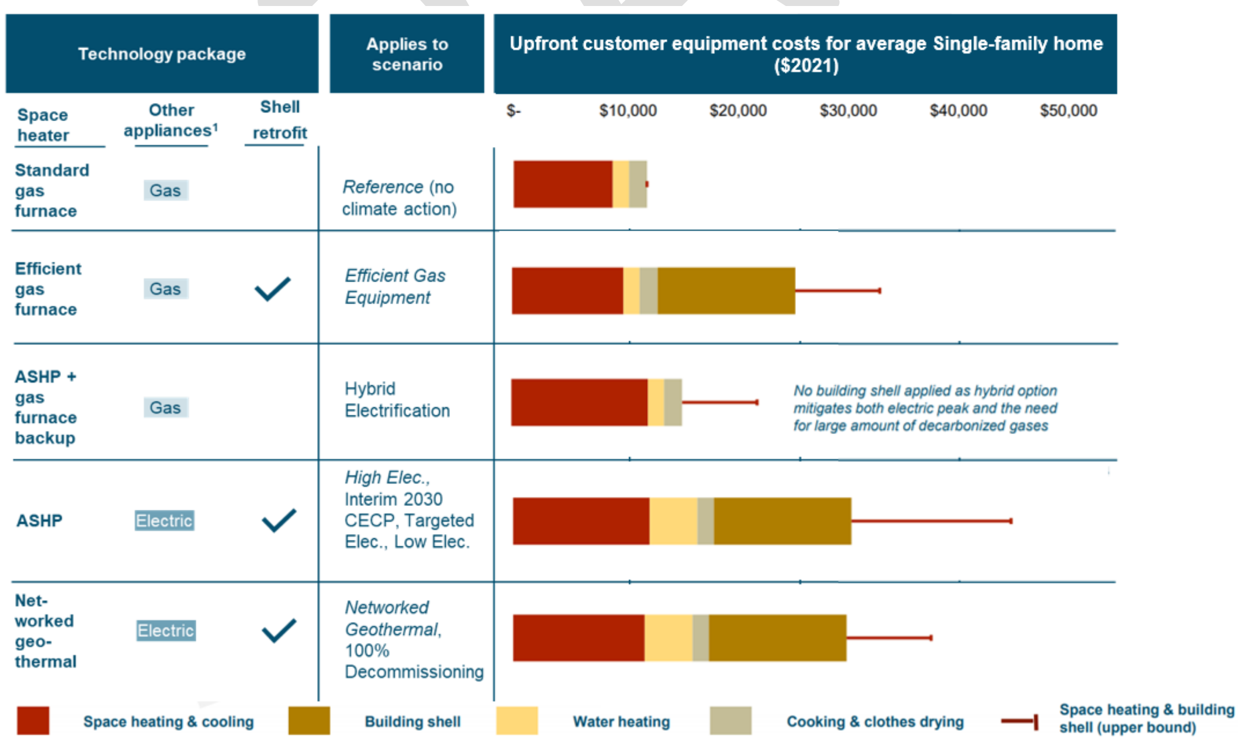
[80] In looking at the allocation of networked geothermal costs, there is a significant difference in customer costs if geothermal delivery costs would be shared over all LDC customers, or geothermal customers only. In Figure 37 above, it is assumed that those costs would be socialized across all customers, leading to more beneficial bills for those customers connecting to a networked geothermal system. A just allocation of these costs may shift over time as more customers are connected to the system and fewer customers remain to cover the costs of the gas system.

Figure 38. Non-migrating customer energy burden for low-income customers (% of annual income spent on gas and electricity). A low-income customer is defined as a customer with a household income that does not exceed 60% of the state median income level.



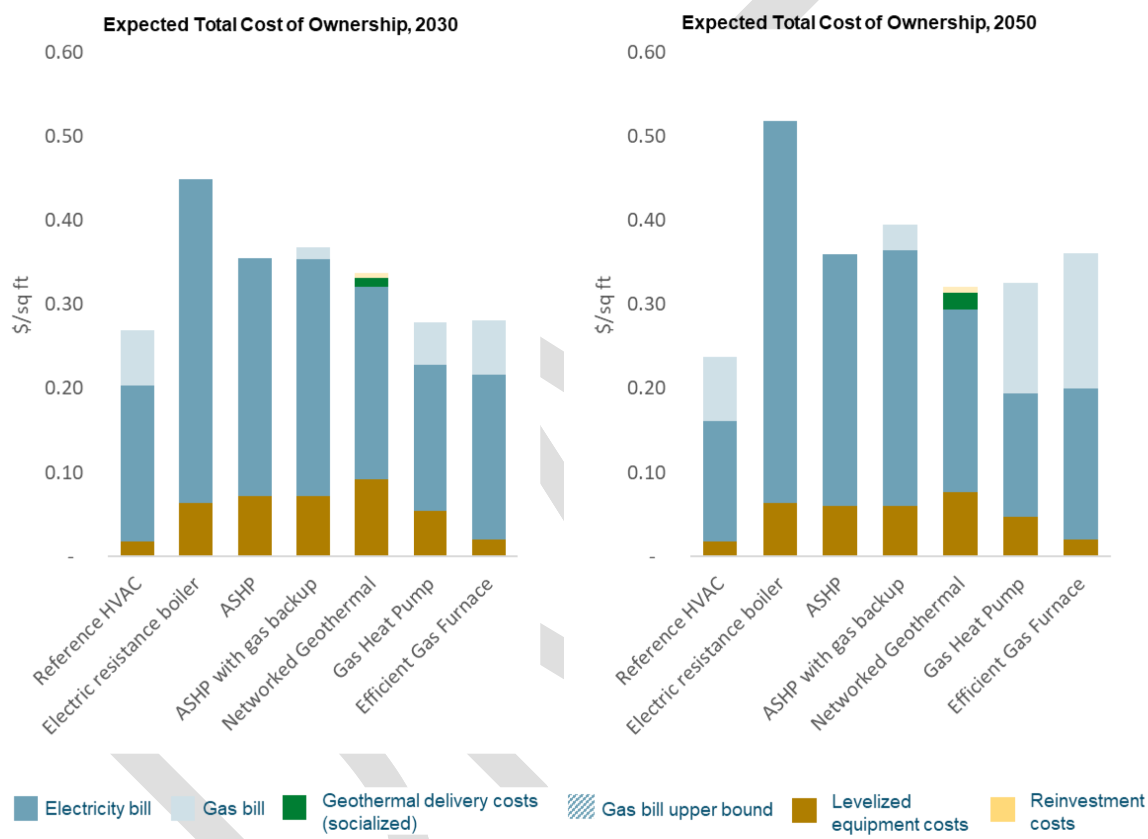
Across scenarios, although decarbonization efforts may result in flat or lower monthly energy costs, upfront capital costs are a significant barrier for customers, especially low-income, to participate in decarbonization efforts. This is illustrated in Figure 39.

Figure 39. Overview of customer upfront costs by technology package.



Similar results and challenges regarding decarbonization are found in the commercial sector, although the heterogeneity of this class warrants more tailored investigation. An example of bill impacts for a prototype commercial retail customers for a set of key technology packages is provided in Figure 40. Costs are shown for "migrating" customers (i.e. customers adopting the technology) in 2050 counterfactual to a reference technology package. An overview of assumptions and results for the commercial sector, including detailed bills per 5-year increments, are provided in Appendix 1.

Figure 40. Estimated total cost of ownership for a commercial retail customer. Gas bills are shown using Eversource (NSTAR) rates.



Policy implications

With regard to the adoption of decarbonization technologies, a significant burden exists in the upfront capital costs of appliances, as well as the costs associated with implementing building shell retrofits. In order for decarbonization in the Buildings sector to occur at the pace illustrated in these pathways, expanded policies aimed at providing customer incentives, that build upon the incentives provided in the MassSave program, would need to be established. In addition, this section shows how decarbonization pathways lead to significant differences in customer bills for customers adopting a decarbonization technologies and customers that remain on the gas system, which leads to customer equity issues as described in more detail below.

Customer Equity

With customers migrating from the gas system, cost shifts and equity issues can be observed across generations of LDC customers, migrating vs. non-migrating customers, and between rates classes (residential vs. non-residential). Given the upfront costs required to convert end use applications from natural gas to electricity, those customers that are unable to fund these costs (e.g., customers who qualify for low-income rate, many of whom are likely to reside in designated environmental justice populations) are more likely to remain as LDC customers and bear a disproportionate cost responsibility for LDC distribution system costs

In addition to the concerns regarding inequitable outcomes associated with the recovery of LDC delivery costs[81], pathways present other equity challenges such as procedural (e.g., broad EJ population participation in the various regulatory and permitting processes associated with decarbonization), customer communication (e.g., distributing information to address English Isolation), and construction and/or decommissioning of energy infrastructure, particularly in EJ communities, at the scale required by the pathways.

Key findings and observations

As demonstrated in Chapter 4, pathways with dramatic reductions in natural gas system utilization resulting from significant customer migrations away from the LDCs lead to equity issues as – absent changes to current cost-recovery approaches – the recovery of the cost associated with the LDC distribution system are left to a declining number of remaining customers. In these pathways, by 2050, costs per customer reach levels that would be unrealistic (e.g., $30,000 to over $70,000 per customer per year), especially considering that low-income and EJ customers may be less able to self-fund or finance the cost of technology conversion and thus may be overrepresented in the remaining natural gas customer base. Pathways with more moderate levels of electrification result in less significant cost shifting, but still show costs per customer that are 40% to 50% above the Reference case by 2050. Pathways that continue to utilize the gas distribution system, and maintain or grow the number of natural gas customers, minimize cost shifting and result in LDC revenue requirements per customer that are comparable to Reference.

In addition to the shift from migrating to non-migrating customers, there is also the potential for cost shifting between rate classes. For example, pathways with rapid electrification in the residential sector are more likely to result in natural gas distribution system costs shifting to non-residential segments, which likely include harder-to-electrify industrial sectors. As a result, in these pathways, there may be certain challenges and equity considerations associated with cost allocation across customer classes that will require LDC cost recovery and rate design changes as well as regulatory review and approval.

Overall, and regardless of the pathway, there are various customer equity challenges to consider, including:

- Equitable distribution and recovery of LDC delivery costs – the allocation of historical or planned LDC capital investments, which have been approved by the Department to serve and benefit all customers, should be aligned and recovered from customers responsible for that cost incurrence. Over time, absent changes to existing regulatory policies, decarbonization pathways that rely on

[81] The Consultant's relied on various model outputs to inform and frame the discussion of Customer Equity implications; however, to understand the magnitude and pace of inequitable outcomes for natural gas customers across pathways, our analysis primarily focused on forecasted LDC revenue requirements per customer presented in Chapter 4

significant electrification result in inequitable outcomes regarding the recovery of LDC delivery costs.

- Procedural equity and inclusive decision making – given the complexity and diverse implications of decarbonizing the Massachusetts economy and Buildings sector specifically, all pathways require improving access and engagement from all stakeholders. This is especially true for communities and individuals historically underrepresented in regulatory proceedings (e.g., EJ populations). As such, the Massachusetts D.P.U. has already initiated docket 21-50 regarding broadening participation in regulatory proceedings.[82] There are similar efforts occurring at a federal level via FERC's Office of Public Participation.[83] These policies, which focus on increasing participation will be essential to ensure that diverse interests are reflected in decarbonization planning and strategies.
- Decommissioning and construction of energy infrastructure – pathways present various equity issues related to both existing infrastructure retirements and new energy infrastructure construction, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of LDC infrastructure. These issues are particularly important for EJ populations that are generally overrepresented in communities already hosting energy infrastructure (e.g., LDC on-system LNG and propane assets) as discussed in Chapter 3.

Policy implications

The magnitude and pace of electrification associated with a particular pathway will impact LDCs and the Department's ability to develop and implement regulatory policies that mitigate potential cost shifts and associated equity issues. Especially pathways with a rapid customer transition likely necessitate more expansive regulatory policy changes on a shorter timeframe to manage costs and mitigate inequitable outcomes. These pathways may result in more immediate costs shifts that require policy intervention sooner in the transition period.

Pathways with slower customer transitions can provide LDCs and regulators with a longer lead time to develop and implement new rates (or new rate designs) before significant natural gas customer migration occur, and limit potential "first mover" cost shifting.[84] In addition, such pathways – by maintaining a relatively greater level of utilization of the gas system over the coming decades, can mitigate the risk of excessive cost burden on remaining gas network customers through less drastic regulatory measures. For example, to mitigate these potential unintended cost shifting consequences, existing and new incentives may need to be implemented to provide incremental decarbonization incentives to low income and EJ populations. Additionally, incentives designed to benefit both landlords and tenants would help address current misalignment of interests amongst parties.[85] Although this is true for all pathways, these incentives may be especially relevant for pathways with higher levels of customer transitions.

[82] Massachusetts D.P.U. 21-50. *Notice of Inquiry by the Department of Public Utilities on its own Motion into procedures for enhancing public awareness of and participation in its proceedings.* Vote and Order Opening Inquiry. April 16, 2021.

[83] Federal Energy Regulatory Commission (FERC). Report on The Office of Public Participation. June 24, 2021. https://www.ferc.gov/media/ferc-report-office-public-participation

[84] Regardless of pathway, customers that migrate at the beginning of the transition are more likely "early adopters" who have the ability to finance electrification without LDC or third-party support. However, low-income customers, EJ communities, and tenants are generally less able to afford upfront decarbonization costs.

[85] For example, landlords may not be incentivized to incur upfront capital and labor costs associated with converting equipment or appliances if the costs cannot be recovered and the benefits are realized by tenants.

Also, each pathway has a significant level of energy infrastructure construction, and to the extent possible, policies will need to address and mitigate impacts on EJ communities and low-income populations associated with locating and constructing of energy infrastructure as well as the decommissioning of any LDC facilities.

6. Pathway Commonalities, Low-regret Strategies and Key Differences Across LDCs

Achieving net-zero emissions across the economy in the Commonwealth of Massachusetts is transformational. In all scenarios, rapid changes in technology deployment are needed, affecting how energy is used, delivered and supplied. Those changes in turn result in a multi-faceted set of impacts on the LDCs' and their customers.

As illustrated in previous chapters, pathways that rely on a mix of technologies, including scenarios with hybrid electrification, may be better able to balance the costs and risks involved with decarbonization than scenarios that rely more heavily on single technologies or strategies. Even in scenarios with a mix of technologies, large-scale transformation of technology and customer adoption challenges still exist, as do challenges around energy affordability.

Commonalities across Scenarios and LDCs

Despite long-term uncertainty on the direction of decarbonization, there are several commonalities visible across scenarios. This indicates that any successful decarbonization pathway is likely to include the following set of strategies while keeping optionality for longer term changes:

- Renewable gas
- Energy efficiency
- Building electrification
- Renewable electricity, backed by firm capacity

Renewable Gas

Most decarbonization pathways analyzed in this Report blend in up to 5-10% of renewable gases in the gas distribution pipeline to support achievement of the 2030 GHG goal in the Commonwealth. Despite the higher costs of renewable fuels, these moderate levels of blending do not substantially increase the cost of gas supply by 2030. In particular, local biogas resources derived from anaerobic digestion are leveraged in all scenarios. These resources are limited in quantity, but given their commercial maturity represent a near-term action that the LDCs can pursue to support decarbonization.

Most pathways also envision a role for importing biomethane resources from outside the Commonwealth, similar to how the LDCs and other retail providers procure natural gas today. The resource potential for these fuels is substantially larger than that of local biogas, but there are uncertainties with respect to what share of that potential will be accessible by the LDCs. Under an economy-wide, national approach to decarbonization, there will be competing demands for these resources, particularly from hard-to-electrify segments of the economy like industry or aviation. Ultimately, policy instruments, discussed in Part II of this Report, will be needed to drive demand for renewable fuels and the design of those instruments will impact the costs and quantities of fuels available to the LDCs.

A strategy to increase the level of blending of renewable gases into the gas pipeline system is in line with policies currently under proposal in Massachusetts. The Interim 2030 CECP released in December 2020 announced the installation of a Commission on Clean Heat to investigate the possibility of a heating fuel emissions cap. An increase of renewable gas blending levels into the Commonwealth's distribution system would be a concrete step in reducing the carbon intensity of pipeline gas.

An outstanding question with respect to the role of renewable gases in the Commonwealth is how their lifecycle emissions impacts will be treated. Consistent with the Massachusetts Greenhouse Gas Inventory at the time of publication, this study assumes that the portfolio of renewable fuels selected is GHG neutral, as further discussed in Appendix 1. In practice, the actual GHG emissions associated with these fuels will be different. Under GHG accounting frameworks used elsewhere, certain renewable gas feedstocks carry positive lifecycle emissions, while others are considered to result in substantial negative emissions[86]. Recent research has also focused on incremental methane emissions associated with renewable gas production as an important consideration.[87]

Energy Efficiency

Energy efficiency is a foundational strategy to enable decarbonization of heating across all scenarios, reducing challenges associated with both electrification and decarbonized fuel-based strategies:

- Energy efficiency measures decrease the impacts of electrification on the electricity system, reducing both energy system costs and constructability challenges. Building shell retrofits in particular decrease the thermal demands of buildings, while improvements in the performance of heat pumps can substantially reduce annual loads and peak demands. Notably electrification is also a form of efficiency and is currently included in the LDCs' proposed three-year energy efficiency plans.[88]
- Energy efficiency also reduces the quantities of renewable fuels required, particularly those that are the least technology mature and most likely to carry substantial incremental costs relative to natural gas. The high cost of renewable gases creates value for efficient gas appliances, including a potential role for gas heat pumps.

All scenarios include a portfolio of energy efficiency measures, including appliance efficiency and efficiency from building shell retrofit measures. Building shell retrofits are foundational to most decarbonization pathways, but also come at significant upfront costs that are unlikely to be borne by building owners alone. Therefore, expanded policies aimed at reducing homeowner costs are required to achieve the level of efficiency assumed in this analysis. Those might include efforts to account for the future energy system value of shell retrofits like avoided electric generation and delivery infrastructure to serve winter peak demands, as well as reduced requirements for costly renewable gases.

Investments in efficiency measures will need to be calibrated against the scale and nature of building decarbonization that occurs. For example, hybrid electrification strategies may require less extensive building shell retrofits because the back-up heating system reduces the peak demand impacts of electrification, and the heat pump reduces reliance on higher cost renewable gases.[89] Similarly, investments in high efficiency gas appliances are more likely to be economic and reduce emissions in segments of the gas network with ongoing utilization. In contrast, these investments are less likely to be beneficial in segments of the network where networked geothermal or targeted electrification initiatives are likely to occur in the near-term. Such considerations would need to be balanced against increased

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[86] See, for instance, the CA-GREET3.0 model used in the California Low-Carbon Fuel Standard. https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation

[87] Grubert, E. 2020. "At scale, renewable natural gas systems could be climate intensive: the influence of methane feedstock and leakage rates." *Environmental Resource Letters*. Vol 15, No 8. https://iopscience.iop.org/article/10.1088/1748-9326/ab9335

[88] See, for instance, https://ma-eeac.org/wp-content/uploads/Exhibit-1-Three-Year-Plan-2022-2024-11-1-21-w-App-1.pdf

[89] While this report does not assume substantial building shell retrofits in buildings with hybrid heating because those retrofits are not cost effective, there may be less extensive retrofits that are cost-effective. In addition, there may be other reasons to undertake shell retrofits apart from energy system value, such as occupant comfort.

complexity associated with developing and administering energy efficiency programs that are differentiated by geography.

Building Electrification

Building electrification plays a key role in decarbonizing heating in most pathways. The scenarios modeled for this report confirm past work that has identified electrification as a foundational pathway to decarbonization that leverages commercially available products that are technically viable across most of the Commonwealth's building stock. However, the results of this work also indicate that there are challenges associated with electrification, namely the upfront cost of retrofits to consumers, higher operating costs over the next decade, potential for large electric infrastructure impacts, gas system cost-recovery challenges and workforce transition considerations.

A consistent finding across pathways modeled here is that hybrid electrification strategies capture the key advantages of electrification, while mitigating challenges. Hybrid electrification substantially reduces gas throughput, mitigates electric sector capacity impacts from electrification of heating, and may carry lower retrofit costs in some buildings compared to all-electric options. A decarbonization strategy with high levels of hybrid electrification indicates an ongoing, albeit substantially transformed, role for Massachusetts' gas distribution networks. This outcome reduces cost recovery and associated equity challenges. To do so, this strategy requires ongoing investments in the gas system. While some of those costs may be avoided by an all-electric approach, continued use of the gas system results in cost savings from avoided electric infrastructure additions that are larger than the incremental ongoing cost of the gas system (as shown on the cost overview in Figure 32).

All-electric solutions are also likely to have an important role in decarbonizing heating in Massachusetts, alongside hybrid approaches. For example, all-electric new construction can be accomplished a lower cost compared to retrofits and are less likely to cause large electric system impacts as new buildings generally have lower heating demands. In pathways with substantial reductions in gas system utilization, all-electric new construction will be an important strategy to reduce the magnitude of cost recovery challenges on the gas system. There will also be opportunities for all-electric solutions in existing buildings. Such solutions may be particularly attractive in cases where neighborhood or community level adoption of electrification can enable gas system cost savings, though the extent to which such opportunities will be available requires additional research.

Renewable Electricity, Supported by Firm Capacity

All scenarios require a transformation of the electric sector from fossil to largely renewable resources to reach net zero emissions, regardless of the level of electrification pursued. This includes the installation of offshore and onshore wind, significant amounts of solar, as well as supporting investments in energy storage, transmission and distribution infrastructure to deliver renewables to the Commonwealth. Consistent with other studies, this report identifies an important role for firm capacity resources as a complement to a high renewables system across all scenarios. Gas infrastructure may have a role in providing that firm capacity in the form of gas turbines that are used infrequently and fueled by hydrogen over time. Importantly, the amount of firm capacity provided by gas in these scenarios is an upper-bound estimate. Past work by E3 and others indicates that a portfolio of firm capacity resources will be needed, including emerging long-duration energy storage technologies.

Research and Development Needs

In addition to these common strategies, several decarbonization technologies and supporting measures are worth further research and development to better understand their costs and resource potential:

- Hybrid system operation
- Networked geothermal
- Renewable hydrogen and synthetic natural gas
- Targeted electrification to enable decommissioning of gas assets

Hybrid Electric-Gas Heating System Optimization

As discussed above, hybrid electrification is a promising strategy to decarbonize building heating in Massachusetts. However, there are outstanding operational questions with respect to the maximizing the benefits of hybrid heating, both at a customer and system level. For example, the switchover point between a heat pump to a back-up system could include HVAC installer heuristics, consumer response to retail rates, or control signals from load aggregators.[90] The benefits of hybrid electrification are derived to a large extent from value provided to electric systems but, given non-overlapping electric and gas service territories, operational innovation will be needed to ensure those benefits are captured.

An example of a pilot program that could help work through the operation of hybrid systems is the Freedom Project from the United Kingdom.[91] That project involved a collaboration of two distinct gas and electric network companies to implement hybrid electrification solutions to the benefit of both systems and their customers. Similar research is underway in Canada, as described in Part II of this Report, and would be valuable in Massachusetts for both utilities' dual fuel service territories and in those parts of the state with different electric and gas utilities.

Networked Geothermal

Networked geothermal systems have the potential to provide renewable decarbonized heating without causing large wintertime electric peak demands, while leveraging the LDCs' existing expertise and workforce. However, questions remain around the feasibility and long-term cost of this option at scale.

In order for networked geothermal solutions to scale, neighborhood level retrofits will need to be achieved at reasonable cost. Such an outcome is most likely in cases where networked geothermal investments avoid gas infrastructure investments, rather than being installed as a redundant energy system. However, even in cases where gas infrastructure can be avoided, networked geothermal systems require substantial capital investments and result in challenges associated with converting large numbers of customers at the same time. For example, there are practical challenges associated with getting every customer to elect to transition from gas to networked geothermal service. Related, not all equipment within a given area will be at end-of-useful-life, so it is likely that there will be stranded customer costs associated with networked geothermal even if a gas infrastructure investment can be fully avoided.

Networked geothermal installations have been installed in a handful of settings, particularly campuses[92], but have not yet been proven at the scale's envisioned in scenarios here. More examples across a wide variety of project types are needed to flesh out the role of these technologies more fully in the Commonwealth. Ongoing pilots by Eversource and National Grid will help to reduce the uncertainties associated with these systems.

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[90] For more information on switchover practices and temperature points in existing hybrid installations in Massachusetts, please see: https://ma-eeac.org/wp-content/uploads/MA20R24-B-EOEval_Fuel-Displacement-Report_2021-10-13_Final.pdf

[91] See, for example, https://www.westernpower.co.uk/projects/freedom

[92] See, for instance, https://www.coloradomesa.edu/facilities/sustainability/geo-systems.html

Renewable Hydrogen

Renewable hydrogen has a role in all pathways modeled, including for limited direct use in the buildings sector, for potential use in providing electric sector firm capacity, or for use in medium and heavy-duty transportation. However, renewable hydrogen has not been deployed anywhere in the world at the scales envisioned in this analysis. This analysis investigated how hydrogen would be produced, delivered to, and used in Massachusetts. From this and other work, the Consultants have concluded that the production of hydrogen in Massachusetts is not cost-effective compared to the delivery of hydrogen from out of state, particularly as a result of the absence of large-scale storage opportunities. This finding raises questions associated with the deliverability of hydrogen to the Commonwealth and the opportunity to use existing or new pipeline infrastructure. In addition, research on the symbiosis between offshore wind capacity and opportunities for hydrogen production from otherwise curtailed electricity could further help define the role of hydrogen in Massachusetts.

To summarize, more research is needed to answer hydrogen-related questions including:

- What are the best and most feasible sources for renewable hydrogen production, taking into account potential production from otherwise curtailed offshore wind electricity?
- Is there a role for hydrogen produced via methane reformation with carbon capture and how would the lifecycle emissions of those be treated?
- Regardless of production process, to what extent should hydrogen production occur in- vs out-of-state?
- How will hydrogen be transported to the Commonwealth? Is it feasible to convert existing inter-state pipelines to deliver increasing blends of hydrogen?
- To what extent can LDC infrastructure handle blends of hydrogen on an operational basis? How does that interact with conversions from leak prone pipe to plastic?
- How will hydrogen be stored within Massachusetts, including for system capacity and local reliability needs?

In the face of those uncertainties, initial pilots to explore blends of hydrogen in the LDCs' systems could be a promising next step.

Synthetic natural gas could emerge as an important drop-in replacement for fossil methane, unlike hydrogen which at large scale would require pipeline upgrades to distribute and installation of end uses capable of burning hydrogen. SNG is not commercially produced in the United States and is likely to carry high costs, but could nonetheless have a role as part of broader strategy to decarbonize building heating. Given this technology's relatively low level of commercialization and the fact that it is unlikely to be needed this decade, the Consultants recommend that the LDCs engage in research and development initiatives related to SNG and monitor its commercialization in other markets.

Targeted Electrification to Enable Decommissioning of Gas Distribution Assets

Targeted electrification may offer opportunities for savings in the gas distribution system, potentially reducing the cost impacts of electrification on remaining customers. However, many open questions remain around the extent to which targeted electrification can enable gas system cost reductions, for similar reasons to networked geothermal. The initial analysis conducted by the Consultants in this Report suggests that these strategies are not a panacea for the cost recovery and customer cost challenges described above. However, cost reductions are nonetheless likely to be an important component of strategies to manage the non-migrating customer impacts associated with achieving the Commonwealth's decarbonization goals.

Strategies that achieve sufficient customer adoption of electrification to enable cost reductions need further investigation. Hurdles to achieving customer adoption that enable decommissioning are likely to be lowest in areas with high propensities to electrify, but it is unclear how those areas will align with opportunities for gas system cost reductions. Other jurisdictions have begun to explore these questions. For example, the California Energy Commission has funded work to investigate opportunities for tactical gas decommissioning in close cooperation with utilities and other stakeholders.[93] Similar research in Massachusetts would be a valuable next step.

Distinctions among LDCs

The commonalities and areas for further research and development described above apply to all the LDCs, but as discussed in Chapter 3 each individual LDC has unique characteristics and circumstances that will inform what portfolio solutions are best suited to its customer and operational needs. Key distinctions include:

- **Customer Income Levels.** All LDCs serve low-income populations, making strategies to contain customer cost paramount. However, the share of those customers is particularly high for Berkshire, Liberty and Unitil. As a result, those LDCs will need to emphasize, and potentially receive support for, initiatives to reduce or overcome the upfront cost challenges associated with customer adoption of decarbonization measures. Customer income levels may also implicate the pace of customer-driven departures associated with rising gas commodity and delivery costs. A larger share of Eversource and National Grid's customers are higher income customers. Higher income customers are more likely to able to make the electrification investments necessary to insulate themselves from rising gas costs by departing the gas system altogether. As a result, larger presence of high income residents could mean that Eversource and National Grid are more susceptible to customer migration, which would impact their still substantial numbers of lower-income customer.
- **Building Stock**. Compared to elsewhere in the United States, Massachusetts has a relatively old building stock. Older buildings are, all else equal, more costly to electrify but offer greater opportunities for heating demand reduction via building shell retrofits. A substantial minority (from 17% to 40%) of homes within each LDCs service territory were built prior to World War II and most homes across the service territories were built prior to 1979. Among the LDCs, Eversource and National Grid's Colonial Gas territory serves a building stock that is relatively newer, while Liberty, Berkshire, Unitil and National Grid's Boston Gas territory units serve a relatively older building stock. In addition to age, building typologies are also a distinguishing feature among the LDCs. Liberty and National Grid's Boston Gas territories both have a high proportion of multi-unit dwellings compared to other LDCs. Multi-unit dwellings are also generally more challenging to electrify than single-family homes.[94] In addition, approximately 34% of the building stock is tenant-occupied, with higher percentages for Liberty and National Grid (Boston Gas), which complicates decision-making with regard to customer electrification.
- **Utility size & growth.** Eversource and National Grid serve 91% of the state's gas customers, making those companies substantially larger than Berkshire Gas, Liberty and Unitil. Given economies of scope and scale, Eversource and National Grid may therefore have more institutional capacity to be prime movers across multiple facets of the state's gas transition. Both Eversource and National Grid are also expected to experience higher levels of customer

[93] See https://www.energy.ca.gov/event/workshop/2021-11/staff-workshop-strategic-pathways-and-analytics-tactical-decommissioning

[94] See, for example, NYSERDA 2019. "New Efficiency: New York".

additions from new construction. These LDCs will therefore need to be strategic in assessing the opportunities and risks associated with customer additions, particularly in the context of potential futures with large numbers of customer departures.

- **System characteristics, including GSEP.** Key LDC system characteristics like remaining GSEP work and the density of their loads implicate the appropriateness of decarbonization solutions for each company. For example, Eversource and National Grid both have the largest amount of GSEP project work left to complete and a medium to high service area density. These characteristics suggest that there a larger proportion of these utilities system will undergo work in the coming decades and so there may be more opportunities for strategies like targeted electrification and networked geothermal. However, the relatively higher density of customers and loads for those utilities may increase the complication of any given targeted electrification or networked geothermal project. Higher densities imply more customer conversions are required for a project to succeed. Gas systems in dense areas may also be less hydraulically separable based on system reliability and other operational factors. In contrast, Berkshire, Liberty, and Unitil have fewer GSEP projects remaining to complete. As a result, the role of targeted electrification or networked geothermal solutions may not be as large for these utilities.
- **Large customers.** Among the LDCs, Berkshire Gas and Unitil deliver the largest share of their gas volumes to industrial customers, for whom electrification options are more limited. Higher costs could put some portion of these loads at risk, particularly if the Commonwealth's policies do not consider impacts on trade exposed industries. Large customers, including industrial and commercial accounts, also account for most transportation volumes served by the LDCs. Eversource and National Grid in particular serve large numbers of large-commercial transportation customers, while Berkshire Gas is unique in the proportion of institutional, primarily higher education, transportation customers it serves. These customers may pursue a heterogenous set of decarbonization initiatives that are tailored to the needs of their facilities and organizational priorities.
- **Gas/electric utility service territory overlap.** Massachusetts is home to gas and electric utilities with non-overlapping service territories. Eversource, National Grid and Unitil all provide both electric and gas service in Massachusetts, however, they each provide both gas and electric service to between 39% and 87% of their customers. Berkshire and Liberty are gas only utilities in Massachusetts. Dual fuel utilities, where their territories overlap, could be well suited to identify and implement strategies that deliver decarbonization solutions, like targeted electrification or networked geothermal systems, in a manner that makes optimal use of both gas and electric systems. That coordination challenge will be more challenging for non-overlapping and gas-only service territories, indicating that cross-company electric and gas coordination will be needed to deliver on an integrated approach to decarbonization.

Recommended Strategies for LDCs

Considering the commonalities and low-regret strategies across decarbonization pathways, research and development needs and characteristics of the Massachusetts' gas LDCs, the Consultants recommend the following near-term actions for LDCs to pursue in support of the Commonwealth's climate goals. Some of these actions involve implementation challenges regarding the current policy and regulatory landscape. These challenges, and proposed reforms to address these them, are described in detail in Part II of this Report.

1. **Develop procurement strategies for renewable gases.** This analysis shows that blending limited amounts of renewable gases into the pipeline would result in a reduction of GHG emissions without substantially increasing the costs of gas. The Consultants recommend all LDCs to develop procurement strategies for renewable gases, starting with relatively low-cost resources available within region. Additional near-term action could involve investigating the deliverability of biomethane, hydrogen and synthetic gases from a broader range of sources and regions. Early action on these fuels could help to further clarify their role in supporting the state's decarbonization goals and help to ensure these fuels can scale within the timelines (between 2025 and 2040) identified in the pathways.
2. **Investigate opportunities for renewable hydrogen blending and synthetic gas R&D.** As noted in this Report, development needs exist regarding the blending of renewable hydrogen into the distribution system and the commercialization of climate-neutral synthetic gases produced from renewable hydrogen. The Consultants recommend the LDCs pursue pilots to investigate to what extent hydrogen can safely be added to the network without the need for customer equipment or pipeline upgrades. In addition, the Consultants recommend LDCs to engage in R&D opportunities related to the development of climate-neutral synthetic gas facilities.
3. **Develop R&D initiatives, pilots and programs for networked geothermal systems, including opportunities for strategic GSEP replacements.** This analysis shows how networked geothermal systems can have benefits to customers, the energy system as a whole and the LDC business model, although many questions remain on the technical implementation, financing and potential gas system cost avoidance of related to these systems. Particularly for those LDCs with significant amounts of GSEP expenditures left, the Consultants recommend the development of pilot opportunities for networked geothermal systems and the potential for strategic replacements of GSEP capital programs. Should initial pilot prove successful, including those currently under development, then LDCs should consider developing networked geothermal programs to begin to scale this solution set.
4. **Promote adoption of energy efficiency measures such as building shells and efficient equipment via funding and customer education.** Most decarbonization pathways require a central role for LDC customers with regard to the implementation of building retrofits and the adoption of efficient heating equipment. The Consultants recommend that all LDCs continue to develop programs that promote the adoption of such measures via funding and customer education, for instance through Mass Save (or equivalent) program. In addition, the consultants recommend that the LDCs track progress of electrification and building shell retrofits in their customer programs against the pace of transition in the Pathways examined in this Report to determine if additional programmatic or policy support is needed.
5. **Promote adoption of building electrification, including hybrid strategies, via funding and customer education.** Building electrification is a central component of decarbonization. This Study illustrates that hybrid electrification strategies that keep a role for the gas system present the lowest level of challenge overall. Therefore, the Consultants recommend promoting the adoption of building electrification, including hybrid strategies and all-electric new construction where possible, and to investigate the most optimal operation of hybrid systems in support of the electric system.
6. **Investigate opportunities for gas system cost savings through targeted electrification pilots.** This Study shows that targeted electrification could reduce some gas system costs, but substantial uncertainties remain. Similar to recommendation 3, and particularly for LDCs with higher levels of GSEP expenditures, the Consultants recommend developing opportunities for gas system cost savings through pilots on strategic targeted electrification, including considerations of customer adoption and acceptance.

7. **As applicable, promote cross-company coordination to achieve an integrated gas & electric approach to decarbonization**. Specifically for LDCs that operate both gas and electric systems, the Consultants recommend promoting the cross-coordination of gas and electric planning to optimally serve customers as they decarbonize their heating supply. This includes integrating an operational approach to hybrid systems, as well as the investigation and proposal of cost recovery and rate structures that reflect a fair representation of costs and benefits across systems and customers.
8. **Protect customers, particularly low income and customers in EJ regions, from rate shocks by evaluating new rate structures.** As the potential for declining gas demand and customer counts are not aligned with current gas system cost recovery mechanisms, the Consultants recommend LDCs to work closely together with the Department in evaluating decarbonization-specific rate structures and evaluating and proposing new approaches to address cost recovery challenges, including changes to depreciation schedules and collecting some transition costs from non-LDC customers.
9. **Work collaboratively with communities to develop decarbonization plans that support low-income communities and prioritize equity.** As decarbonization efforts and LDC plans to address those affect a broad range of stakeholders and communities, with specific attention to low-income customers and environmental justice populations, the Consultants recommend the LDC to continue to work collaboratively with communities in developing plans that support low-income communities and prioritize equity.
10. **Develop decarbonization evaluation metrics, and actively monitor customer migrations and potential impacts to gas planning.** The exact timing and direction of decarbonization pathways is uncertain, and not all developments are within LDC control. For example, market developments such as heat pump cost declines or shifts in consumer preferences may spur customer migrations. The Consultants recommend that LDCs develop evaluation criteria and actively monitor GHG reductions, gas throughput and customer migrations, so that appropriate cost recovery challenges and impact to gas planning can be assessed and mitigated in a timely manner.

Importantly, the LDCs will need regulatory and policy support to act on these recommendations. A detailed description of regulatory and policy mechanisms to support decarbonization can be found in Part II of this Report. Part II builds on the scenario analysis and conclusions developed here by providing a set of regulatory options that both enable decarbonization and manage transition impacts on LDC customers.