ERM Report

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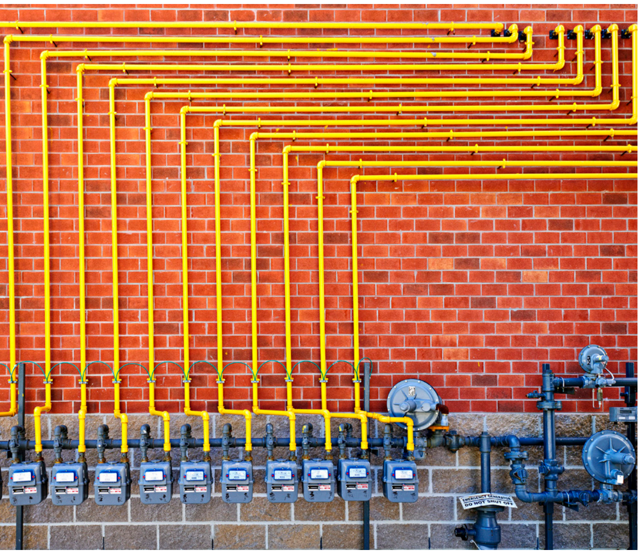

Long-Term Vision Analysis: New England

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Acronyms and Abbreviations

ASHP	Air source heat pump
ASHP+NG	Air source heat pump and natural gas; dual fuel
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COP	Coefficient of performance
Dth	Dekatherm
Gas HP	Gas heat pump
GHG	Greenhouse Gas
GSHP	Ground source heat pump
GW	Gigawatt
H_2	Hydrogen
IRA	Inflation Reduction Act
ISO-NE	ISO New England
LDC	Local distribution company
M-H_2	Methanated Hydrogen
MMBtu	Million British thermal units
MT	Metric tons
mtCO_2e	Metric ton of carbon dioxide equivalent
MW	Megawatt
MWh	Megawatt hour
NG	Natural gas
P2G	Power to gas
RNG	Renewable natural gas
T&D	Transmission and distribution

About this Paper

This paper was prepared based on engagement with the Downstream Natural Gas Initiative members and external advisors. It reflects the analysis and judgement of the ERM authors alone.

Brian Jones, Sierra Fraioli, Emily O'Connell, James Saeger, Lauren Slawsky, and Rachel MacIntosh of ERM made important contributions to this paper.

About the Downstream Natural Gas Initiative

The Downstream Natural Gas Initiative (DSI) is a group of leading natural gas utilities collaborating to build a shared vision for the role of utilities and the gas distribution network in the transition to a low-carbon future. DSI is facilitated and managed by ERM.[1] DSI is focused on opportunities to leverage the existing gas infrastructure to support near- and long-term environmental and economic goals and to address key technical and regulatory challenges related to these goals and opportunities.

Through this collaboration, DSI is advancing a Long-Term Vision and related strategies for natural gas utilities to reduce greenhouse gas emissions and support economy-wide emission reductions. For more information on DSI and its members, please visit https://www.erm.com/coalitions/downstream-natural-gas-initiative/.

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DSI's Long-Term Vision

Local distribution companies (LDCs) have a critical role to play in helping local, state, and federal governments meet greenhouse gas (GHG) emissions targets while maintaining safe, reliable and cost-effective energy service.[2] This analysis takes a closer look at how building decarbonization targets can be achieved through different emission reduction scenarios and finds that strategies that pair gas and electric system decarbonization solutions offer the most cost-effective pathway. Specific focus is directed at the energy requirements needed to meet winter heating demand, which vary drastically across the country, and can have consequential impacts on a region's emission abatement opportunities and associated costs. This analysis underscores how important regional considerations are in designing and implementing climate policies and offers utilities and policymakers greater insight into localized costs associated with different building decarbonization solutions.

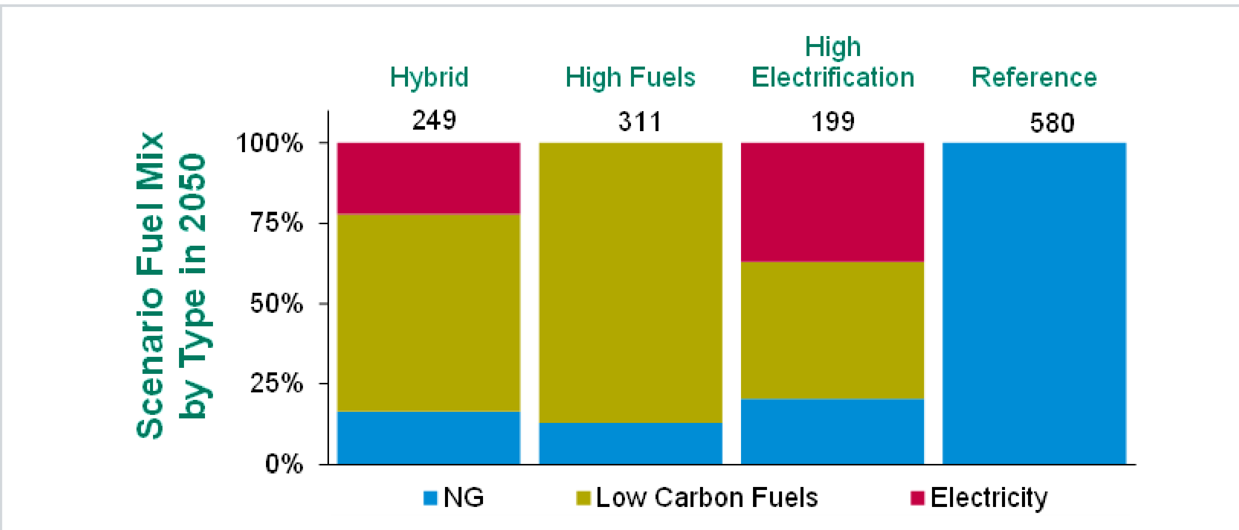
[1] M.J. Bradley & Associates (MJB&A) was acquired by ERM in March 2020.
[2] M.J. Bradley & Associates, an ERM Group Company, The Role of Gas Networks in a Low-Carbon Future, December 2020. Available at https://mjbradley.com/reports/role-natural-gas-networks-low-carbon-future.

Summary of Findings

This report summarizes three distinct decarbonization scenarios and the associated costs of decarbonizing natural gas end-uses in the New England region by 2050. It achieves this by examining the related impacts on the New England electric system, infrastructure requirements, and utility and customer costs. See Table 1. It is the first of separate regional analyses that will be released as part of DSI's Long-Term Vision.[3]

The scope of this study is focused on reducing emissions associated with existing natural gas demand from the industrial, commercial, residential sectors in New England. Three different pathway scenarios model a range of fuel mixes and equipment deployments to test the impact of different technology options on energy consumption, emissions reductions, and system costs. A reference case, following historical trends of steady growth in conventional gas use and associated emissions provides a baseline for comparison.

Table 1: Scenario Modeling Results Summary



Scenario Modeling Results Summary

	Hyrbid	High Fuels	High Electrification	Reference
Change in CO_2e Emissions by 2050 (% from 2020 base)	-92%	-92%	-92%	12%
Total Energy Demand in 2050 (million Dth)	249	311	199	580
Customers on Gas System in 2050	3.0	3.5	0.5	3.5
New Electric System Capacity Required by 2050 (GW)	5	NA	24	NA
Annualized Cost in 2050 (2022$ bil)	$16	$19	$20	$11

The most achievable, cost-effective, and reliable paths to decarbonize heating in New England are those that optimize available strategies including energy efficiency, decarbonized fuels, and electrification integration. This study finds the Hybrid Scenario, that leveraged decarbonization solutions across the gas and electric systems, to be the least costly pathway to decarbonize the building sector in New England.

[3] ERM is conducting analyses on additional geographic regions.

Additional key findings include:

- Energy efficiency is among the most cost-effective decarbonization measures available today.
- Dual-fuel (electric and gas), or hybrid heating strategies are a cost-effective method to achieve significant building sector emissions reductions in New England.
- Decarbonized fuels are an effective and scalable strategy when used in buildings for meeting winter peak heating demand in cold weather climates and difficult-to-electrify uses like industrial processes.
- Decarbonizing natural gas end-uses is highly dependent upon regional conditions. The interplay of factors such as climate, building stock, electric grid capacity mix, and seasonal heating demand create unique needs requiring New England-specific approaches to achieve reliable and cost-effective emissions reductions.

Across all scenarios, energy efficiency improvements lead to a decline of more than one third in the volume of conventional natural gas deliveries to customers. Additional emission reductions are driven by a combination of improvements to end-use equipment efficiency.[4]

All decarbonization scenarios rely on some level of alternative, low- or zero-carbon gaseous fuels in substitution for conventional natural gas to support emissions reductions. Conversion of end-use customers from conventional gas-fired heating appliances to high-efficiency electric and gas appliances is the central mechanism by which each scenario achieves substantial emissions reduction by 2050. The volume of conventional natural gas declines to 11 percent to 20 percent of total 2050 energy demand across all scenarios. Informed by current research on decarbonized fuels, this study assumes that by 2050, methanated hydrogen may be more cost-effective than renewable natural gas. Therefore, to help moderate costs, most of the study period has a greater reliance on power to gas (P2G) in each scenario.[5] The actual future cost-effectiveness of low- and zero-carbon fuels will depend on several variables such as feedstock availability and pace of technological development.

In the cold-weather climate of New England, the greatest driver of costs is the electrification of space heating and associated electric generating capacity needs to meet increasing winter peak electric demand. Each of the decarbonization scenarios costs more than the Reference scenario, which has a projected cost of just over $11 billion in annualized costs. The Hybrid scenario is projected to be the least-cost decarbonization path, incurring just under $16 billion in annualized costs in 2050, 42 percent higher than those projected for the Reference scenario in that year. The High Fuels scenario is projected to cost just under $19 billion annually by 2050, a cost premium to the Reference scenario of 71 percent, and the High Electrification scenario is projected to cost over $20 billion in annualized costs, 84 percent greater than the Reference scenario.[6] These electric system costs include new generation capacity as well as transmission and distribution (T&D) upgrade costs to serve the increasing electric demand.

Decarbonization approaches that work to contain rapid increases in the winter peak demand over the medium- to long-term are more cost-effective. Such strategies include building sector heating that relies on a dual-fuel or hybrid model in which electrified heating is deployed when most efficient and cost-effective, while decarbonized gas-fired space heating serves customers during the coldest temperatures of the heating season.

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[4] Most of the equipment efficiency gains are the result of replacing traditional gas-fired furnaces with highly efficient air source heat pumps (ASHPs) and ground source heat pumps (GSHPs). Depending on the scenario, there are additional efficiency gains from deployment of gas heat pumps replacing older, less efficient equipment.

[5] Power to gas (P2G) is the process of converting excess renewable energy into a synthetic natural gas that is primarily hydrogen and carbon monoxide, which can be injected directly into existing conventional natural gas pipeline infrastructure.

[6] Total costs represent the costs to significantly decarbonize current load of natural gas from use in buildings, excluding gas used by large electric generators. Costs include electric system, energy efficiency, heating equipment, and electricity (for electrified load) and natural gas service costs.

In the Hybrid scenario, buildings shift from electrified heating with highly efficient air source heat pumps (ASHP) to gas-fueled heating when the outdoor air temperature reaches 20º Fahrenheit (the model assumes a hybrid heating crossover point of 20º Fahrenheit).

The comparison of the costs and use of ASHPs between the Hybrid and the High Electrification scenarios on a per metric ton of reduction basis highlights one of the key findings of this analysis: air source heat pumps can be among the most cost-effective strategies for the decarbonization of natural gas end-uses. However, ASHP's cost-effectiveness depends on limiting their impact on the electric grid: cost-effectiveness and energy efficiency decline precipitously when the temperature dips below 20º Fahrenheit and would drive winter electric demand on the grid to exceed projected peak summer demand. The transition from summer peaking to winter peaking would drive the need for significant and costly electric resources.

Customer impacts vary across scenarios. In the High Fuels scenario, 3.5 million customers are serviced by the gas network in 2050, compared to the 2.8 million customers served today, while the High Electrification scenario shifts nearly 90 percent of these customers to the electric network. The Hybrid scenario retains 3 million customers.

All-customer average rates in the decarbonization scenarios would increase substantially by 2050, relative to the Reference scenario, due to a combination of decreased gas throughput and higher commodity costs for low- and zero-carbon fuels. Rapid migration of customers away from the gas system creates a risk of burdening remaining customers who are slower to convert or who cannot convert, including many economically vulnerable residential customers. The energy transition is likely to require a thorough redesign of rate structures to moderate impacts and distribute system costs differently across customers and customer classes. Decarbonizing natural gas end-uses in the building sector will incur costs regardless of the pathway chosen. However, pathways that leverage existing gas networks to deliver decarbonized fuels in combination with electrification solutions represent the least costly pathways to achieving building sector decarbonization.

Background and New England Regional Overview

Local, state and provincial, and federal levels of government across North America have set aggressive economy-wide climate and clean energy goals. Developing more recently are economy-wide targets that focus not only on the power sector, but on emissions from industrial, building (residential and commercial), and transportation sectors, as well.[7] Within the U.S., 24 states have set these economy-wide targets where each target and emissions baseline year are specific to the needs of each state.[8] Within industrial and building sectors, several state and local governments have evaluated pathways to decarbonization with some developing processes that evaluate the role of both electricity and gas for LDCs in reaching net-zero emissions targets.[9]

In many New England states, decarbonization discussions have focused on the need to transition building (residential and commercial) and industrial sectors to electrified solutions with a limited role for current thermal energy providers like LDCs, see Table 2. While many of these policy and planning efforts are in the early stages, the need to evaluate the role of both existing power sector and gas providers in transitioning to a path towards net-zero climate goals will be critical in developing a safe, reliable, equitable and cost-effective energy future.

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[7] Center for Climate and Energy Solutions, State Climate Policy Maps, Available at https://www.c2es.org/content/state-climate-policy/.
[8] Ibid.
[9] On October 29, 2020, the Massachusetts Department of Public Utilities issued an order opening an investigation (DPU 20-80) into the role of LDCs in the Commonwealth's goal to achieve net zero emissions by 2050. On May 12, 2022, the New York State Public Service Commission adopted gas planning procedures requiring natural gas utilities to submit plans that comply with the State's greenhouse gas emission reduction goals.

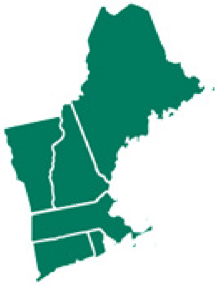
Table 2: Key Climate and Clean Energy Policies in New England

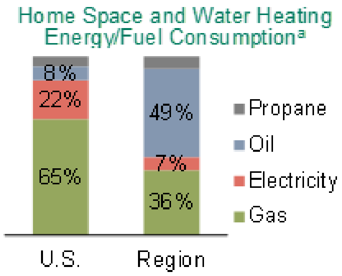
State	GHG Emissions Reduction Targets	Renewable Energy Standards and Mandates (% of retail elec. sales)	Key Policies and Proceedings
Connecticut	An Act Concerning Climate Change Planning and Resiliency (2018): interim target of 45% below 2001 levels by 2030 and 80% by 2050 (set in 2008).	40% of renewable energy by 2030. Department of Energy and Environmental Protection released an RFP in 2019 seeking up to 2,000 MW of wind by 2030.	No new policies or current proceedings.
Maine	Act to Promote Clean Energy Jobs and To Establish the Maine Climate Council (2019): 45% below 1990 levels by 2030 and 80% by 2050, with a goal of achieving net zero by 2050.	80% renewable energy by 2030 and 100% by 2050.	No current proceedings.
Massachusetts	Global Warming Solutions Act (2008): 80% below 1990 levels by 2050.	15% renewable energy by 2020 and +1% each year after; and Clean Standard of 16% by 2018 increasing to 80% by 2050. An Act Driving Clean Energy and Offshore Wind (2022) increased the procurement mandate to 5,600 MW by 2030.	Massachusetts Clean Heat Standard: developing a high-level program to meet the emissions limit for residential, commercial, and industrial heating in the state. MA Future of Gas proceeding (20-80)
New Hampshire	Climate Action Plan (2009): 80% below 1990 levels by 2050.	25.2% renewable energy by 2025.	No current proceedings.
Rhode Island	Act on Climate (2021): 45% below 1990 levels by 2030, 80% by 2040, and net zero by 2050.	38.5% renewable energy by 2035. Amendments to the Affordable Clean Energy Security Act required an RFP for 600 to 1,000 MW of wind to be issued by October 15, 2022.	Investigation Into the Future of the Regulated Gas Distribution Business: To examine the extent of the requirements of the Act on Climate impact the conduct, regulation, ratemaking, and the future of gas and gas distribution.
Vermont	An Act Relating to Addressing Climate Change (2020): 26% below 2005 levels by 2025, 40% by 2030, and 80% by 2050.	55% renewable energy by 2017 and +4% every 3 years until 75% by 2032.	Clean Heat Standard passed legislature.

New England has unique characteristics that present important considerations for rapid decarbonization:

Building Stock

Most residential and commercial buildings were built before 1990, with a significant portion of buildings constructed prior to 1940. An older existing building stock provides opportunities to improve building envelope energy efficiency, however, deep energy efficiency retrofits may not be technologically feasible or cost effective.



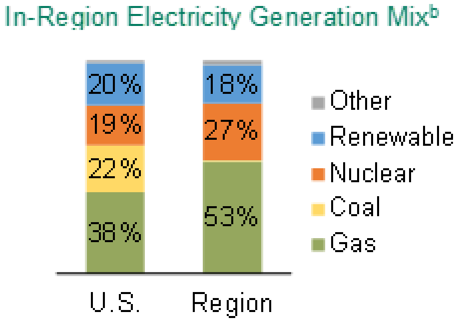


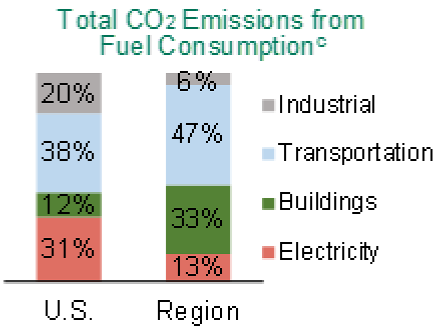
Building Sector

New England is a cold climate region where fuel oil is the dominant energy source for residential and commercial space and water heating, making New England unique from other regions. This study is focused on the transition of the existing natural gas load, which currently is 36 percent of residential space and water heating energy consumption with electricity accounting for 7 percent.

Power Sector

The New England electricity generation mix is predominantly natural gas, nuclear, and renewables (53 percent, 26 percent, and 18 percent, respectively). In recent years, electricity demand is met with increased generation from natural gas-fired plants and growth in new renewable generation. A low carbon transition will require emissions reductions from the current electricity mix, while adding more zero-emitting capacity to the system as demand increases due to electrification of end-uses.





Carbon Dioxide Emissions

Fuel use in residential and commercial buildings result in a greater share of emissions in New England compared to the U.S. due to greater reliance on fuel oil, a higher-emitting fuel when combusted compared to natural gas. Natural gas accounts for nearly all emissions from the New England power sector, while combusting this fuel accounts for roughly 40 percent of emissions from use in buildings.

Data Sources
a. EIA Residential Energy Consumption Survey, Annual household site end-use consumption by fuel, 2015 Survey Data.
b. EIA Electricity Data Browser, Net Generation for All Sectors, 2021 data.
c. EIA Energy-Related State CO2 Emissions, 2019 data.

Analysis Methodology

Scenarios Analyzed

The analysis considers the three key scenarios described in Table 3. The Reference scenario represents business as usual natural gas usage for the buildings sector, while the three decarbonization scenarios achieve carbon-neutrality with greater than 90 percent reductions in carbon dioxide (CO_2) emissions from 2021 levels.[10]

Table 3: Modeled Scenarios

Scenario	Description
Reference	Business as usual projection of current energy system; Does not achieve economy-wide carbon neutrality by 2050.
High Electrification	High levels of electrification; Represents a future with rapid electrification coupled with decarbonization of the electricity sector and end-use energy efficiency.
High Fuels	High levels of decarbonized fuels; Represents a future that continues to rely completely on the existing natural gas infrastructure to deliver decarbonized fuels and incorporates end-use energy efficiency, without equipment electrification.
Hybrid	Hybrid or dual-fuel approach; Represents a mix of the above scenarios with moderate levels of electrification, decarbonized fuels, end-use energy efficiency, and a continuing role for distribution networks.

An integrated set of ERM analytical tools were used to assess potential future decarbonization paths for natural gas LDCs. These tools consider the impact of different reduction strategies on current gas customers and on the utility business model.

Modeling Approach

Below is a brief overview of the analytical approach. See Appendix A for a more detailed discussion of the analytical assumptions and methodology. Table 4 illustrates the key inputs and outputs of the scenario modeling.

Table 4: Scenario Modeling – Key Inputs and Outputs

Key Inputs	Key Outputs
■ Regional customer natural gas demand ■ Heating equipment costs and efficiency improvements ■ Gaseous fuel commodity costs for conventional natural gas, renewable natural gas, clean hydrogen, and methanated hydrogen as power to gas to create synthetic natural gas ■ Electric generation capacity costs and transmission & distribution costs for incremental capacity additions	■ Carbon dioxide emissions associated with buildings sector natural gas use ■ Energy demand by type: conventional natural gas, alternative fuels, and electricity ■ Total costs for decarbonizing buildings sector natural gas use (costs for natural gas service, energy efficiency, end use appliances, electric system and electricity)

[10] The scope of this study is focused on the transition of the current load of the natural gas system from use in buildings, excluding gas used to power large electric generating facilities. To achieve carbon neutrality in 2050 for this scope, remaining emissions are assumed to be addressed through carbon removal and/or carbon capture.

Inflation Reduction Act Considerations

On August 16, 2022, President Biden signed into law the Inflation Reduction Act (IRA), a legislative package with key provisions focused on reducing energy costs and addressing climate change. This study works to incorporate economic impacts from relevant changes from this Act, though actual implementation of the IRA in the future may differ from the assumptions outlined here. The resulting effect of this legislation in reducing costs for clean energy projects and new technologies will be an important driver for decarbonizing gas networks.

Key IRA provisions incorporated into this scenario analysis include supply-side credits for zero-emitting renewable electricity as well as for renewable natural gas and hydrogen. Demand-side incentives are also captured as reducing the costs of heat pumps. See Appendix A for more detail.

Analysis Results

Analysis Scope

The scope of this study is focused on reducing emissions associated with existing natural gas demand from the building sector. Scenarios include a range of fuels and end use equipment deployments to analyze the impacts on energy demand, emission reductions, and electric and gas network costs in 2050.

DSI members recognize that the efforts of LDCs to decarbonize are not necessarily utility-specific, differing from the illustrative paths discussed here and are part of a wider decarbonization effort across the economy.

Reducing end-use emissions from the combustion of natural gas relies on several reduction strategies, including:

- Reducing energy demand,
- Meeting energy demand with low- and zero-carbon alternatives,
- Switching demand to other low-carbon energy sources, and
- Capturing emissions.[11]

This study's decarbonization paths for New England natural gas LDCs rely on the first three strategies. The scenarios constructed—Hybrid, High Fuels, and High Electrification—deploy these strategies in different configurations while exploring a range of challenges and costs posed by each path. See Table 3 for a detailed description of each scenario.

Key Findings

New England's cold-weather climate presents significant challenges to decarbonization of natural gas end-uses for thermal use in residential, commercial, and industrial sectors; the most significant of the challenges may be that of building heat. Most of the following findings are related to strategies for addressing this primary challenge, they include:

- Energy efficiency (building envelope and appliance efficiency) is a highly cost-effective decarbonization measure, though there are limitations to the savings that can be achieved,[12]
- Low-carbon fuels are an effective and scalable strategy when employed for hard-to-electrify uses like winter peak heating demand and industrial processes,
- The cost of meeting winter heating peak is the biggest cost differentiator between a full electrification path and one that uses a hybrid (dual fuel) strategy for building heat, and
- Decarbonization pathways that rapidly migrate customers from LDC systems pose significant cost risks to customers who might be slower to or cannot covert.

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[11] This strategy is not analyzed as part of this study. Although carbon capture, utilization, and storage (CCUS) is a potentially viable strategy, its usage and costs are less well understood than those of the other strategies and is not expected to be a viable strategy for the most residential and commercial gas demand.

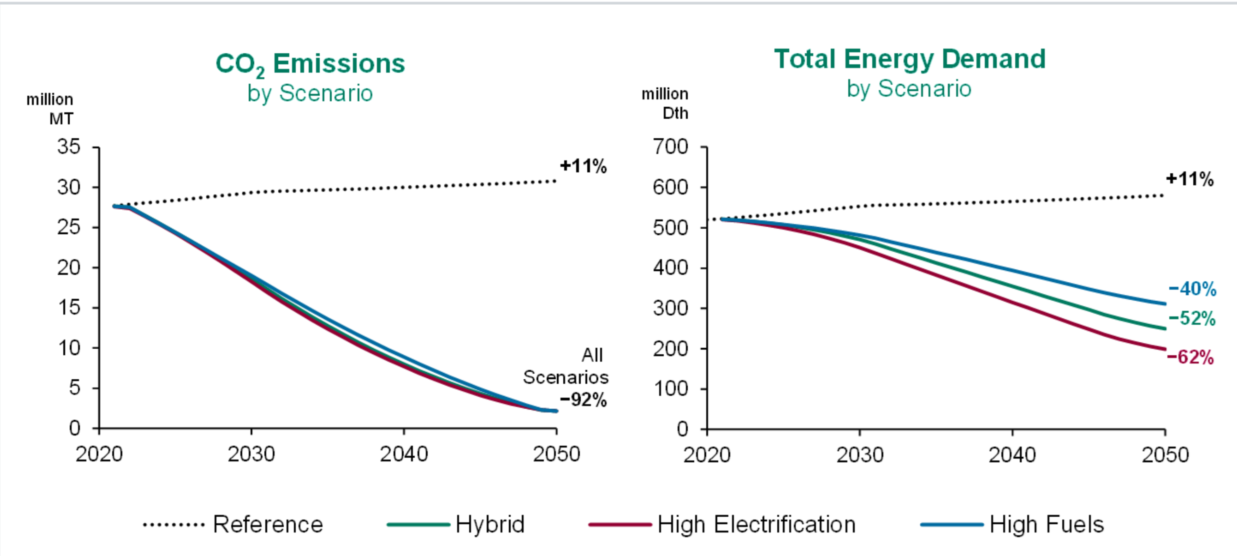
[12] The study distinguishes buildings from appliances, and not all appliance efficiency can be said to be "highly cost-effective."

The Long Term Vision analysis' three decarbonization scenarios assess the GHG emission trajectories of the residential, commercial, and industrial sectors for natural gas demand. The High Electrification and High Fuels scenarios examine decarbonization paths that rely heavily on a single strategy: fuel switching in the case of High Electrification and low-carbon alternatives in High Fuels. **The Hybrid scenario, DSI's recommended path for the New England region, balances the two strategies.** This balancing of strategies represents an optimization of both cost and feasibility and results in a strategy that could have greater success, fewer implementation challenges, and be deployed with lower overall costs than the other two scenarios.

Emissions and Total Energy

Each scenario is constructed to follow a similar emissions reduction trajectory. All of the scenarios exceed 90 percent emissions reduction by 2050 (Figure 1), a target that is roughly consistent with a 1.5º Celsius path. The emission reduction in each scenario results from a decrease in delivered fossil natural gas. Each scenario has approximately the same amount of residual fossil gas delivered in 2050. By contrast, the Reference scenario that includes no GHG mitigation efforts grow end-use emissions with gas demand, increasing 11 percent by 2050.

Figure 1: Total Emission and Energy Demand by Scenario, 2020-2050



Although the emissions trajectory is the same for each scenario, the total energy demand varies across each path (Figure 1). The variation depends on the type of end-use equipment (primarily residential and commercial space heating) that is part of a scenario's decarbonization approach (see Change in Energy Demand below).

Change in Energy Demand

Energy demand reduction in each scenario is driven by two main elements: building efficiency measures and end-use appliance efficiency. Figure 2 and its accompanying chart show the contribution of each element across the decarbonization scenarios.

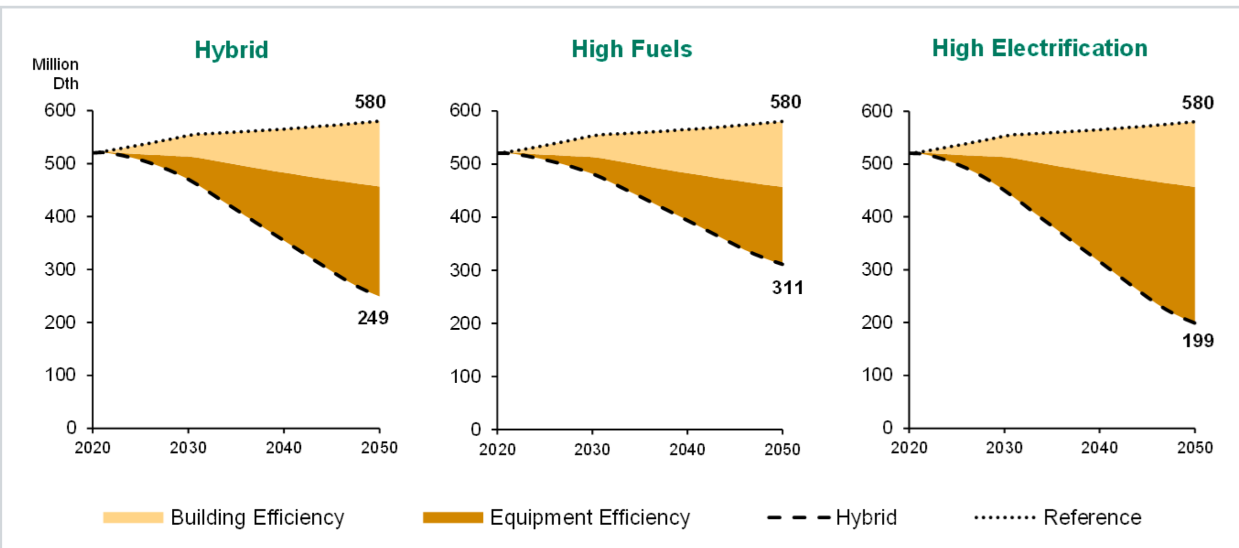
Building efficiency, which includes a range of measures that decrease building energy use for both heating and cooling, is a foundational strategy. Building efficiency, however, is constrained by the building stock itself and by feasibility, practicality, and cost issues that limit how much can be deployed. All scenarios incorporate the same level of ambition for building efficiency.

End-use appliance efficiency energy demand reductions result from the conversion from conventional gas-fired heating equipment to a range of electric heat pump technologies that have significantly higher efficiencies, including air source heat pumps and ground source heat pumps (GSHP). The differences among the scenarios in the energy demand reduction from equipment efficiency depends on the mix of conversion technologies applied.[13]

The High Electrification scenario, because it replaces a larger portion of demand with high efficiency electrical appliances, achieves the greatest reduction in energy demand (approximately 60 percent compared to 2021 levels). The High Fuels scenario reduces demand the least, about 40 percent, while the Hybrid scenario reduces demand roughly midway between the other two decarbonization scenarios, about 50 percent.

In Figure 2, change in energy demand for each scenario is compared to the demand for fossil natural gas in the Reference scenario (dotted line at the top). In each of the figures below, the black dotted line represents the Reference scenario energy demand, which increases from 522 million Dth in 2021 to 580 in 2050.[14] The black dashed line represents the energy demand trajectory under each decarbonization scenario. In the Hybrid scenario, energy demand declines to 249 million Dth; High Fuels demand declines to 311 million Dth; and High Electrification declines to 199 million Dth.

Figure 2: Change in Energy Demand, 2020-2050



Change in Energy Demand by 2050

Million Dth	Hybrid	High Fuels	High Electrification	Reference
Building Efficiency Reductions	-123	-123	-123	NA
Equipment Efficiency Reductions	-208	-146	-258	NA
Total Energy Demand in 2050	**249**	**311**	**199**	**580**

[13] The current fleet-wide efficiency of conventional gas-fired heating units in New England is estimated at 82% and is the baseline for the analysis. New high-efficiency conventional gas-fired heating equipment is roughly 95% efficient (in the analysis this efficiency grow over time to 98%). The heat pump technologies to which gas customers are converted over time in each scenario range from starting values of 130% for gas heat pumps (GHPs), 300% for air-source heat pumps (ASHPs), and 450% for ground-source heat pumps. (Useful thermal output from heat pump technologies can exceed the energy input because the delivered heat is not directly supplied by the fuel, but rather the fuel is used to extract heat from an environmental source, either air or water.)

[14] Growth in Reference reflects current historical trend through 2030, then slows to a long-run growth rate tied to historical population and housing trends. See Appendix A. Assumptions and Methodology for a discussion.

Energy Supply by Fuel Type

Once reduction in energy demand has been accounted for, the next component of each scenario is the mix of fuels (gases and electricity) to meet demand, Figure 3. The energy mix in each scenario is comprised of electricity, renewable natural gas (RNG), two forms of green-hydrogen-based gases, and a residual amount of fossil natural gas.

The hydrogen-based gases are pure hydrogen (H2) and methanated hydrogen (P2G) and the analysis limits the amount of pure hydrogen blending in each scenario to 16 percent.[15] Methanated hydrogen is green hydrogen that has been converted to methane through the addition of CO_2. Since it behaves like fossil natural gas, methanated hydrogen can be blended into LDC distribution systems without the restrictions associated with pure hydrogen. As equipment and demand change over time, fuels are added to the energy supply in the model based on relative price, available supply, and blending restrictions.

As shown in Figure 3, the Hybrid scenario uses a more diverse mix of fuels than the other scenarios. This fuel diversity is among the many elements making the Hybrid scenario attractive. A diverse approach to decarbonized fuels achieves several desirable ends. First, it can encourage the parallel development of a range of decarbonized fuels over time. Second, it can adapt to a range of outcomes in the evolutionary path of those decarbonized fuels. Third, the strategy can use those decarbonized fuels at levels which may pose fewer stresses on all sources of supply. The High Fuels scenario, for instance, exhausts the estimated available renewable natural gas (RNG) supply to New England (based on proportional demand from Eastern U.S. sources) and must add greater amounts of hydrogen-based fuels.

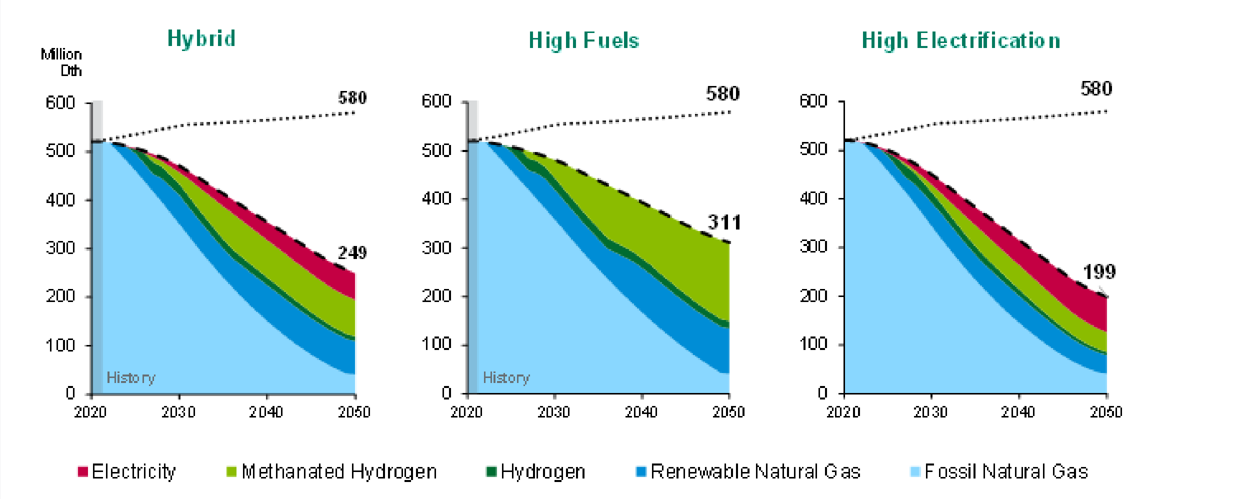
The High Fuels scenario uses the largest amount of gases to fulfill demand at 311 million Dth in 2050, a reduction of 46 percent from 2021 throughput levels. The Hybrid scenario reduces gas throughput by 57 percent to 249 million Dth and High Electrification's gas throughput is reduced 66 percent to 199 million Dth.

Heating Equipment Evolution

In each of the decarbonization scenarios, the addition of new conventional gas-fired heating appliances are slowly phased out through 2030. From 2030 onward, only new high-efficiency electric and gas heat pumps are added at the natural replacement cycle, assuming an average 25-year useful life. The exception is that of ASHPs in the Hybrid scenario, which are added as part of a dual-fuel system in combination with the existing conventional gas-fired appliances remaining in operation.

[15] 16% volumetric basis, which is equivalent to 5% on a heat content basis.

Figure 3: Energy Supply by Fuel, 2020-2050



Energy Supply by Fuel in 2050

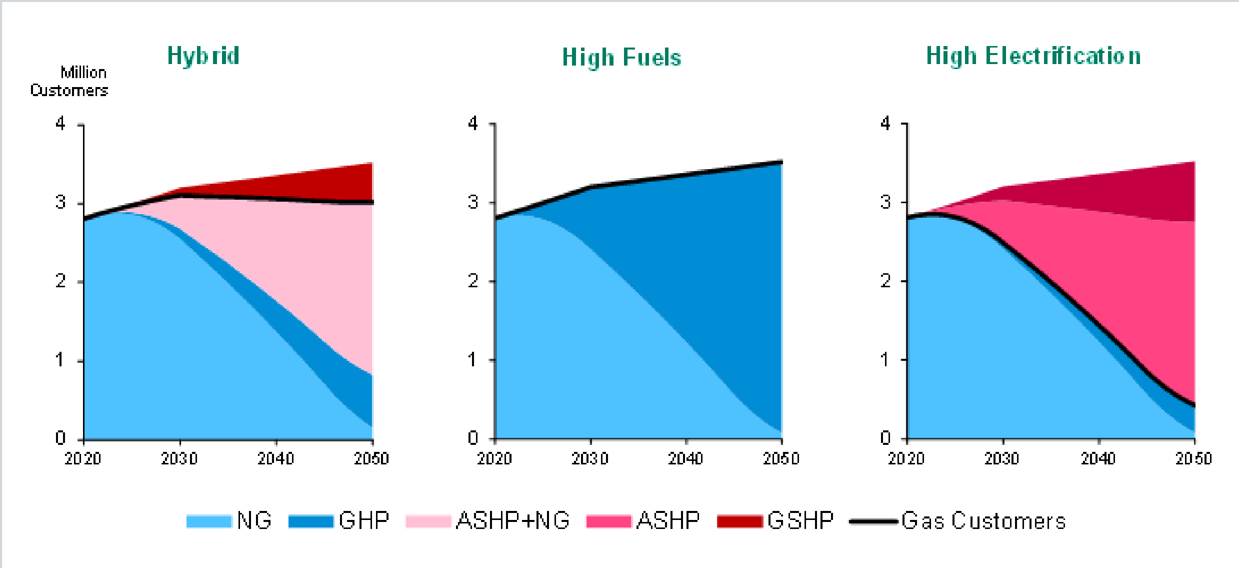
Million Dth	Hybrid	High Fuels	High Electrification	Reference
Fossil Natural Gas (NG)	41 (16%)	41 (13%)	41 (20%)	580 (100%)
Renewable Natural Gas (RNG)	69 (27%)	94 (30%)	38 (19%)	NA (0%)
Hydrogen (H2)	10 (4%)	16 (5%)	6 (3%)	NA (0%)
Methanated Hydrogen (P2G)	75 (30%)	161 (52%)	40 (20%)	NA (0%)
Total Gases (Throughput)	**194** (78%)	**311** (100%)	**125** (63%)	**580** (100%)
Electricity (Btu basis)	55 (22%)	- (0%)	74 (37%)	NA (0%)
Total Energy Demand, 2050 (Btu basis)	**249** (100%)	**311** (100%)	**199** (100%)	**580** (100%)
Electricity (million MWh)	16	-	22	NA

Figure 4 shows the evolution of heating equipment across scenarios. The light blue color (NG) represents the fleet of conventional natural gas-fired equipment; its trajectory is the same in each scenario as it is driven by the natural replacement cycle.

Each decarbonization scenario employs a different mix of equipment types. The type of equipment to which customers are converted and how it is used in the case of dual-fuel heating in the Hybrid scenario, determines whether they remain as gas customers of the LDC or migrate fully away from gas use.

The New England residential, commercial, and industrial gas customer base in the Reference scenario grows from 2.8 million customers to 3.5 million customers (23 percent by 2050 or 0.7 percent per year). The High Fuels scenario converts all customers to gas heat pumps and retains all the customers projected in the Reference scenario as gas customers. In the Hybrid scenario, the customer base grows modestly (six percent from 2021 to 2050, 0.2 percent per year); 17 percent of 2050's projected customers have migrated away from the gas system. In High Electrification, the residential and commercial customer base has declined 85 percent by 2050, leaving only a small residual number of customers on the system. The High Electrification scenario converts only a small number of customers to gas heat pumps, 10 percent of new equipment conversions. Most customers in the High Electrification scenario convert to fully electrified heating, approximately 66 percent ASHP and approximately 23 percent GSHP. These fully electrified customers migrate completely away from the gas system by 2050.

Figure 4: Residential & Commercial Customers by Heating Equipment Type, 2020-2050



Customer Counts by Heating Equipment Type in 2050

Million Dth	Hybrid	High Fuels	High Electrification	Reference
Conventional Natural Gas (NG)	0.2 (6%)	0.1 (4%)	0.1 (4%)	3.5 (100%)
Gas Heat Pump (GHP)	0.7 (19%)	3.4 (96%)	0.3 (10%)	NA (0%)
Hybrid Heating (ASHP+NG)	2.2 (61%)	NA (0%)	NA (0%)	NA (0%)
Total Gas Customers	**3.0** (86%)	**3.5** (100%)	**0.5** (13%)	**3.5** (100%)
Air Source Heat Pump (ASHP)	NA (0%)	NA (0%)	2.3 (65%)	NA (0%)
Ground Source Heat Pump (GSHP)	0.5 (14%)	NA (0%)	0.8 (22%)	NA (0%)
Total Customers (including migrated)	**3.5** (100%)	**3.5** (100%)	**3.5** (100%)	**3.5** (100%)

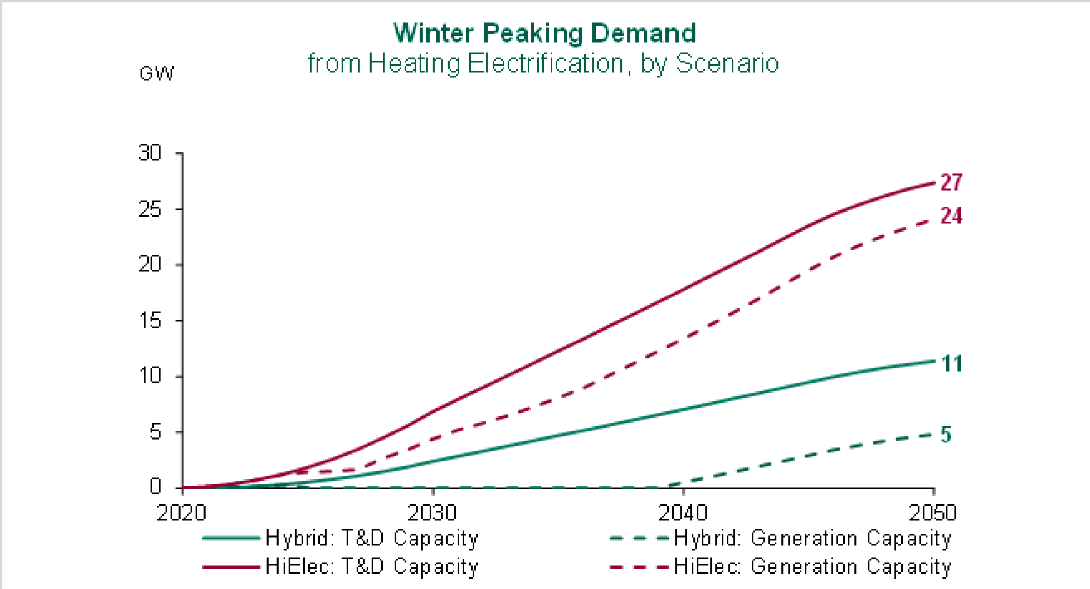
Considering that the Hybrid scenario's primary conversion strategy is dual-fuel—adding ASHPs to existing gas-fired heating—all customers who adopt the dual fuel (ASHP+NG) remain as gas customers. In a dual-fuel configuration, the ASHP is used when outdoor temperatures are above 20ºF and the gas-fired conventional heating is used at 20ºF and below. A dual-fuel strategy uses electrified heating in its most efficient range and relies on the gas-fired heating at temperatures in which air-source heat pumps rapidly lose efficiency.

Electric Peak Demand from Building Heat

The high-efficiency of electricity-based heat pumps can significantly reduce energy demand while also converting the demand for fossil natural gas to an energy source that has been steadily decarbonizing with the rapid growth of renewable energy sources. However, in cold-weather climates, ASHPs can create significant peak demand for electricity during the coldest hours and days of the heating season. The efficiency of air source heat pumps, even those designed for cold climates, rapidly lose efficiency as temperatures decline below freezing. To fully electrify a home or business might require significant oversizing of the system and/or a reliance on an electric resistance back-up heating system to ensure sufficient space heating output in the coldest temperatures.[16]

[16] Because ground source heat pumps work from a constant-temperature liquid, they operate at much higher efficiencies across the heating and cooling seasons and do not have the same cold temperature efficiency decline as air source heat pumps.

Figure 5: Incremental Peak Demand from Building Heat Electrification, 2020-2050



Incremental Peak Demand from Building Heat Electrification, 2050

GW	Hybrid	High Fuels	High Electrification	Reference
Total Electric Winter Peak Demand (from ASHPs and GSHPs)	11	NA	27	NA
Hydrogen Production Generation Capacity Available (to meet winter peak demand)	7	13	3	NA
Net Electric Generation Capacity Winter Peak Demand (net of Hydrogen Production Capacity)	**5**	NA	**24**	NA
Electric Transmission & Distribution (T&D) Winter Peak Demand (same as Total)	**11**	NA	**27**	NA

Hydrogen and Methanated Hydrogen Production:

Million Dth				
Hydrogen (H2)	10	16	6	NA
Methanated Hydrogen (P2G)	75	161	40	NA

This analysis assesses the peak demand from electrified heating in the two scenarios (Hybrid and High Electrification) that employ electricity-based heat pumps. Below, Figure 5 shows the total estimated peak demand from electrified heating through 2050. Peak demand steadily rises over time as the number of electricity-based heat pumps increases. In the High Electrification scenario, the peak demand for electricity is estimated to reach 27 GW by 2050. The Hybrid scenario, however, creates less than half the peak demand by 2050 and is estimated to reach 11 GW. Both scenarios have comparable levels of air source heat pumps, with the number of ASHPs in High Electrification only six percent larger than that in Hybrid.

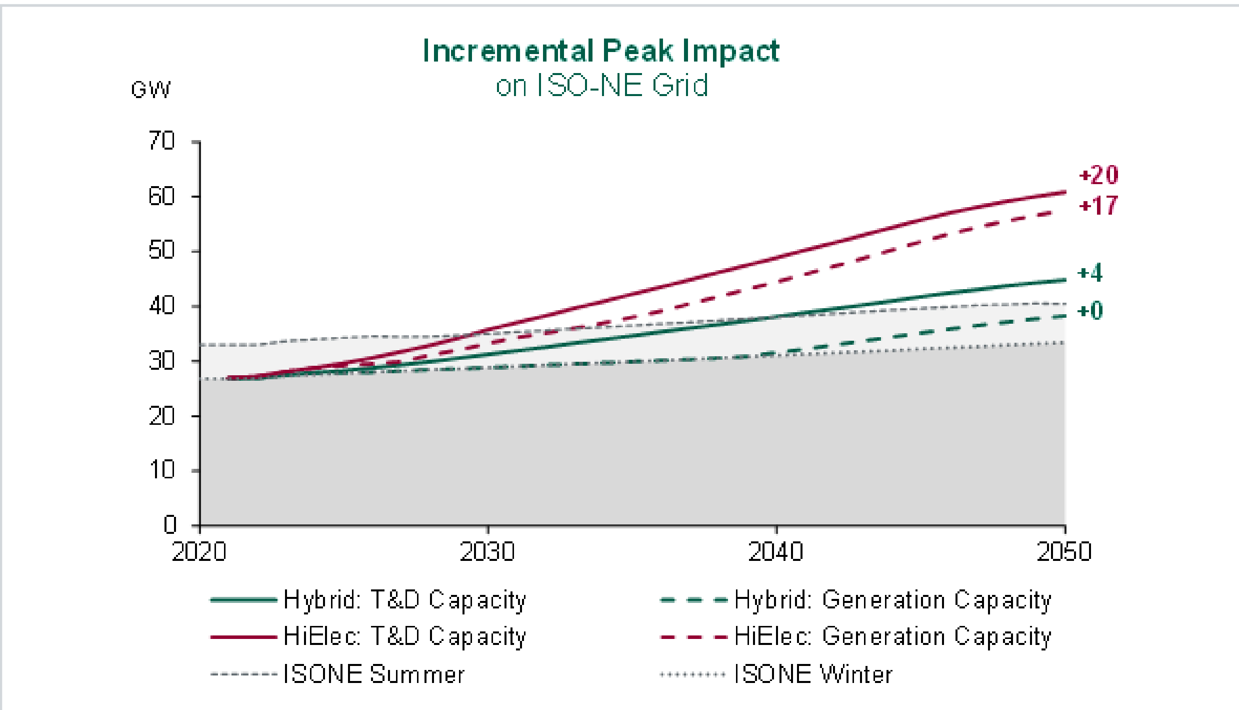
Two main factors create the difference in peak energy demand between the High Electrification and the Hybrid scenarios. The first factor is the coldest temperature in which air source heat pumps are designed to operate. In the High Electrification scenario, the ASHPs must supply space heating through the entire winter season. In the Hybrid scenario, ASHPs operate down to 20º Fahrenheit, and gas-fired heating operates at temperatures below 20ºF. The second factor is the rapidly declining efficiencies of ASHPs in the coldest of weather means that in High Electrification, ASHPs have their highest Btu per hour output when they are operating at their lowest efficiency. **These two factors drive the winter peak demand for electricity in the High Electrification scenario to be more than double that of the Hybrid scenario.**

To accommodate an increase in peak electric demand, the electric grid will require an increase in generation capacity, additional transmission to interconnect generation capacity, and upgrades to the distribution system to deliver increased electricity to end-use customers during periods of peak demand; further increasing costs to consumers.

The ISO New England (ISO-NE) grid is currently a summer peaking system designed to accommodate nearly 34 gigawatts (GW) of demand; peak demand is largely driven by air conditioning (Figure 6). Winter peak on the ISO-NE grid is estimated at roughly 27 GW. As a result of this gap between current winter peak and the designed projected peak load, roughly six to seven GW of winter peaking demand could potentially be added to the system before additional generation capacity and/or T&D system upgrades would be required.

The accumulation of new winter peak demand in the High Electrification scenario, seen around 2030, pushes the winter peak higher than that of ISO-NE's summer's projected peak capacity. In the Hybrid scenario, the 34

Figure 6: Impact of Incremental Peak Demand on ISO-NE Grid, 2020-2050



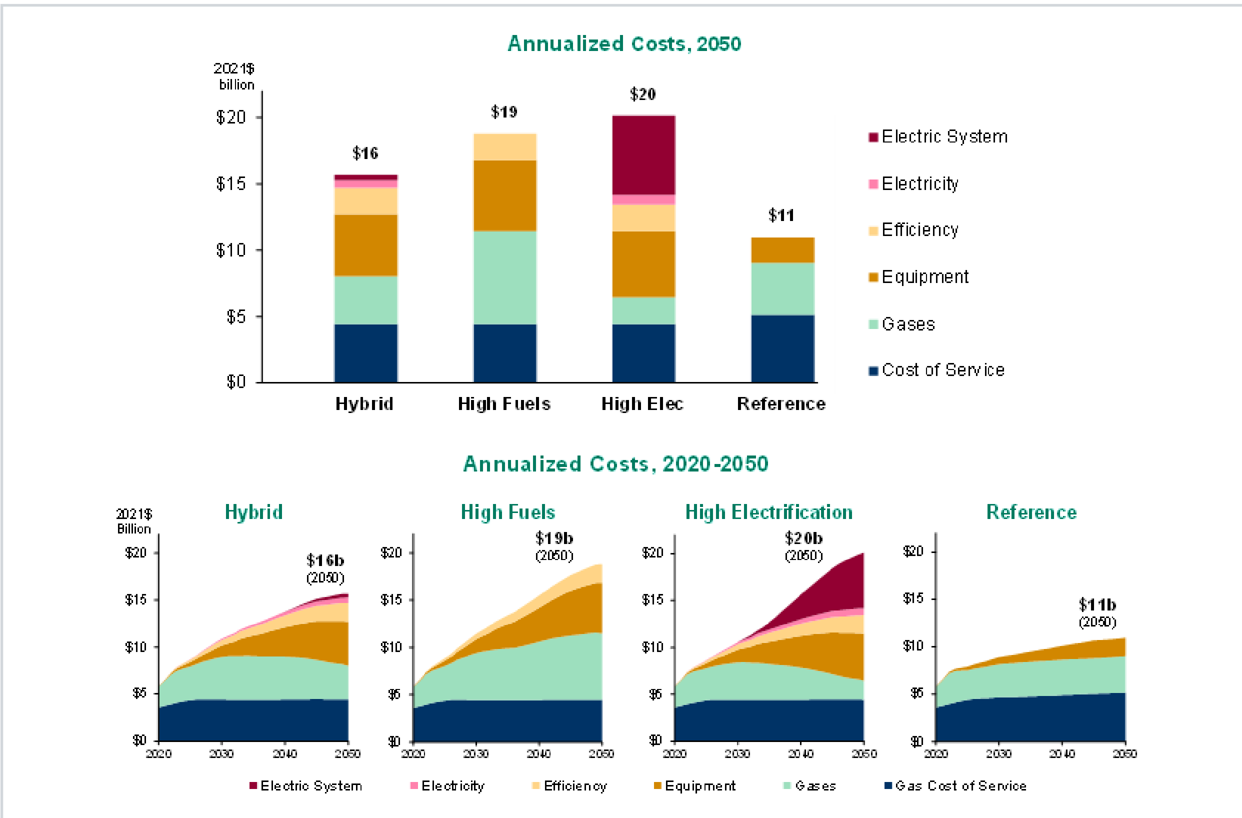
Impact of Incremental Peak Demand on ISO NE Grid, 2050

GW	Hybrid	High Fuels	High Electrification	Reference
ISO-NI Winter Peak Demand (before heating electrification peak demand)	33	NA	33	NA
ISO-NI Summer Peak Demand (adjusted for solar capacity availability)	40	NA	40	NA
ISO-NI Summer Peak Capacity Available for Winter Peaking	7	NA	7	NA
Net Electric Generation Capacity Winter Peak Demand (net of Hydrogen Production Capacity)	5	NA	25	NA
Electric Transmission & Distribution (T&D) Winter Peak Demand (same as Total)	12	NA	28	NA
Winter Peak Generation Capacity Required	-	NA	**+17**	NA
Winter Peak T&D Capacity Required	**+4**	NA	**+20**	NA

GW of projected summer peak does not occur until about 2040. The High Electrification scenario is estimated to require 20 GW of new T&D capacity and 17 GW of incremental peak generation capacity to meet the new winter peak created by electrified heating. The Hybrid scenario is estimated to require only four GW of new T&D capacity and no additional generation capacity (beyond that used for hydrogen production) to meet its winter peaking demand from electrified heating.

For the purposes of assessing the potential costs of the decarbonization scenarios, this analysis assumes that the new generation capacity used to meet demand is comprised of a mix of the best available renewable resources for New England (largely offshore wind) and storage to help balance those resources.[17,18]

Figure 7: Total Costs by Scenario, 2050 and 2020-2050



Total Annualized Costs in 2050

2021$, Billions	Hybrid	High Fuels	High Electrification	Reference
Electric System (Generation/T&D Capacity)	$0.4	$0.0	$5.9	NA
Electricity (Commodity)	$0.5	$0.0	$0.7	NA
Efficiency (Building)	$2.0	$2.0	$2.0	NA
Equipment (Heating)	$4.7	$5.4	$5.0	$1.9
Gases (Commodity)	$3.6	$7.0	$2.0	$3.9
Cost of Service	$4.4	$4.4	$4.4	$5.1
Total Annualized Cost, 2050	**$15.7**	**$18.8**	**$20.1**	**$11.0**

[17] Because this study is tightly focused on the efforts that natural gas utilities can take to decarbonize the energy they sell to customers, a full economic dispatch optimization analysis of the New England grid was outside the scope of the analysis.

[18] Most electric grids currently rely on a probabilistic assessment of variable (renewable) resource availability for peak demand and assign a capacity value to nominal (nameplate) capacities in forecasting the ability of the grid to meet peak demand. For ISO-NE, offshore wind's capacity value in the winter is 60 percent of nameplate and onshore wind's is 28 percent, which means that 167 MW of offshore wind is required to meet 100 MW of projected peak demand in the ISO-NE projections, while 357 MW of onshore wind is required to meet 100 MW of peak demand.

Comparison of Costs by Scenario

Costs for each of the scenarios have been projected on an annualized basis that equates to the annual revenue requirement utilities establish in a regulated rate case. In addition to aligning with ratemaking processes, the annualization of the analysis's projected costs also allows costs to be associated with the energy delivered and the energy and emissions reduced each year (see Cost Per Metric Ton of Emissions Reduction). Although the direct effect of each scenario's costs may not fully be borne by individual rate payers, as incentives and other mechanisms could spread costs more broadly, the cost projections in this analysis are designed to represent the full economic impact of each scenario. Figure 7 compares each of the scenarios' annual costs in 2050 and the annualized costs for each of the scenarios from 2020 to 2050.

Cost projections in the analysis are broken down into the following categories:

- **Electric System**: the costs associated with the electric generation capacity and T&D upgrades required to meet the winter peak demand for electricity from electrified heating,
- **Electricity (commodity)**: the cost of renewable electricity used by electric heat pumps,
- **Efficiency (Building):** the cost of efficiency measures (building envelope, etc.) that reduce the heating and cooling energy needs of a building,
- **Equipment (Heating):** the costs for new heating equipment added in each scenario as existing heating equipment is retired and replaced,
- **Gases (commodity):** the total cost of all gases supplied to customers, including RNG, H2, methenated hydrogen, and residual fossil natural gas, and
- **Cost of Service:** the cost to operate and maintain the gas distribution systems of New England's LDCs.

Each of the decarbonization scenarios costs more than the Reference scenario, which has a projected cost of just over $11 billion in annualized costs. The Hybrid scenario is projected to be the least-cost decarbonization path, incurring just under $16 billion in annualized costs in 2050, 42 percent higher than those projected for the Reference scenario in that year. The High Fuels scenario is projected to cost just under $19 billion annually by 2050, a cost premium to the Reference scenario of 71 percent, and the High Electrification scenario is projected to cost over $20 billion in annualized costs, 84 percent greater than the Reference scenario.

The cost of high efficiency heat pumps and efficiency measures in the decarbonization scenarios are largely responsible for the cost gap between the Reference scenario and the decarbonization scenarios. The three decarbonization scenarios employ the same level of energy efficiency at the same cost and assume only small differences in equipment costs form the mix of equipment types for each scenario.

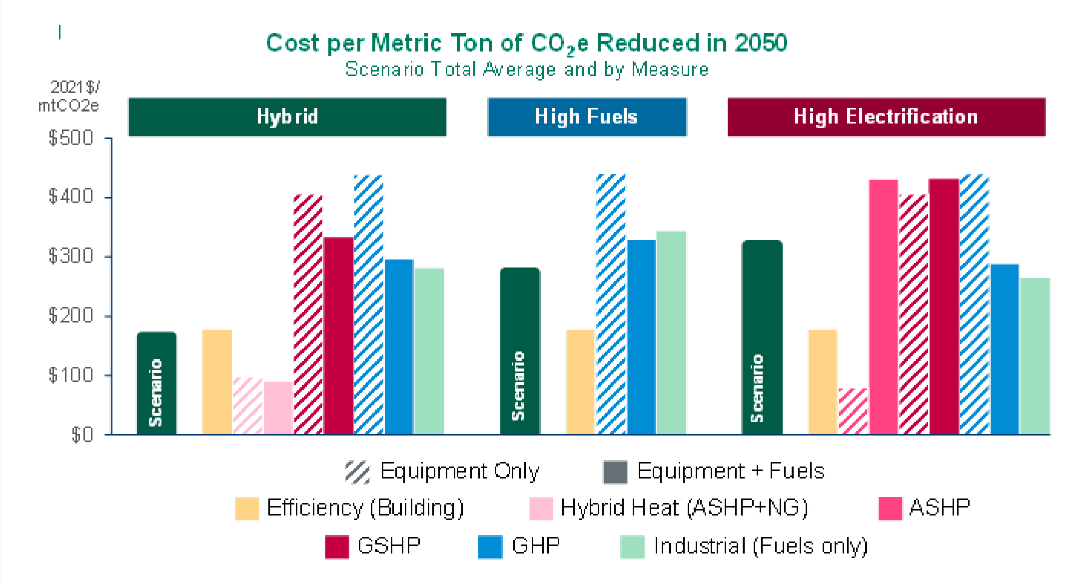
The High Electrification scenario costs are driven primarily by the winter electric peak demand impacts, and the associated build out of the electric grid and generating capacity. Conversely, the cost of meeting winter electric peak in the Hybrid scenario is far lower because meeting the peak demand for heating is borne by the existing gas distribution system which is already designed to serve such a load.

While the High Fuels scenario has no costs associated with winter electric peak, its extreme demand for decarbonized fuels results in the need to include the highest costs associated with utilizing all the available RNG. Once the RNG supply is exhausted, the scenario will then use much higher levels of green hydrogen-based fuels. These fuels, incentivized by the IRA through the 2030s, are a cost-effective solution during that time period and bring down the total cost of the High Fuels scenario roughly 15 percent. Without the available IRA tax incentives, the High Fuels scenario would be the highest cost scenario.

Cost Per Metric Ton of Emissions Reduction

Figure 8 shows each decarbonization scenario's costs on a per metric ton of CO_2 equivalent ($mtCO_2e$) reduced.[19] When considered through the lens of incremental costs rather than total costs, the differences among the decarbonization scenarios are magnified: The High Electrification scenario is nearly double the incremental cost of the Hybrid scenario, and the High Fuels scenario is two-thirds more costly on an incremental basis than the Hybrid scenario. On a per metric ton of CO_2e reduced basis, the full Hybrid scenario is \$164, High Fuels is \$273, and High Electrification is \$320 per $mtCO_2e$ reduced.

Figure 8: Cost of Emission Reductions



Cost of Emission Reductions in 2050 (per Metric Ton fo CO_2)

2021\$ / $mtCO_2e$	Hybrid	High Fuels	High Electrification
Average for Scenario	**\$165**	**\$273**	**\$320**
Efficiency (Building)	\$178	\$178	\$178
ASHP	*ASHP+NG*		*ASHP only*
Equipment Only	\$98	NA	\$80
Equipment+ Fuels	\$91	NA	\$431
GSHP			
Equipment Only	\$406	NA	\$406
Equipment+ Fuels	\$333	NA	\$431
GHP			
Equipment Only	\$439	\$441	\$440
Equipment+ Fuels	\$296	\$330	\$289
Industrial (Fuels only)	\$281	\$343	\$264

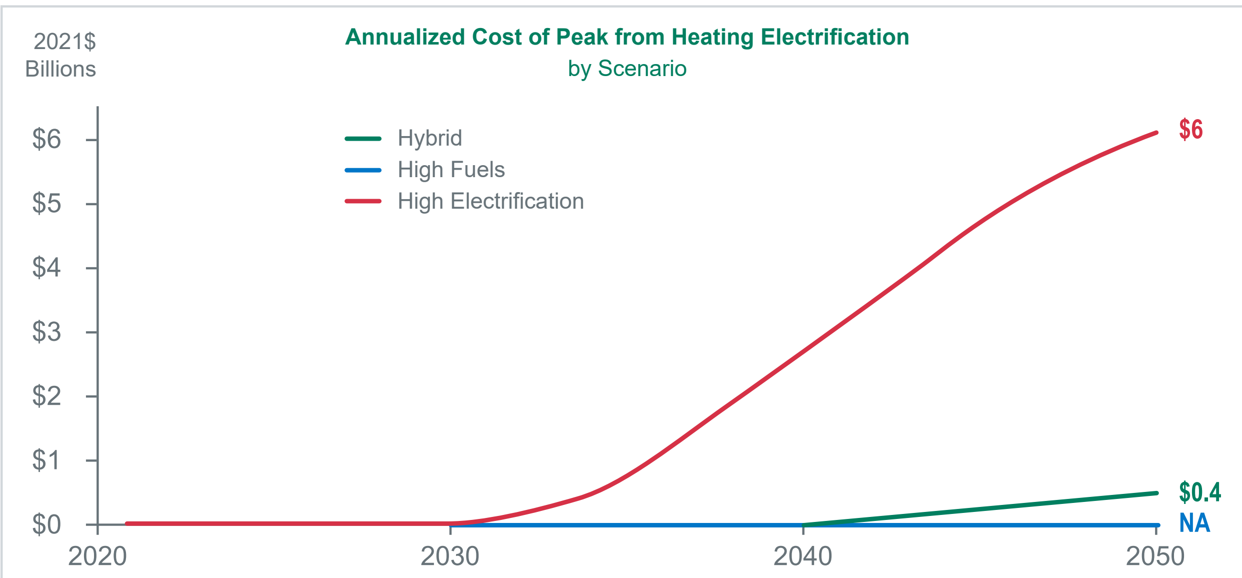
[19] Cost of reductions per metric ton of CO2e reduced = (Total Decarbonization Scenario Costs – Total Reference Scenario Costs) / Total Metric Tons of CO2e reduced. Costs of reductions per measure are similarly calculated using the incremental cost over Reference and the reductions attributable to that measure.

Adding the incremental cost of fuel with the electric system costs shifted and reduced the relative cost for each type of equipment. The greatest shift occurs in the High Electrification scenario: the relatively low cost of reduction from the equipment alone is pushed above $400 per metric ton when all costs are included. The ASHP conversion strategy in the High Electric scenario becomes the highest-cost measure of the scenario, driven by the costs to meet winter peak demand. Seeing that the Hybrid scenario's dual-fuel strategy limits the winter electric peak impact, the ASHP+NG achieves the lowest cost reductions in that scenario.

In each of the decarbonization scenarios, the cost of efficiency is the same since each scenario employs the same level of efficiency across the New England building stock, at $178 per mt$CO_2$e.

In all scenarios, industrial demand is held constant across the timeframe of the study and is deemed, for the purposes of the analysis, a "hard-to electrify" source of gas demand. All carbon reductions of industrial usage are achieved exclusively by using low carbon fuels, and thus the cost per metric ton of CO_2e reduction for the industrial sector represents the incremental costs of the fuels relative to the cost of natural gas in the Reference scenario.

Figure 9: Cost of Meet Peak Electric Capacity, 2020-2050



Required Peak Capacity and Annualized Costs (selected years)

	Capacity and Costs for Years:	2030	2035	2040	2045	2050
Hybrid						
Total Peak Demand from Electrified Heating	GW	2	5	7	10	11
New Peak T&D Capacity Required	GW	-	-	<0.1	2	4
New Peak Generation Capacity Required	GW	-	-	-	-	-
Annualized Cost of Required Capacity	2021$ Billions	**$ -**	**$ -**	**<$0.1**	**$0.2**	**$0.4**
High Electrification						
Total Peak Demand from Electrified Heating	GW	7	12	18	24	27
New Peak T&D Capacity Required	GW	0	5	11	16	20
New Peak Generation Capacity Required	GW	0	1	6	13	17
Annualized Cost of Required Capacity	2021$ Billions	**$ -**	**$0.8**	**$2.7**	**$4.7**	**$5.9**

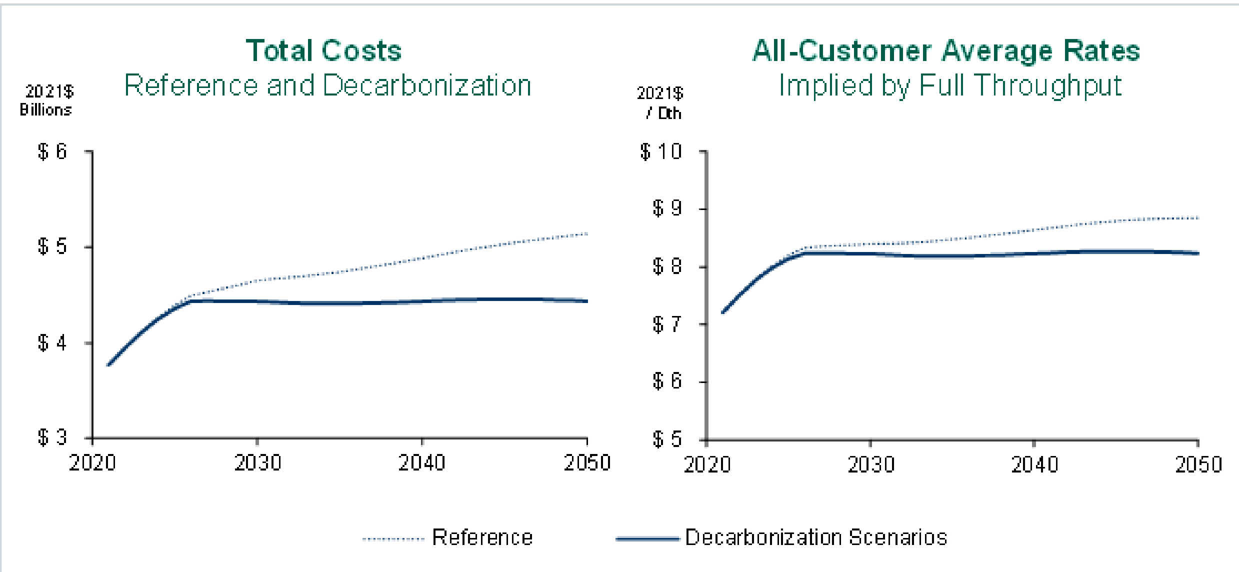
Cost to Meet Electric Peak Capacity

The cost to meet winter peak demand from electrified heating closely follows the curve of peak demand once it exceeds ISO-NE's projected summer peak (Figure 9). In the High Electrification scenario, the costs for new generation capacity and T&D upgrades begins after 2030 and is about $6 billion in annualized costs by 2050. While the dual fuel heating strategy of the Hybrid scenario limits the impact on winter peak electric demand, incremental costs for generation and T&D do not begin to accumulate until 2040 and reach a much more modest $0.4 billion by 2050. As noted earlier, the cost of peak capacity is one of the largest cost differentiators between the High Electrification scenario and the Hybrid scenario.

Cost of Service

Cost of Service in the near-term (through the mid- to late-2020s) grows rapidly, driven by current large-scale investment programs (primarily pipe replacement).[20] Over the longer term, the Cost of Service moderates to a level of investment that allows Cost of Service rates in real terms to stabilize, Figure 10. For the Reference scenario, this means that investment is aligned with the growth in customers and demand. For all

Figure 10: Cost of Service Total and Implied Rates, 2020-2050



Cost of Service Totals and Implied Rates (selected years)

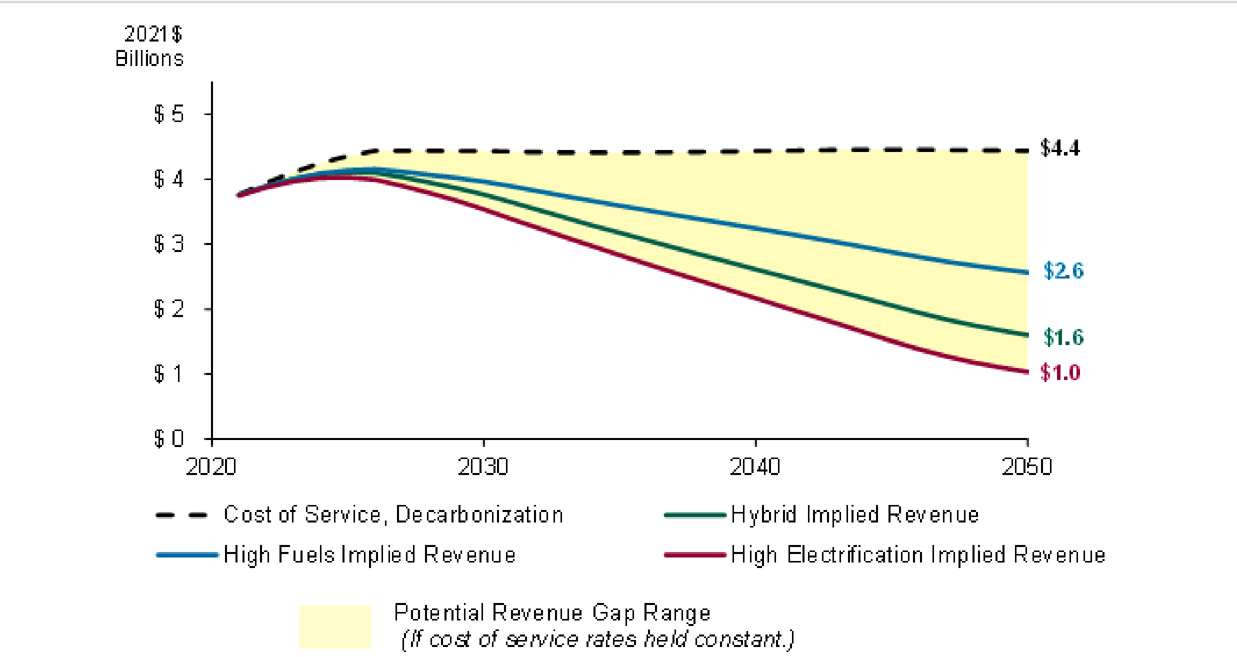
Volumes and Costs for Years:		2021	2030	2040	2050
Reference *(Long-term Customer and Volume Growth)*					
Total Cost of Service	2021$ Billions	**$3.8**	**$4.6**	**$4.9**	**$5.1**
Total Throughput	Million Dth	523	553	565	580
Implied All-Customer Average Rate	2021$ / Dth	**$7.20**	**$8.40**	**$8.60**	**$8.90**
Reference *(Long-term Customer and Volume Growth)*					
Total Cost of Service	2021$ Billions	**$3.8**	**$4.4**	**$4.4**	**$4.4**
Static Volume for Implied Rate Calculation	Million Dth	523	537	537	537
Implied All-Customer Average Rate	2021$ / Dth	**$7.20**	**$8.30**	**$8.30**	**$8.30**

[20] The Cost of Service for New England LDCs has been estimated using an aggregated regulatory financial model that projects the primary elements driving a utility Cost of Service revenue requirement (capital investment, depreciation, taxes, and operations & maintenance).

the decarbonization scenarios, total Cost of Service is held roughly constant, to approximate a condition of maintaining the system reliably but with little growth; in all of the decarbonization scenarios, total throughput of gases declines though the number of customers do increase in Hybrid and High Fuels. Holding Cost of Service at a static, maintenance level, for the decarbonization scenarios assumes that aggressive new investment in the system would be challenged by the goals of decarbonization efforts. It also assumes that the safety and the reliability of the system would need to be maintained over the entire study period and that the ability to reduce the size and cost of the system may be limited.

A path of rapid decarbonization poses several important risks to utility Cost of Service revenue and with it the ability of the region's LDCs to maintain the reliability and safety of their systems. The central risk is the cost to maintain the system as gas throughput declines. In this situation, either Cost of Service rates will need to increase rapidly or, if regulators hold rates steady, growing revenue gaps could be created between Cost of Service revenue and the total cost to maintain the gas network. Figure 11 compares the total Cost of Service projected for the decarbonization scenario to the implied Cost of Service revenue if rates were held constant in real terms. Using this lens, the High Electrification scenario creates the largest potential gap and poses the greatest risks to customers and to the LDCs. As customers and throughput decline under rapid electrification, the cost to maintain the system must be spread over fewer customers and lower demand. Affected customers are likely to be those who are unable to take advantage of energy efficiency programs or replace their heating equipment with high efficiency appliances. Since the

Figure 11: Cost of Service and Implied Rates, 2020-2050



Cost of Service and Potential Revenue Gap in 2050

2021$, Billions (except where noted)		Hybrid	High Fuel	High Electrification
Cost of Service (Decarbonization Scenarios)	2021$, Billions	**$4.4**	**$4.4**	**$4.4**
Static Volume for Implied Rate Calculation	Million Dth	537	537	537
Implied All-Customer Average Rate	2021$ / Dth	$8.30	$8.30	$8.30
Total Scenario Gas Throughput	Million Dth	194	311	125
Implied Revenue at Total Gas Throughput	2021$, Billions	**$1.6**	**$2.6**	**$1.0**
Implied Potential for Revenue Gap	2021$, Billions	**-$2.8**	**-$1.9**	**-$3.4**

High Fuels scenario uses the largest amount of gases and retains all projected customers, its potential for a revenue gap is lower than the other scenarios, but is nonetheless a significant one. Due to the complex interaction to maintain the gas system and the potential trajectory of customer rates under rapid decarbonization paths, the risks to and from the Cost of Service are among the most difficult problems to address for gas LDCs in their efforts to reduce theirs and their customers carbon emissions.

Conclusion

This report summarized three distinct decarbonization scenarios and the associated costs of decarbonizing natural gas use in the New England region by 2050. This study focused on reducing emissions associated with existing natural gas demand from the building sector. Changes to demand are projected forward with modeling of different pathway scenarios of fuel mixes and equipment deployments to test the impact of different technology options on energy consumption, emissions reductions, and system costs.

The analysis considered three decarbonization scenarios that assessed the GHG emission trajectories of the residential, commercial, and industrial sectors for natural gas demand. The High Electrification and High Fuels scenarios examine decarbonization paths that rely heavily on a single strategy: fuel switching in the case of High Electrification and low-carbon alternatives in High Fuels. **The Hybrid scenario, DSI's recommended path for the New England region, balances the two strategies.** Balancing these strategies represents an optimization of both cost and feasibility and results in a strategy that could have greater success, fewer implementation challenges, and be deployed with lower overall costs than the other two scenarios.

After assessing the peak demand from electrified heating in the two scenarios (Hybrid and High Electrification) that employ electricity-based heat pumps, peak demand steadily rises over time as the number of electricity-based heat pumps increases. In the High Electrification scenario, the peak demand for electricity is estimated to reach 27 GW by 2050. **The Hybrid scenario, however, creates less than half the peak demand by 2050 and is estimated to reach 11 GW.** Both scenarios have comparable levels of air source heat pumps, with the number of ASHPs in High Electrification only six percent larger than that in Hybrid scenario.

Although the direct effect of each scenario's costs may not fully be borne by individual rate payers, as incentives and other mechanisms could spread costs more broadly, the cost projections in this analysis are designed to represent the full economic impact of each scenario. Each of the decarbonization scenarios costs more than the Reference scenario, which has a projected cost of just over $11 billion in annualized costs. **The Hybrid scenario is projected to be the least-cost decarbonization path, incurring just under $16 billion in annualized costs in 2050, 42 percent higher than those projected for the Reference scenario in that year.** The High Fuels scenario is projected to cost just under $19 billion annually by 2050, a cost premium to the Reference scenario of 71 percent, and the High Electrification scenario is projected to cost over $20 billion in annualized costs, 84 percent greater than the Reference scenario.

Additional key findings include:

- Energy efficiency is among the most cost-effective decarbonization measures available today.
- Dual-fuel (electric and gas), or hybrid heating strategies are a key and cost-effective strategy that can achieve significant emissions reductions from current conventional natural gas consumption in New England.
- Decarbonized fuels are an effective and scalable strategy when used in buildings for meeting winter peak heating demand in cold weather climates and difficult-to-electrify uses like industrial processes.
- Decarbonizing building sector natural gas end-uses is highly dependent upon regional conditions and creates unique needs requiring New England-specific approaches to achieve reliable and cost-effective emissions reductions.