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21-05002

Public Utilities Commission of Nevada
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Conservation Advocates
550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation regarding long-term planning for natural gas utility service in Nevada.	)))	Docket No. 21-05002

COMMENTS OF NATURAL RESOURCES DEFENSE COUNCIL, WESTERN RESOURCE ADVOCATES, SIERRA CLUB, THE NEVADA CONSERVATION LEAGUE, AND THE SOUTHWEST ENERGY EFFICIENCY PROJECT[1]

1. Introduction

Western Resource Advocates ("WRA"), the Natural Resource Defense Council, Sierra Club, the Nevada Conservation League, and the Southwest Energy Efficiency Project ("SWEEP") (collectively, the "Conservation Advocates") submit these comments in response to the Procedural Order issued by the Public Utilities Commission of Nevada's ("Commission") in Docket No. 21-05002. The Commission requested interested parties submit comments responsive to the questions outlined in the Procedural Order. The Conservation Advocates respond to selected questions asked in Phase 1 of the docket, as appropriate, below.

The Conservation Advocates deeply appreciate the Commission's interest in this topic. Investigating the future of natural gas ("fossil gas") in Nevada is of utmost importance, both from ensuring that Nevada is doing its share to prevent the worst effects of climate change, but also being among the leading states in addressing this issue directly. While we acknowledge that this investigation is not intended to resolve the issues posed by the use of fossil gas in Nevada or some of its alternatives, this investigation is an incredibly important step in understanding what the options are, and what Nevada can do in the next five, ten, and twenty years to achieve its goals.

[1] Synapse Energy Economics assisted with the development of the comments.

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2. Phase 1 (ii): To achieve Nevada's goals of reducing greenhouse gas emissions, is it necessary to reduce the use of natural gas within the State? How much does natural gas use contribute to statewide greenhouse gas emissions, and what is the breakdown of emissions by type and location of natural gas use?

a. To achieve zero or near-zero greenhouse gas emissions by 2050, Nevada needs to nearly eliminate the use of fossil methane gas.

As acknowledged by the Commission in this query, Nevada's state policy is to reduce emissions of all greenhouse gasses ("emissions") to "zero or near-zero" ("zero") by 2050.[2] Similarly, the legislature set goals for reducing emissions by 28 percent by 2025, 45 percent 2030 relative to 2005 levels, and to zero or near-zero by 2050[3]. Finally, Nevada continues to advance the 2025, 2030, and 2050 legislative goals through executive action,[4] Executive Order 2019-22,[5] and additional legislation.[6] The Conservation Advocates strongly recommend the Commission consider both near-term, 2025 through 2030, and long-term, 2050, emissions reduction goals. A long-term focus is needed for Nevada to make good decisions about long-lasting infrastructure and avoid locking itself into technologies that cannot be part of a zero-emission future. Even shorter-lived, reversible investments should be scrutinized if they encourage or require additional investment in infrastructure that is incompatible with a zero-emissions future.

Nevada's 2020 State Climate Strategy states that "[i]n order to meet Nevada's long-term goal of zero or near-zero greenhouse gas…emissions by 2050, transitioning away from natural gas is necessary."[7] Residential and commercial sector use of fossil gas accounted for 8.8 percent of

[2] NRS 445B.380(2)(d).
[3] *Id.* Subs. 2(c)(1) and (2).
[4] Steve Sisolak, "Letter to Governor Cuomo, Inslee, and Newsom," March 12, 2019, https://bit.ly/3aZtA3r
[5] Accessible at https://bit.ly/3n9hx9z
[6] NRS 445B.380(2)(d); also NRS 704.7820, *et seq.*, "Senate Bill 448" (2021), [cite].
[7] "State Climate Strategy", State of Nevada Climate Initiative, (December 1, 2020), p. 165, https://bit.ly/3aV2ASJ

Nevada's gross emissions in 2016.[8] These emissions are not expected to decline without new actions, according to the Nevada Division of Environmental Protection's 2019 inventory[9]. The Reference Scenario in Evolved Energy's Nevada-specific analysis,[10] an analysis discussed in detail in Section 2-c below, shows increasing building sector emissions in the future absent new actions. If other sectors in Nevada, such as power and transportation, cut emissions, but those from fossil gas use stay the same or increase, it will be impossible for Nevada to meet 2050 goals.

b. Economy-wide modeling should be leveraged to answer questions about the future of the gas system in the state, in the context of the state's goals.

To understand the potential future role of fossil gas in the state, Nevada needs to look not at gas distribution utilities in isolation, but as part of the broader energy economy. Reaching zero emissions statewide by 2050 will require all sectors to act, but not every sector will need to reduce emissions on the same schedule: it is easier and cheaper to reduce emissions in some sectors. For example, Nevada has experienced large reductions in its electricity sector, where emissions decreased 51 percent between 2005 and 2017,[11] compared to the transportation (the next most-reducing sector) where emissions decreased by 8 percent.[12] However, other sectors' emissions have increased. Sectors like aviation or high-temperature heating in industry, may be harder and more costly to decarbonize, and thus, may decarbonize later.

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[8] "Nevada Statewide Greenhouse Gas Emissions Inventory and Projections, 1990-2039, 2019 Report", Nevada Division of Environmental Protection, (2019), Tables 2-1 and 6-1, p. 8 and 49, respectively, https://bit.ly/3pxym0X.

[9] *Id.*, Figure 6-4, p. 50.

[10] Dylan Sullivan, et al., "Pathways and Policies to Achieve Nevada's Climate Goals: An Emissions, Equity, and Economic Analysis" (Evolved Energy, GridLab, NRDC, Sierra Club, October 2020), Figure 22, p. 51, https://bit.ly/3BZbISq

[11] "Nevada Statewide Greenhouse Gas Emissions Inventory and Projections, 1990-2040, 2020 Supplemental Report" (Nevada Division of Environmental Protection, 2020), https://bit.ly/3jhRa0d

[12] *Id.*, Table 3-1, p. 25.

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550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

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The Commission should be cognizant of the linkages between sectors as it compares pathways to reaching zero emissions. Stated another way, many sectors will likely end up competing for resources to decarbonize, such as feedstocks. For example, using a large share of Nevada's available waste biomass in gas distribution to use in buildings would preclude the use of those same resources to provide high temperature heat in industry or long-duration energy storage for the electricity sector. Another consideration is the total cost of decarbonization, where some sectors will require more resources to abate emissions than others. Again, the aviation sector has a much higher "abatement" cost (i.e. the cost of reducing its reliance on fossil fuels) than gas distribution. As a result of the higher abatement cost, a large share of alternative fuels will likely be used in this sector.

Economy-wide decarbonization modeling, often referred to as "pathways" modeling after the original model[13], helps policymakers understand the tradeoffs between different emissions reductions strategies. These models start with a detailed description of how energy is used in a state or other geographic area, and how the energy-using items in the economy—cars, water heaters, commercial HVAC systems, etc.—could be changed to reduce emissions. This description incorporates the age of the energy-using item and each item's average lifetime, allowing the items to be replaced at the end of their lifetime (called "turnover"). The model also accounts for the cost of these changes. This stage of modeling depends on the inputs of the modeler: a modeler could decide to model a scenario where cars keep using liquid fuels or a scenario where methane gas or other piped fuels remain in wide use in buildings. The result of this description of energy demand—referred to as the "demand side" of the model—is a set of

[13] See "Section 2.3 The role of pathways in planning" in Jones, *et al*., "Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study," December 2020, https://bit.ly/3DXIKD2

demands for different energy sources: how much the inventory of energy using items in the geographic area demands from each fuel type each year. These fuel demands are then given to the "supply side" of the model. On the supply side, the model builds and operates the energy supply system (power plants, refineries, hydrogen electrolyzers, digesters, etc.) in order to meet each scenario's fuel demands at lowest cost, subject to constraints and the need to meet greenhouse gas reduction goals.

c. Evolved Energy Research conducted Nevada pathways modeling that shows Nevada can get to zero emissions at reasonable cost; however, to do that gas use in buildings is eliminated through electrification.

As input for Nevada's climate planning, NRDC, Sierra Club, and Gridlab commissioned Evolved Energy Research ("Evolved") to conduct pathways modeling. Evolved modeled emissions reduction pathways to meet Nevada's 2030 and 2050 goals, using the EnergyPATHWAYS and RIO models to study the energy system. Collectively, these tools model Nevada's energy supply and demand, including turnover, over time, of the stock of energy demand and supply equipment, hourly electricity dynamics, and sectoral interactions, as described in the previous section.

The modeling's key scenario, referred to in the report as the "Core" scenario, meets 2030 and 2050 goals with a rapid shift toward electric vehicles and electricity-using devices and appliances in buildings, coupled with a fast increase in the use of renewable energy sources and storage to meet existing and increased electricity demands. The key results by sector are in the graph below, included in the report as Figure ES-2.

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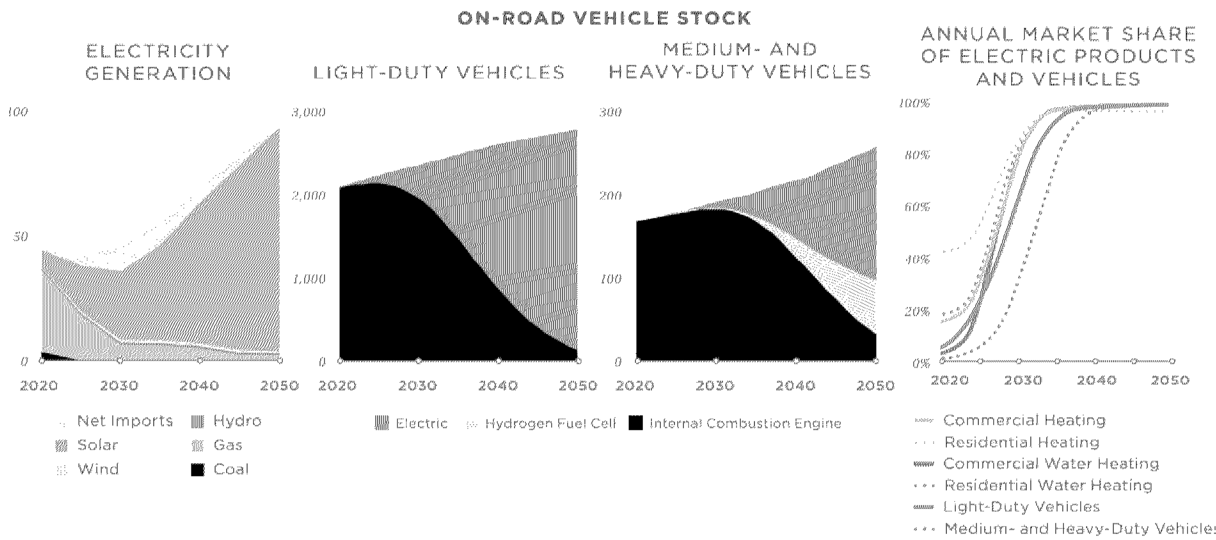
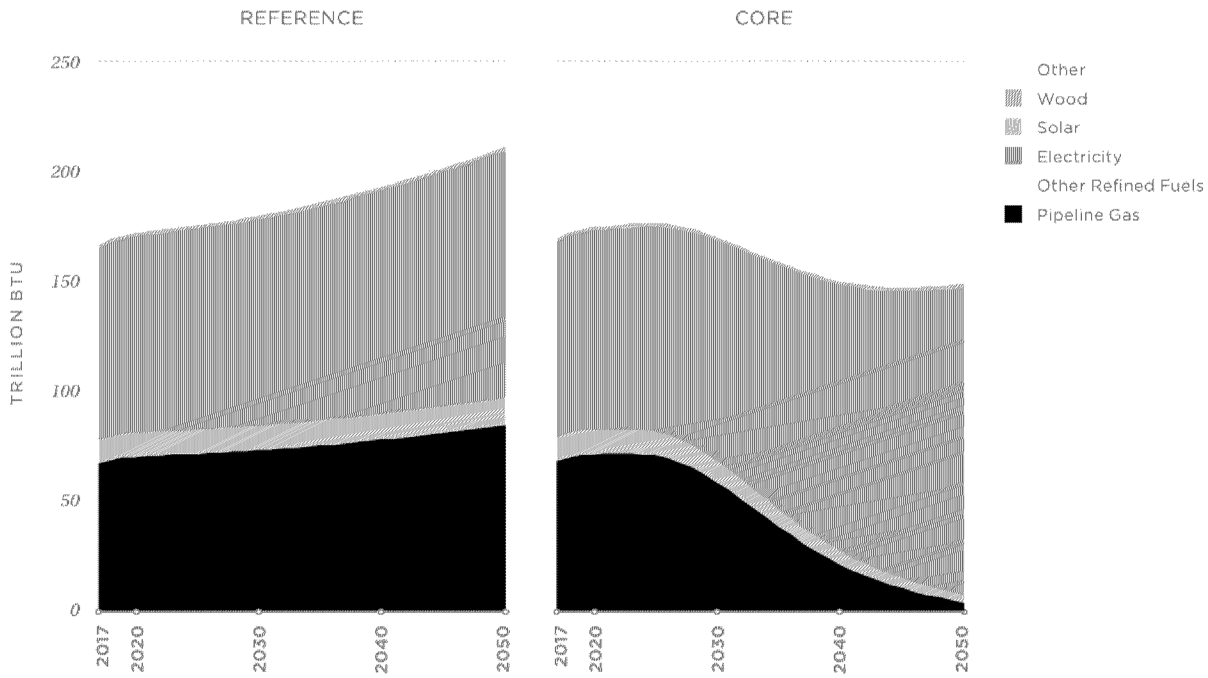
Figure 1. Pathways Key Results



In the Core scenario, gas use in buildings is nearly eliminated through the replacement of expired gas equipment with efficient electric alternatives, such as heat pumps for space and water heating, as shown in the graph below, Figure 2, that compares total building energy use, by fuel, in the Reference Scenario and Core Scenario. The base of the graph, in black, is pipeline gas, which declines to near-zero by 2050 in the Core Scenario, which reaches net-zero greenhouse gas emissions.

Figure 2. Total Building Energy Use, by Fuel, in the Reference and Core Scenarios.



This analysis shows that electrifying current uses of gas would help Nevada reach its goals, at a reasonable cost. Electrification is useful for two reasons. The first reason electrification is useful is because it shifts energy use from a fuel, fossil gas, where the "drop-in" options to switch throughput away from fossil fuels (synthetic natural gas, biomethane) are limited in availability and costly, to a different fuel, electricity, where zero-carbon options are comparatively cheap and abundant. In other words, the path to near-zero emissions in electricity includes proven, available, cheaper technology options. The second reason electrification is useful is because modern electric equipment, such as heat pumps and induction cooking, is far more efficient than gas equipment illustrated by the large decline in total energy use from the buildings sector between the Reference and Core scenarios.

But Evolved's Nevada pathways analysis has a limitation. Specifically, it did not compare the electrification pathway in the Core scenario to a pathway that seeks to retain building use of piped fuels while meeting Nevada's goals. In other words, the analysis showed that Nevada can

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meet its goals at a reasonable cost and risk with building electrification, but it did not examine whether it would be possible, at reasonable cost and risk, to meet zero emission goals while retaining use of piped fuels. However, other pathways analyses have examined how a decision to retain use of the gas distribution system to provide heat in buildings would affect a state's overall decarbonization effort.

d. Pathways Analyses for Other States

The most comprehensive pathways analysis examining the future of gas utilities in the context of long-term emissions reduction goals is entitled the "The Challenge of Retail Gas in California's Low-Carbon Future: Technology Options, Customer Costs and Public Health Benefits of Reducing Natural Gas Use,"[14] conducted by Energy and Environmental Economics, Inc., ("E3") and the Advanced Power and Energy Program at the University of California, Irvine, on behalf of the California Energy Commission, in 2020. E3's study evaluates scenarios for meeting California's climate goal of an 80 percent reduction in greenhouse gas emissions by 2050 relative to 1990 levels by focusing on the impacts of those goals on gas customers and the gas system. The study characterized, in detail, the cost and availability of fossil gas alternatives (biomethane, hydrogen and synthetic natural gas ("SNG"), which is methane produced by combining hydrogen and carbon), and concludes that "building electrification is likely to be a lower-cost, lower-risk long-term strategy compared" to relying on fossil gas alternatives.[15] Chapter 2, Technology Options to Decarbonize the Natural Gas System, and Chapter 3,

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[14] Dan Aas, *et al.*, "The Challenge of Retail Gas in California's Low-Carbon Future - Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use" (April 2020), https://bit.ly/3jkyjkS

[15] Id., Page iii.

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California Economywide Decarbonization Scenarios, especially merit the Commission's attention in this phase of the Docket.[16] Key results include:

- Decarbonization with blended and "drop-in" piped fuels results in fuel costs that are prohibitively expensive. In the scenario where 80 percent emissions reductions are achieved without building electrification, and where the gas pipe transports a mix of biomethane, green hydrogen,[17] and power-to-gas methane, the aggregate commodity costs of piped fuels increase from $0.059/therm in the reference scenario (reflecting just the EIA's forecast of 2050 fossil gas costs in the Pacific region) to $1.8/therm and $2.9/therm, depending on whether optimistic or conservative assumptions are used for the cost of power-to-gas methane.[18] These per-therm costs of piped fuels in the "retains gas" scenario assume that in 2050 56 percent of piped gas is fossil gas, which is possible because California's "80 percent by 2050" goal leaves some room for remaining emissions from fossil gas. In a scenario where gas distribution completely decarbonizes—a scenario that best represents Nevada's zero emissions goals—E3 estimates the commodity cost would be between $5.50/therm and $9.00/therm.[19]
- The supply of biomethane is limited. E3 concluded that "relatively low-cost [renewable natural gas, or "RNG"]" is sufficient to meet less than half of California's pipeline gas demand in 2050, so a "no electrification" scenario requires much more costly power-to-gas resources.[20]

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[16] The full report is attached to these comments at Attachment 1.
[17] As discussed in Section 3(b)(2) below, so-called "green" hydrogen is produced by splitting water using electrolysis, with electricity derived from non-emitting sources. In theory, this process could produce nearly zero-emission hydrogen, depending on the source of electricity used for electrolysis.
[18] *Id.*, p. 34.
[19] Ibid.
[20] *Id.*, p. 24-25.

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- The "no building electrification" scenario, which relies on fossil gas alternatives to reduce emissions, incurs higher cost and risk than the building electrification scenario. The costs to operate an electric heat pump space heater are expected to be lower than the costs of operating a gas furnace in 2050, even if the gas furnace is burning 100 percent fossil gas. In scenarios that actually reach California's goals, the difference increases.[21] The all-in, economy-wide costs of the "no building electrification" scenarios are higher, by an extra \$5 to \$15 billion in 2050.[22]

The second study of note is Evolved's work for the Washington State Energy Strategy. Evolved compared a building electrification scenario to one where gas use in buildings is retained and found that the share of state GDP spent on energy costs is lower under the electrification scenario.[23] Third is Evolved's report for the Massachusetts 2050 Decarbonization Roadmap Study.[24] The study found that a scenario that retains gas for heating buildings (the "low building electrification pathway") results in energy system costs more than \$1.5 billion per-year higher in 2050 than a scenario that relies on building electrification.[25] While a "retains gas" scenario avoids some building equipment and electricity cost, this is more than offset by increased gas commodity costs, and ripple effects on other, harder-to-decarbonize sectors.[26] The Massachusetts study summarized its conclusion on building electrification as follows:

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[21] *Id.*, p. 40.
[22] *Id.*, p. 36.
[23] See Washington State Department of Commerce, "2021 Washington State Energy Strategy: Chapter B. Achieve the State's Greenhouse Gas Emission's Limits," (2021), at p. 39, https://bit.ly/3G8NjMG; and "Appendix A, Washington State Energy Strategy Decarbonization Modeling Final Report," https://bit.ly/3vBCCgx
[24] Jones, *et al.*, "Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study," December 2020, https://bit.ly/3DXIKD2
[25] *Id.*, Figure 62, p. 121.
[26] *Id.*, Figure 7, p. 34-35.

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- "Given the assumptions of this analysis, high levels of building electrification lowered the long-term cost of reaching Net Zero. With less building electrification, the long-term cost of the decarbonized fuel required to reach the emissions target more than offset modest cost savings from avoiding electrification in the near term.
- The large quantity of decarbonized drop-in fuels required is a risk factor for a low building electrification pathway. Even with nearly complete electrification of on-road vehicles, bioenergy imports would nonetheless need to increase to five times the level of ethanol imports today.
- In a low building electrification pathway, average gas rates increased from roughly $10/MMBtu to $20- $30/MMBtu due to a combination of biogas cost, lower pipeline throughput, and the marginal carbon price of the remaining natural gas in the system. This makes gas less competitive with electricity than it is today. If adoption of electric technologies is seen by customers as cost effective based on the relative retail rates of gas and electricity, there could be an uncontrolled exit from the gas system and escalating rates for the remaining customers.
- A high building electrification pathway, whether resulting from explicit policy or market choices by consumers, will require a policy strategy for how to manage an orderly and equitable exit from the gas distribution system."[27]

The entire report is attached as well.[28]

[27] *Id.*, p. 4.
[28] Attachment 2.

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3. Phase 1 (iii). What are the options for converting the identified categories of natural gas usage to a decarbonized energy source (e.g., electrification, renewable natural gas, hydrogen, etc.)? Compare the options, accounting for the relative reduction in greenhouse gas emissions (full fuel-cycle analysis), feasibility/scalability, and functionality as an alternative to natural gas.

A. How can low-income and historically underserved communities be protected during any transition to a decarbonized energy system?

B. Please identify any equity issues that may arise under paths toward decarbonization of the natural gas system.

The following sections address the Commission's questions in subsection iii of Phase 1 by examining the different categories of alternative energy sources, the emissions impact of using those sources, and the feasibility, scalability, and functionality of different energy sources is. Following these analyses is a discussion on the equity implications of different energy sources.

a. Alternative energy options by usage category

i. Space Heating

Air conditioner and heat pump technologies have existed for many decades. Electric heat pumps are energy efficient heating and cooling systems. Heat pumps use the same vapor-compression refrigerant cycle as air conditioners do and have a function to reverse the cycle to produce heat. Heat pumps can provide space and water heating in all types of buildings and are already cost-competitive alternatives to fossil gas space and water heating systems, largely because they have a 250 percent efficiency for space and water heating. By comparison, methane gas systems typically operate at 90 percent efficiency for space heating. Furthermore, heat pumps can feasibly provide zero emission heating in a fully decarbonized grid. In recognition of heat pump's efficiency, the 2022 ENERGY STAR Most Efficient recognition criteria exclude gas-fueled equipment.[29]

[29] U.S. Environmental Protection Agency, *ENERGY STAR Most Efficient 2022 Final Criteria Memo* (September 28, 2021). Available at https://bit.ly/3G3uhHn

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However, heat pump deployment has been more limited in cold climates because the ability of early air-source heat pumps ("ASHP") that use ambient air as a heat reservoir to effectively operate as space heaters degrades as the temperature drops. Conventional heat pumps typically use inefficient electric resistance heaters as a backup in cold climates. However, cold climate ASHPs have become widely available across the country over the past several years. Cold climate ASHPs can provide comfortable heat even under freezing temperatures (e.g., down to -20°F) without a backup heater, meaning that they can meet heating needs even in Nevada's coldest cities such as Elko and Reno. A field study in Vermont observed that cold climate ASHPs operated at 5°F with a Coefficient of Performance ("COP")[30] of 1.6 and even at -20°F at above 1 COP.[31]

Since cold climate ASHPs have become available, some northern states have been aggressively promoting and installing heat pumps. For example, Efficiency Maine, tasked with meeting Maine's goal of 100,000 heat pump installations, has installed over 82,000 high-performance ASHPs over the past nine years, with the highest single year installation of 27,326 in FY2020 (July 2020–June 2021).[32] Efficiency Maine's efforts represents a cumulative installation of nearly 15 percent of homes and a single year installation of nearly 5 percent of homes in FY2020, assuming that all installations are in residential buildings.[33] Efficiency

[30] COP indicates the ratio of useful heating or cooling to the total energy input. For example, a COP of 3 means that heat output is 300 percent of the energy input.

[31] Cadmus Group. 2017. *Evaluation of Cold Climate Heat Pumps in Vermont*. Prepared for the Vermont Public Service Department. Page 24. Available at: https://bit.ly/2Z2XzoC

[32] Efficiency Maine. 2020. *FY2020 Annual Report*. Available at: https://bit.ly/3DUpczg; State of Maine Office of Governor Janet T. Mills, "For Climate Week, Governor Mills Celebrates Maine's Progress Toward Installing 100,000 Heat Pumps by 2025." (2021) Available at: https://bit.ly/3AZLQEF

[33] Maine has approximately 560,000 households, according to U.S. Census Bureau *QuickFacts: Maine*. Available at: https://bit.ly/2Z5CYk1

Maine's energy efficiency program administrator reported reliable heating operations below -15°F.[34]

Other types of heat pumps such as ground-source heat pumps and water-source heat pumps have higher performance than ASHPs because they can use heat reservoirs with a higher temperature than ambient air during the winter. However, they are more expensive to install than ASHPs and are thus generally limited to larger scale installations.

A 2018 study by the Southwest Energy Efficiency Project ("SWEEP") found that heat pumps are substantially cheaper to install for new construction homes and also cheaper on a lifecycle basis including operating costs in Reno and Las Vegas.[35] Notably, SWEEP's study does not include the avoided cost of the new gas connection service for new all-electric homes, which would substantially improve heat pump economics as the cost of a new gas service connection is typically very expensive.[36] The SWEEP study also found that heat pumps reduce emissions by 36 to 42 percent for new construction and 14 to 22 percent for existing buildings, based on projected emissions factors through 2036. For existing homes, the SWEEP study found that heat pumps are slightly more expensive than fossil gas heating on a lifecycle basis. This means that heat pumps are likely to be the least-cost options even in retrofits in the near future as the cost of heat pumps decline due to economies of scale and as fossil gas prices increase due to customer defection and federal carbon policies that impose costs on fossil gas.

A more recent analysis submitted to the Commission by Jim Grevatt of Energy Futures Group examined the cost-effectiveness of electrification in the northern and southern territories of the

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[34] Efficiency Maine, "Heat Pumps," (accessed October 15, 2021), available at https://bit.ly/3lZ7m8h

[35] Kolwey, N., Geller, H., *Benefits of Heat Pumps for Homes in the Southwest* (2018). Table 5a on p. 17 and Appendix A at p. 33, available at: https://bit.ly/3jlIXb3

[36] For example, a 2016 study by TRC estimated about $6,400 for installing a gas service connection for a single-family home. See TRC, *Palo Alto Electrification Final Report* (2016), available at: https://bit.ly/3vwQeK5.

Southwest Gas Company.[37] The analysis included three scenarios: the current standard rate, the current time-of-use rate, and the current standard rate with a $100/ton carbon price. Mr. Grevatt found that all of the electrification options—central heat pumps for heating and cooling, heat pump water heaters ("HPWH"), and all-electric new homes—are cost-effective relative to fossil gas options in all scenarios in the northern service territory.[38] On the other hand, the analysis found that the electrification options are not cost-effective using the standard rates within the southern service territory, partly because of lower gas rates there. The analysis also found electrification of space heating and all-electric new homes can be cost-effective in the southern territory under the current time-of-use rate without carbon pricing as well as at the current rate with $100/ton carbon pricing.[39] While the HPWH was not cost-effective under the $100/ton carbon scenario, a doubling of the carbon price to $200/ton[40] would result in this option becoming cost-effective.

Other alternatives to fossil-based space heating include biomethane/RNG and hydrogen. Processed biomethane and SNG can be delivered interchangeably with fossil gas in existing infrastructure.[41] Important considerations for these fuels are discussed in the sections on GHG emissions and feasibility below. Hydrogen cannot be interchanged with methane, and consumers

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[37] Application of Southwest Gas Corporation for approval of its Conservation and Energy Efficiency Plan for the period 2022-2024, Commission Docket No. 21-05001, Direct Testimony of Jim Grevatt, submitted July 29, 2021.

[38] *Id*. Table 5, p. 22.

[39] *Id*. At Table 6. p. 23.

[40] Note that $200/ton is still below many estimates of the social cost of carbon. A recent Synapse Energy Economics study recommends the use of $393 per short ton for Massachusetts, which was based on the Federal Interagency Working Group's most recent recommendation on the social cost of carbon and a 1 percent discount rate instead of 3 percent discount rate. See Synapse, "AESC 2021 Supplemental Study Update to Social Cost of Carbon Recommendation," (2021), available at https://bit.ly/3jmzRuH

[41] In these comments, biomethane and SNG are distinguished from RNG wherever possible as the scalability and carbon implications of these fuels are different. Biomethane is produced by the digestion or gasification of biological matter. SNG is produced by combining non-fossil carbon atoms with green hydrogen.

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550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

will require different equipment to burn it safely beyond relatively low hydrogen blends.[42] Hydrogen's higher burning temperature is also prone to creating more nitrogen oxide ("NOx") pollution, potentially worsening air quality inside and outside of buildings unless additional measures are taken to control emissions, e.g. using low NOx burners.[43]

ii. Water Heating

Residential and small commercial scale HPWHs are now widely available across the country. The most popular model is a hybrid HPWH which includes an air-to-water heat pump, back-up electric resistance coils, and a hot water storage tank. While typical storage gas water heaters have 0.65 to 0.7 Uniform Energy Factors ("UEF") (which translates to between 65 and 70 percent energy efficient), HPWHs typically have a UEF above 3, making them far more efficient than gas water heaters. Best-in-the-market HPWHs are rated with upwards of 4.0 UEF, with most manufacturers currently producing models rated at 3.5 UEF. Current federal appliance standard on storage water heaters sets the minimum efficiency levels so high for a storage volume greater than 55 gallons that the only available ENERGY STAR storage water heater at this storage capacity level are HPWHs.[44]

While HPWHs are becoming mainstream water heaters, one major remaining barrier is the potential cost to upgrade the electrical panel. HPWHs typically require a 240-volt outlet, which may require a panel upgrade for old homes. To address this issue, some manufacturers including

[42] For a technical discussion of the issues discussed here, see Livermore, S., "Exploring the potential for domestic hydrogen appliances," The Engineer (2018), available at https://bit.ly/3C2vigD

[43] Frazer-Nash Consultancy, "Appraisal of Domestic Hydrogen Appliances", (2018), available at https://bit.ly/3B2ULFn

[44] Appliance Standards Awareness Project, "Water Heaters," (accessed October 17, 2021), available at: https://bit.ly/3G3jbSN.

Conservation Advocates
550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

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550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

AO Smith, Rheem, and GE, are now testing retrofit-ready HPWH models that require only 120 volt and 15 amp, which is a standard outlet rating in homes.[45]

Large-scale HPWHs are also available for commercial and industrial applications including large multifamily buildings. Such applications have been limited in the country relative to the residential applications due, in part, to the limited knowledge of large-scale HPWHs among building owners, architects, and HVAC engineers. In response, recent studies have investigated large-scale HPWHs in order to increase the awareness of these technologies.[46] Further, a growing number of new products are coming onto the market. For example, a U.S.-based HVAC manufacturer called Lync recently introduced the new large-scale HPWH "Aegis A" into the market that uses CO2[47] as a refrigerant and can heat up water to 185°F.[48]

HPWHs for commercial applications can have some advantages over residential applications because some commercial buildings have unique heat reservoirs such as waste heat or locations with warm temperatures. For example, some commercial buildings have a below-grade garage; HPWHs can be configured to use these milder temperatures in the garage as a heat reservoir to produce hot water.[49] HPWHs can also be placed where they can use waste heat from mechanical rooms or laundry rooms and also provide the added benefit of cooling and dehumidification in those rooms. HPWHs can also extract waste heat produced in certain commercial facilities such

[45] Building Decarbonization Coalition and New Buildings Institute, "The Retrofit-ready Heat Pump Water Heater: 120 Volts to the Future," (2021) available at: https://bit.ly/2Z8mqb8.

[46] Armstrong, S., et al., A Zero Emissions All-Electric Multifamily Construction Guide. Redwood Energy, (2019) Available at: https://bit.ly/3aWMckQ; Peter, A., et al, *Toward Carbon-Free Hot Water and Industrial Heat with Efficient and Flexible Heat Pumps* (2021), available at: https://bit.ly/3DYTQaL

[47] CO2 has a global warming potential of 1, by definition. Many refrigerants commonly used in air conditioning, heat pumps, and other applications have higher global warming potentials than CO2. For example, R-22 has a 100-year global warming potential of 1,810—almost 2,000 times the potency of CO2. See California Air Resources Board, "What is Global Warming Potential?" (accessed October 20, 2021), https://bit.ly/3E1E9zw

[48] Lync. "Lync Introduces Aegis, the First Commercial CO2 Heat Pump Water Heaters in North America," (accessed October 18, 2021), available at https://bit.ly/30MAGXp

[49] Ecotope, *RCC Pilot Project: Multifamily Heat Pump Water Heaters in Below Grade Parking Garages in the Pacific Northwest* (2015), available at https://bit.ly/2ZhUilE

as spas, restaurant kitchens, or wastewater treatment facilities. Finally, large buildings that have standard chiller systems with cooling towers could be good candidates for installing HPWHs, specifically heat recovery chillers. For example, Stanford University recently made a major renovation to its campus district energy system and replaced its aging methane gas combined heat and power and district steam system with heat recovery chillers that provide both chilled and heated water.[50]

Similar to space heating, biomethane, SNG, and hydrogen provide alternatives to fossil gas water heating. As mentioned above, while biomethane and SNG can be used in place of fossil gas, hydrogen requires different end-use equipment and poses other safety challenges. Our comments discuss technical limitations and environmental issues of these alternatives later in this document.

iii. Electric power generation

The options for converting a fossil gas power plant to a decarbonized energy source include replacing the power generated by the plant with non-GHG-emitting sources such as energy efficiency, demand flexibility, geothermal, wind power, solar photovoltaic, and energy storage, or changing the fuel input to the plant to a decarbonized gaseous or liquid fuel.

The Commission is very familiar with the subject of portfolio development using solar PV, wind power, energy storage, and demand-side resources in the electric sector; many electric sector planning models exist that can easily capture these options. Rocky Mountain Institute's ("RMI") analyses of "clean energy portfolios" examined the specific question of replacing the

[50] Meier, A., et al., *University of California Strategies for Decarbonization: Replacing Natural Gas*, (2018) p. 76. Available at https://bit.ly/3G8QtzO

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services provided by fossil gas power plants with non-emitting sources.[51] These reports present a methodology for developing portfolios of clean energy resources that can replicate the services provided by both combustion turbine (e.g. peaking) resources and flexible high capacity factor (e.g. combined cycle) resources.

With adequate safeguards to ensure low- or zero-GHG emissions, biomethane, SNG, or other kinds of low- or zero-GHG methane sources are drop-in options that can be used without making changes in the power plant itself. When considering non-fossil methane sources, energy planners consider the cost and availability of the fuel, its alternative uses, and competition in procuring the fuel. Biomethane also presents a different option for electricity generation; specifically, combustion at the site of creation before scrubbing the gas to pipeline quality. This option avoids the cost of scrubbing equipment and pipeline extensions, which may not outweigh the loss of flexibility due to a lack of on-site gas storage, loss of economies of scale, and increased maintenance costs due to contaminants in the gas stream. Local air quality should also be considered in weighing the best use of biomethane.

A low level of hydrogen blending (e.g., 20 percent) is possible, depending on the specifications of the plant; although as discussed below, this limits GHG reduction to just a few percent on an energy basis. Pure hydrogen, on the other hand, cannot be used in existing combustion turbines because hydrogen's combustion properties would result in unacceptably large NOx emissions. Specifically, hydrogen burns hotter than methane, which results in the creation of additional NOx. While turbine manufacturers are working to address this issue and market hydrogen-ready turbines, the technology is not mature, and some level of capital

[51] RMI, *The Economics of Clean Energy Portfolios*, (2018) available at https://bit.ly/3G6yn1t; RMI, *The Growing Market for Clean Energy Portfolios*, (2019) available at https://bit.ly/3vwTzZR; and RMI, *Prospects for Gas Pipelines in the Era of Clean Energy*, (2019) available at https://bit.ly/3pgCdPI

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investment up to and including turbine replacement would be required to use hydrogen for this purpose. Fuel cells can also be used with hydrogen fuel to replicate the services of combined-cycle gas plants. In any event, using pure hydrogen requires a separate pipeline and storage infrastructure. Moreover, as discussed below, the GHG emissions of hydrogen varies greatly depending on how it is produced.

iv. Industrial processes and feedstocks

The potential ability of hydrogen to decarbonize industrial processes is difficult to quantify or qualify because of the diversity of end uses in the industrial sector and the particularities that matter for any given facility and market. Low- or zero-GHG methane, such as some types of biomethane or SNG, could be used to reduce or eliminate emissions without changing processes. In all cases, fuel costs and competitive pressures will shape the space of practical solutions.

The "hydrogen ladder" presented in Figure 3 provides a useful framework for considering different end uses. In this ladder, end uses are graded from A to G based on how likely it is that hydrogen will play a substantial role in the future decarbonized version of each market. The ladder reflects both technological and economic feasibility. Figure 3 indicates that biomethane and electricity are competitors to hydrogen, highlighting that there may be higher and better uses for biomethane and green hydrogen than as a drop-in or blended fuel in gas distribution systems.

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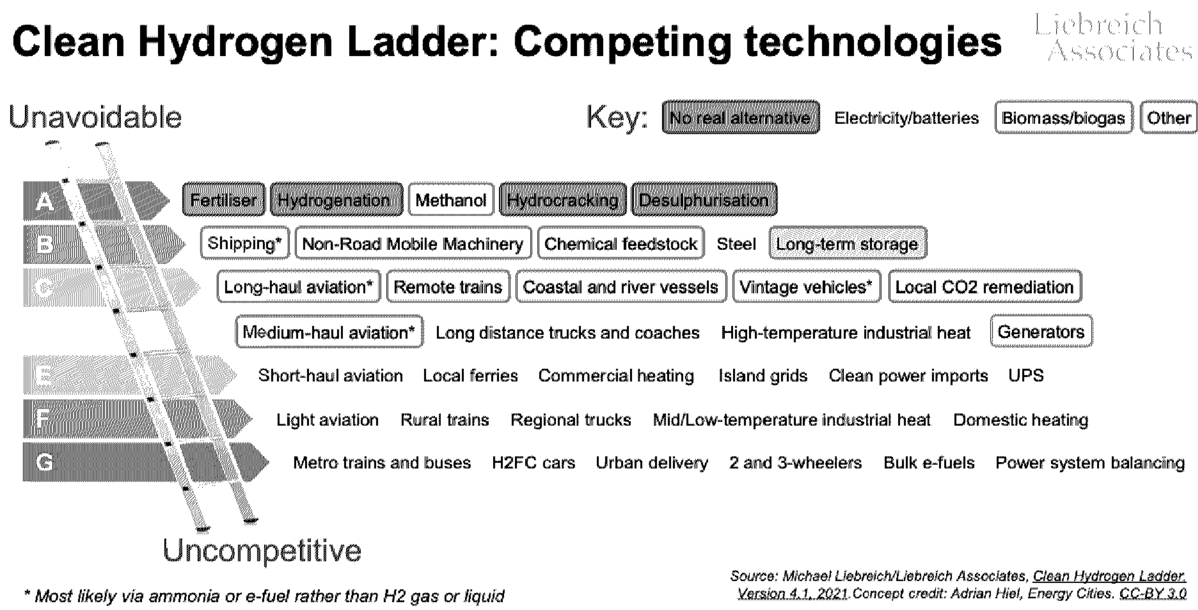
Figure 3. Clean hydrogen ladder with competing technologies.[52]



As shown in Figure 3, hydrogen and biomethane are competitive in industrial applications when they are used as a feedstock. Electricity cannot be a feedstock to produce chemicals, plastics, etc. It is important to note, however, that the portion of methane gas in Nevada used for the purposes on the top four rows of this figure—where the leading clean competition is not electricity—is likely very small. We welcome further insights and data from Nevada's gas utilities and manufacturing stakeholders regarding the end uses for fossil gas in the state's industrial sector.

v. Cooking

Currently electric cooking is the best available alternative to methane gas cooking. While there are still many people who enjoy cooking with a gas stovetop, induction cookers are gaining in popularity. For other cooking devices, such as ovens, consumers are generally indifferent.

[52] Liebreich, Michael "Clean Hydrogen Ladder, Version 4.1 (2021). Concept credit to Adrian Hiel, Energy Cities CC-BY 3.0.

Since electric ovens are widely available, consumers can readily transition from a gas oven to an electric one. Finally, almost every other cooking appliance (such as microwaves, slow cookers, pressure cookers, and air fryers) is electric.

Induction cookers are high-performance technologies that have many advantages over gas cooktops. Induction cooking uses magnetic fields to excite electric currents to heat pots and pans. This method is more energy efficient than conventional gas cooking technologies because pans and pots are directly heated without any heat lost into the ambient air. Induction cooktops can transfer up to 90 percent of the energy input to the food compared to only about 40 percent with gas cooktops.[53] Practically, this means that they can also boil water faster than a comparable gas stove. Induction cooktops also have superior temperature controls that allow heat levels to be changed as fast or faster than gas. Induction cooktops are also safe to use because they only heat up pans and pots and keep the cooktop cool, making activities like cleanup easier and safer. Further, induction cooktops do not combust any fuels and thus improve indoor air quality.[54]

Barriers to increased adoption of induction cooking include: relatively higher upfront prices for low-end models, some types of cookware are incompatible, customer unfamiliarity, and customer attachment to gas cooktops. Further, installing new electric cooktops and ovens could require an upgrade to the existing electric panel in old homes, a barrier that likely calls for a policy response.

Other alternatives to fossil gas for cooking are biomethane, SNG, and hydrogen. While biomethane and SNG can be used in place of fossil gas, hydrogen cannot. Hydrogen requires different end-use equipment to burn safely. Further, hydrogen combustion may result in more

[53] Sweeney, M., *et al.*, "Induction Cooking Technology Design and Assessment," (2014), available at: https://bit.ly/3plX7Nf

[54] Silicon Valley Clean Energy, *The Basics Induction Cooktops*, (Accessed October 19, 2021), available at: https://bit.ly/2Z7opfa

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NOx pollution, thus exacerbating air quality issues inside and outside of the home. Pure hydrogen burns with an almost transparent flame, so providers would need to add colorants and odorants to provide the expected safety and aesthetic experience when cooking.

vi. Drying

Electric clothes dryers already have a large market share. According to the U.S. Energy Information Administration, the share of electric dryers is already over 80 percent among residential customers in the Mountain region, which includes Nevada.[55] Switching to electric dryers from gas dryers does not pose any significant barrier except a potential upgrade to the electric panel in some homes.

More efficient heat pump dryers are also now available in the market. Electricity requirements for heat pump dryers can be just one-third of conventional electric dryers. Thus, an upgrade to a homes' electric panel is not likely to be needed. While heating the dryer drum, heat pump dryers condense the water removed from the clothes, eliminating the need for a vent, simplifying installation and reducing air leaks from the building envelope, making them suitable for high-performance buildings. Drying time can be longer with heat pump dryers and they are substantially more expensive than conventional dryers.

The adoption of commercial electric dryers faces higher barriers compared to the adoption of residential dryers when they are switching from gas models. An electrical panel upgrade may be required, which will discourage adoption of this technology. While the electricity capacity for heat pump dryers is much lower than conventional electric dryers, the costs of heat pumps as well as longer drying time will be major barriers to the adoption of the technology for commercial

[55] U.S. Energy Information Administration, *Residential Energy Consumption Survey (RECS),* (2015) Table HC3.8 Appliances in homes in the South and West regions, 2105, available at: https://bit.ly/3prmEF3

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laundry businesses. Existing gas dryers can run on fossil gas, biomethane, or SNG. We are not aware of appliances that can use hydrogen for drying.

vii. Transportation

In Nevada, the Regional Transportation of Southern Nevada ("RTC") started converting its bus fleet to compressed natural gas ("CNG") buses in 2007. As of 2020, about 78 percent of RTC's buses run on CNG. RTC is planning to convert nearly all of its buses to CNG fuel by 2023.[56] In addition, the company Waste Management has been using CNG trucks for the past several years in some cities in the state.[57] Nevada currently has two public and four private CNG fuel stations.[58]

Electric vehicles ("EVs") are currently the least-cost and most environmentally friendly alternative to CNG vehicles. Electric buses and trucks have been increasing their market share over the past few years[59] and are already cost-competitive options to CNG vehicles. EVs have a number of advantages in terms of efficiency and emissions over CNG vehicles.

First, EVs produce no local air pollution and improve air quality in neighborhoods. This is an important benefit for replacing CNG buses and Waste Management trucks because these vehicles make numerous stops in communities that may already be heavily burdened with transportation air emissions. While CNG is generally thought to be cleaner than diesel, it still

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[56] Haas, G."RTC using $3.8M federal grant for 2 hydrogen-powered buses," (2020), available at: https://bit.ly/3DYULbd

[57] Reno Waste Management, *Waste Management Trash and Recycling Services Brochure,* (accessed October 18, 2021), available at: https://bit.ly/3aTnt0G; 2News, "Waste Management Expands CNG Fleet," (2015), available at: https://bit.ly/3Gg76tI

[58] U.S. Department of Energy, "Nevada Transportation Data for Alternative Fuels and Vehicles," (accessed October 18, 2021), available at: https://bit.ly/3vwSUqY

[59] International Council on Clean Transportation, *Race to Zero – How manufactures are positioned for zero emission commercial trucks and buses in north America,* (2020), available at: https://bit.ly/3C0WlZH

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produces pollution. In fact, some studies show that CNG vehicles produce higher levels of certain pollutants, such as particulate matter.[60]

Second, the fuel economy of EVs is generally much better than that of CNG vehicles. This advantage of EVs is particularly pronounced for EV buses and waste trucks, because the efficiency of EV buses is not substantially affected by driving at low speeds or by making stops. In contrast, vehicles with internal combustion engines are much less efficient at low speeds and when making many stops, as is required of buses and waste trucks. A recent study by National Renewable Energy Laboratory ("NREL") estimated that CNG buses had an average fuel economy of about 4.34 miles per diesel gallon equivalent ("mpdge"). In contrast, the study found EV buses had an average fuel economy of 17.35 mpdge, or over 400 percent better fuel economy.[61]

Further, EVs are already cost-competitive with CNG or diesel vehicles over their lifetimes. While electric buses and trucks are more expensive to purchase than CNG or diesel vehicles, they have substantially lower costs for maintenance and fuels. A 2021 study by Sierra Club, TransitMatters, and the Institute for Transit & Development Policy examined various bus vehicle options including electric and CNG buses for the Massachusetts Bay Transportation Authority ("MBTA").[62] Using Argonne National Laboratory's AFLEET modeling tool, this study found that (a) the purchase price of an electric bus is nearly twice that of a CNG bus but (b) the lifetime fuel and maintenance costs for an electric bus are only about 35 percent of the costs for a CNG bus, resulting in a slightly lower total cost of ownership ("TCO") for an electric bus as compared

[60] Durbin, D.T., *et al*., Evaluation of the Performance and Air Pollutant Emissions of Vehicles Operating on Various Natural Gas Blends – Phase 2 (2015), available at: https://bit.ly/3vtuQWe

[61] Eudy, L. and Jeffers, M., *Foothill Transit Battery Electric Bus Demonstration Results: Second Report*, (2017), available at: https://bit.ly/2ZclORu

[62] Sierra Club, TransitMatters, and ITDP, *BUS ELECTRIFICATION - Accelerating the Electrification of Bus Service in the Boston Metro Area*, (2021) Available at: https://bit.ly/3aXYJ7r

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to the TCO for a CNG bus. A 2021 study by NREL also estimated the TCO for Class 4 parcel delivery trucks and Class 8 tractors.[63] This study finds that the TCO is currently slightly higher for EV Class 4 trucks and Class 8 short-haul tractors than for comparable CNG vehicles, but it projects that these types of EVs will have a lower TCO than CNG vehicles in the near future when dwell time[64] is not required, which is a reasonable assumption for buses and waste trucks.[65]

Another alternative is fuel cell vehicles. The RTC of Southern Nevada was awarded a $3.8 million federal grant in 2020 to purchase two hydrogen-powered fuel cell buses and to install hydrogen-fueling infrastructure.[66] However, the availability of fuel cell vehicles is very limited. A 2020 report by the International Council on Clean Transportation ("ICCT") indicates that there is currently only one hydrogen fuel cell bus manufactured in North America and no models for waste trucks.[67] Further, the high costs of fuel cell vehicles and a lack of hydrogen infrastructure have limited the deployment of fuel cell vehicles to a few select markets, primarily in California.[68] These issues will remain major barriers to fuel cell vehicles in the foreseeable future.

Biomethane and SNG are other potential alternative fuels to fossil gas for CNG vehicles. RNG is already used for buses and waste trucks in some states like California. The federal government's Renewable Fuel Standard Program has been a main driver for promoting the use of RNG in the transportation sector over the past several years.[69] Our comments below describe

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[63] Hunter, C., et al., Spatial and Temporal Analysis of the Total Cost of Ownership for Class 8 Tractors and Class 4 Parcel Delivery Trucks, (2021), available at: https://bit.ly/3lZ6ccL

[64] Dwell time in this context is time for refueling/recharging EV batteries.

[65] According to NREL's 2021 study, Class 8 long-haul tractors (500-mile range) (not relevant to buses and waste trucks) do not have a cost advantage to other vehicle types but are expected to be cost-competitive with CNG trucks in the near future.

[66] FuelCellsWorks, "RTC Awarded $3.8 Million Federal Grant To Purchase Hydrogen Fuel Cell Buses," (2020) Available at: https://bit.ly/3AVdRwV

[67] International Council on Clean Transportation, Race to Zero – How manufactures are positioned for zero emission commercial trucks and buses in north America, (2020) available at: https://bit.ly/3aSypMa

[68] *Ibid.*

[69] U.S. EPA. "Overview for Renewable Fuel Standard," (accessed October 18, 2021), available at: https://bit.ly/3aYdkjg

supply and cost issues with RNG. Further, as discussed earlier, vehicles running on either biomethane or SNG will likely not alleviate local air quality problems.

b. Emissions Impacts

i. Electrification

Electrification will have a greater impact on emissions reductions as more renewables are added to the grid. Because Nevada's RPS of 50% by 2030[70] sets the percentage of electricity sold each year that must come from renewable energy, additional sales will require a proportionate amount of renewable energy each year. NRS 704.7820(2) also sets a goal for "an amount of energy production from zero carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State." Similarly, in order to meet Nevada's goals for reducing emissions to zero or near-zero by 2050, additional load must be met without increasing emissions. A federal carbon policy could make electrification still more impactful, reducing emissions even further than from state policy alone.

ii. Hydrogen

Hydrogen is being explored as a way to transport and store low- or zero-carbon energy. However, the GHG emissions stemming from hydrogen varies dramatically depending upon how it is produced. Hydrogen can be characterized as gray, blue, or green. Gray hydrogen is produced using steam-methane reforming ("SMR") of fossil gas, which results in emissions of CO2 as the hydrogen atoms are released from the methane molecules.[71] Almost all hydrogen produced in the United States today is gray. Assuming a methane leakage rate of 3.5 percent, gray hydrogen emits 153 grams CO2 equivalent ("CO2e") per megajoule, equivalent to 161

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[70] NRS 704.7820(1).

[71] Hydrogen can also be produced using coal gasification (brown hydrogen), but this method is much less commonly used than SMR in North America. (*See* Howarth, R., Jacobson, M., "How green is blue hydrogen?" *Energy Science & Engineering:* (2021), available at https://bit.ly/3niOAIb)

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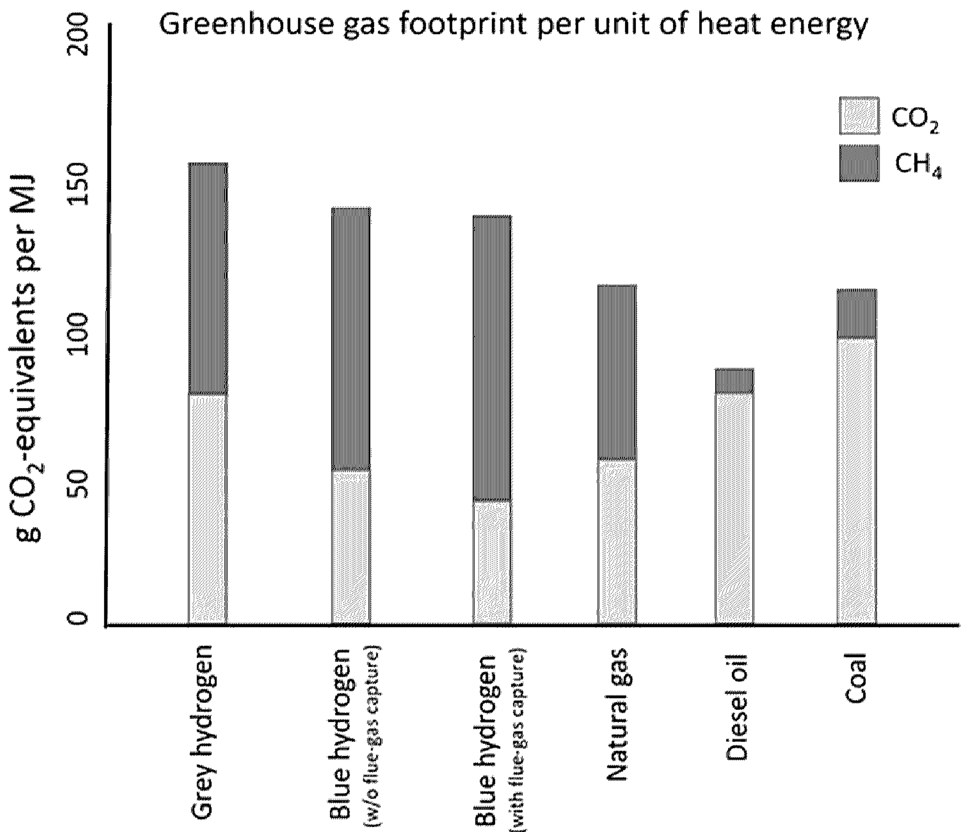
grams CO2e per MMBtu. In contrast, when burning fossil gas for heat, emission are actually lower on a GWP-20 basis, as depicted in Figure 4.

Figure 4. Comparison of CO2e emissions (on a GWP-20 basis) for grey and blue hydrogen relative to direct combustion of fossil gas, diesel, and coal[72]



One option for potentially reducing the carbon footprint of gray hydrogen is to capture and sequester the CO2 emitted in the traditional process to produce "blue" hydrogen. This can reduce GHG emissions relative to fossil methane to the extent that the CO2 is captured and sequestered and the process lifecycle does not increase leakage of methane. Because blue hydrogen uses fossil gas as a feedstock, there are emissions associated with its extraction, processing and use in the

[72] Note that CO2 from developing, processing, and transporting fuels is shown in yellow. CO equivalent emissions of fugitive, unburned methane is shown in red. Source: Howarth, *supra*.

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SMR process.[73] How "low-carbon" blue hydrogen is also depends on the efficiency of the carbon capture and how permanently the carbon is sequestered. Very careful GHG accounting is necessary to ensure "blue" hydrogen is actually a low-emission fuel.[74] Estimated emissions for blue hydrogen range from 135 to 139 g CO2e per megajoule or 142 to 146 g CO2e per MMBtu, on a GWP-20 basis, depending on whether flue gas is captured.[75]

The other primary method discussed in the literature for hydrogen production is to split water using electrolysis, with electricity derived from non-emitting sources. This produces so-called "green" hydrogen. In theory, this process could produce nearly zero-emission hydrogen. The primary challenge with green hydrogen is its cost, discussed below. The electricity source for the hydrogen production must be from renewable energy for it to be "green". Robust frameworks for tracking the input electricity in a "green" hydrogen process do not yet exist in the U.S.

iii. Renewable Natural Gas

Renewable natural gas, abbreviated RNG, is produced using one of two general pathways. The first involves the anaerobic decomposition of organic matter and the collection of the resulting biogas, or the gasification of biomass; followed by the upgrading of the biogas to pipeline quality. This pipeline quality gas is termed "biomethane." The second pathway, synthetic natural gas, abbreviated SNG, is produced by combining non-fossil carbon atoms with green hydrogen. Synthetic natural gas could be produced from fossil carbon and other varieties of hydrogen, but in the context of zero emissions goals, we assume proponents are referring to "green" SNG). Our comments address the Commission's questions regarding each of these pathways separately.

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[73] *Id.*
[74] *Id.*
[75] *Id.*

iv. Biomethane

Climate impacts associated with biomethane depend on a number of factors, including its source, how it is produced (i.e., the amount of process leakage), what would have otherwise have happened to the methane (i.e., flared off), and what energy-using technology and energy the customer would have used had the biomethane not been available. As Dr. Emily Grubert testified to before the Commission, only a small amount of RNG is likely to be carbon neutral and under some conditions observed at existing plants, RNG's GHG intensity can be greater than that of fossil gas. [76] How much GHG emissions are reduced, if they are reduced at all, depends largely on baseline assumptions and methane leakage rates at different life cycle stages. Further, the leakage rate can vary greatly, especially if there are accidental releases. Biomethane will have distribution system and end-use leakage and could still cause gas-related fires and explosions in buildings, similar to fossil gas. However, as will be noted later in our comments, RNG supply is limited and is substantially more expensive than fossil gas.

v. Synthetic Natural Gas

SNG can be created using hydrogen obtained from an electrolysis process and combined with CO2 that is captured from the air or that would otherwise be emitted. The source of energy for processing SNG, including electrolysis and carbon capture, has a substantial impact on whether and the extent to which GHGs are reduced relative to direct use of fossil gas.[77] A stream of CO2 is also needed for methanization. Leakage of the newly produced methane could reduce the GHG benefits of this fuel. Leakage of methane during production and transportation also reduce the

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[76] Application of Southwest Gas Corporation for approval of renewable natural gas ("RNG") activity related to purchasing RNG to be included in its supply portfolio, Commission Docket No. 21-01015, Direct Testimony of Dr. Emily Grubert, submitted April 12, 2021, *passim*.

[77] Timmerberg, S., Kaltschmitt, M., Finkbeiner, M. "Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas – GHG emissions and costs." Energy Conversion and Management: X. Vol. 7, (Sept. 2020), available at https://bit.ly/3E0MaVv

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GHG reduction benefits of SNG. As with biomethane, SNG will have the same leakage rate during end use as fossil gas.

c. Feasibility/scalability and functionality

i.Electrification

As described in the previous section on alternative energy options, electrification technologies are widely available today for a large range of needs, are growing in adoption, and new products are meeting market needs and functions. Heat pumps provide cooling as well and are among the more efficient available cooling equipment. HPWHs can also be used as a demand response resource and can absorb excess renewable energy during off-peak hours.

The electric grid already runs to every building and for most gas customers, the electric panel is already sized to meet cooling load. Thus, electrifying space heating in southern Nevada would likely not require upgrades to the transmission and distribution system in the near term. Over the longer term, as other loads such as transportation are electrified, system upgrades may be needed. In the Reno area, where winter and summer peaks are similar, grid upgrades may be needed sooner.

ii.Hydrogen

Low-emission hydrogen could, in theory, become available at a scale comparable to today's use of fossil gas. Blue hydrogen is produced from fossil gas, while green hydrogen supplies are limited by the availability of electricity. However, there is almost no production of either blue or green hydrogen today, due to their very high cost compared with traditionally-produced hydrogen. As noted above, traditionally-produced "grey" hydrogen has virtually no GHG emissions benefits over other types of fossil fuel sources. Thus, the development of the "green" hydrogen market, in particular, will be key to hydrogen's utility as a zero-carbon fuel alternative.

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The U.S. Department of Energy's hydrogen program has set a goal of reducing the cost of green hydrogen production from today's $5 per kg to $1 per kg by 2030. Falling cost of renewable electricity inputs will contribute to this goal as will improvements in electrolyzer efficiency and cost. However, even at $1 per kg, green hydrogen would still cost $8.79 per MMBTU (88 cents per therm), or between two and four times the recent cost of wholesale fossil gas, before accounting for transportation or storage costs. At this price, green hydrogen would be cost-competitive with traditionally produced hydrogen, but it would still have a hard time competing with electricity for end uses that are easily electrified.

Hydrogen may be blended with methane in existing pipes and equipment, up to about 20 percent by volume.[78] However, due to the lower energy density of hydrogen gas, this is only 7 percent by energy delivered. This means that even zero-carbon hydrogen could reduce pipeline gas emissions by just 7 percent before requiring equipment and pipeline changes. Hydrogen molecules are smaller than methane and would be as much or more prone to leaking from older pipes as methane. In addition, hydrogen can embrittle some metal pipe materials, creating safety concerns.[79]

While hydrogen can be transported in many new plastic fossil gas pipes, a transition period would require either two separate sets of infrastructure or for all end uses on a given pipe to transition to hydrogen at the same time. Hydrogen-ready appliances are not widely available today and face engineering and consumer acceptance barriers, as discussed more below. Many customers faced with the need to replace home equipment to burn relatively expensive hydrogen fuel would likely choose electric options.

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[78] Melaina, *et al.*, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*. NREL Technical Report NREL/TP-5600-51995, (2013), Available at: https://bit.ly/3C0XkJt

[79] U.S. Department of Energy, "Safe Use of Hydrogen," (accessed October 20, 2021), available at https://bit.ly/3m1mkL6

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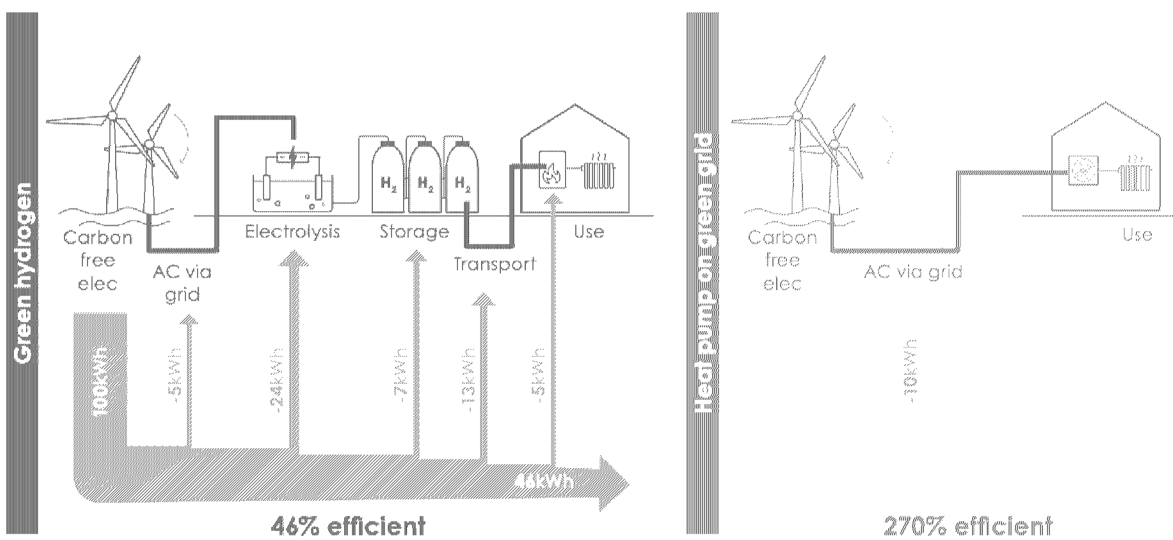
One challenge facing green hydrogen production is the availability of sufficient renewable electricity. Delivering heating service in a home with green hydrogen would require almost six times as much electricity production as delivering the same heat with a heat pump (see Figure 5). Given the challenge of scaling renewable electricity fast enough to meet decarbonization objectives for the grid, it is important to use electricity as efficiently as possible once it is generated. As mentioned above, hydrogen has different combustion properties than methane, so consumers will require different equipment to burn it safely.[80] Figure 5 below demonstrates that it is much more energy efficient to use renewable electricity directly in a heat pump than it is to convert that electricity to hydrogen for use in a combustion appliance.

Figure 5. A comparison of the heat delivered to a living space from 100 kWh of carbon-free electricity using the green hydrogen and heat pump approaches.[81]



[80] See a technical discussion of the issues discussed in Livermore, S., "Exploring the potential for domestic hydrogen appliances" The Engineer (2018), available at https://bit.ly/2Zez34b

[81] London Energy Transformation Initiative, "Hydrogen: A decarbonisation route for heat in buildings?," (2021), available at: https://bit.ly/3G5kuAy

iii. Biomethane

Once processed, biomethane is chemically the same as fossil gas and can be used interchangeably. However, biomethane availability and scalability is quite limited by available biomass feedstocks. As shown in Table 1, ICF's 2019 study for the American Gas Foundation finds that the "high resource" scenario for Nevada would only have in-state production of 18.6 TBtu. ICF's estimate of high potential only amounts to about 20 percent of the state's 2020 consumption of fossil gas for residential, commercial, and industrial end uses (91.11 TBtu).[82]

Table 1. Technical potential supply of biomethane in Nevada in 2040 relative to 2020 fossil gas consumption.[83]

Source	**Tbtu/year**	**Percent**
Landfill gas	8.701	47%
Manure	1.616	9%
Water resource recovery facilities	0.166	1%
Food waste	0.088	0%
Agricultural residues	0.005	0%
Forest residues	1.893	10%
Energy crops	0	0%
Municipal solid waste	6.118	33%
Total	**18.587**	**100%**
Fossil gas consumption in 2020	**91.11**	**20%**

[82] ICF, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," (2019), available at https://bit.ly/3vt4IL7

[83] *Id.*

Importantly, 90 percent of biomethane production under the high resource case would come from landfill gas, gasification of forest waste, and municipal solid waste. These three methods have positive lifecycle GHG emissions, according to the ICF report.[84] Likewise, the lower-cost resources dominating the lower part of the supply curve, generally landfill gas projects and water resource recovery facilities, have positive lifecycle GHG emissions in all other regions of the U.S., including the Mountain region.[85] Biomethane and SNG also pose the same safety challenges as fossil gas,[86] including risk of fires and explosions. In the U.S., local fire departments respond to 4,200 home fires caused by ignition of fossil gas per year. On average, these fires result in $54 million in direct property damage per year, 140 civilian injuries, and 40 civilian deaths.[87] Aside from fire risk, recent studies find significant negative health impacts from burning gas in buildings. In particular, NOx emissions from indoor gas appliances appear to contribute to increased respiratory symptoms and asthma attacks.[88]

iv. Synthetic Natural Gas

Like biomethane, SNG is chemically the same as fossil gas and can be used interchangeably. However, production of SNG first requires energy and cost to generate hydrogen. It also requires a source of carbon. When using fossil-based carbon sources, this fuel would face the same feedstock challenges as biomethane. To replace fossil gas with SNG, the carbon would likely need to be captured from the air using direct air capture ("DAC"), but capturing non-fossil carbon comes with its own cost, energy demand, and uncertainty challenges. The energy inputs to the

[84] Id., Table 41, p. 72.
[85] Id., page 60.
[86] Ahrens, M., and Evarts, B., "Natural Gas and Propane Fires, Explosions and Leaks Estimates and Incident Descriptions," (2018), available at https://bit.ly/3AYpqDF
[87] The National Fire Protection Association, "Natural Gas and Propane Fires, Explosions and Leaks: Estimates and Incident Descriptions," (2018) available at https://bit.ly/3vCjxLw
[88] See, for example, Seals, B., Krasner, A., "Health Effects from Gas Stove Pollution.," (2020) RMI, available at: https://bit.ly/3niS918

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550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

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550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

DAC process could negate the GHG benefit of SNG. For a net reduction in lifecycle GHGs, air capture would need to be powered with zero-carbon sources of energy, and leakage of the produced methane would need to be limited. In addition, use of DAC for producing SNG would compete with DAC for negative emissions, which will be required to meet global Paris Agreement targets. Methane poses the risk of fires and explosions. Similar safety hazards are likely to exist with SNG and biomethane.

d. Equity and the decarbonization of the gas system

i. What equity issues might arise?

Electrification is happening and will continue to happen, even without policy support. As discussed above, heat pumps are currently less expensive than gas heating and air conditioning in new construction and in retrofit situations they have similar annualized costs as compared to a gas furnace and central air conditioner. Heat pumps and other electrified equipment will gain the edge as the costs of electrification technologies continue to decline, new federal carbon policy places value on carbon reductions, and as consumers gain awareness of factors like emissions associated with gas combustion.

Given the superior efficiency of heat pumps relative to gas, electricity cost increases to decarbonize will be smaller than those for combustion fuels. Also favoring electrification, consumers can shift to paying for only one distribution system (the electric grid) via fixed customer charges instead of a redundant second system (the gas distribution system). Recognizing that the benefits of electrification outweigh the costs, households that can afford to electrify—higher-income and wealthier households—will do so. The pace will be faster in the future as the costs of electrified equipment continue to decline and the cost of piped gas delivery increases as more customers leave the gas system.

Without targeted policy interventions, those who are left on the gas system will likely include people who face high barriers to electrification. In particular, this includes households and businesses without access to capital and low-income populations, who generally lack the ability to pay higher up-front costs of electrification. Customers who are not able to make modifications to their homes, such as renters, will be in a similar situation. These groups will bear a larger and larger portion of the sunk costs of the gas transmission and distribution system, as more and more people electrify and the costs of the gas systems are borne by fewer and fewer gas customers.

Because state and national carbon targets will require nearly complete elimination of emissions from the buildings sector, pipelined gas will need to transition to lower-carbon alternatives. Residents who remain on pipeline gas service will also need to pay the higher per-unit costs for low-carbon fuel to burn. This will exacerbate inequities between those with the ability to electrify and those without.

ii. How to protect from these harms/risks?

It will be critical to address equity issues up front before they become unmanageable. As described below, the approaches should include both initiatives and policies targeting historically underserved communities and broader mitigation efforts, consistent with Executive Order 2019-22's call to consider the impact of carbon reduction policies and programs on low-income and disadvantaged communities.[89]

Policies to address electrification in low-income and historically underserved communities should be launched before or in tandem with efforts that target broader populations to avoid making equity problems worse. Targeted programs should start with an assessment of the barriers that disadvantaged populations face with respect to electrification. In addition to challenges with

[89] State of Nevada Executive Department, "Executive Order 2019-22: Order Directing Executive Branch to Advance Nevada's Climate Goals," (2019) available at https://bit.ly/30OnEZv

upfront equipment costs, these may include the inability to make changes to housing (as faced by renters), lack of time to coordinate electrification retrofits, low awareness of options, language barriers, lack of knowledge of the health and safety concerns with gas appliances that can be mitigated with electrification, and others. Programs can directly address the barriers resulting from lack of access to capital by facilitating support from the aggregate customer base to those most in need.

Communities should be engaged and central to the development of decarbonization effort goals and design.[90] To increase trust in the effort, communities should also have a say in metrics for measuring program impact and reporting. Programs that tap trusted community organizations for their outreach and delivery may be more effective than programs administered by utilities or government agencies.

Programs that should be explored with disadvantaged communities include: targeted building shell improvements and low-income weatherization efforts; electrification programs aimed at these communities; and rate subsidy programs paid by other ratepayers or taxpayers. These efforts can be combined; for example, building shell improvements can be coordinated with electrification to produce large comfort and health benefits for residents of lower quality housing stock. Efforts that focus on helping the customers that face the highest barriers to electrification, such as low-income households and renters, are likely to produce the greatest risk reduction. Decisions about which investments to fund through efficiency programs should be informed by cost-effectiveness screening that takes the state's policy priorities into account—including Nevada's carbon reduction targets. Such screening should consider whether a given measure or

[90] Greenlining Institute, "Equitable Building Electrification: A Framework for Powering Resilient Communities," (2019), available at https://bit.ly/3BWyxWK

Conservation Advocates
550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

Conservation Advocates
550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

portfolio is the most cost-effective way to meet the stated policy goal relative to another GHG-compliant baseline, not relative to a baseline that is not compliant.

In addition to efforts targeting disadvantaged populations, efforts should also minimize risks of stranded costs overall. This includes adopting a range of measures to discourage new gas system and equipment investments that may be stranded or be obsolete in the future and put high burdens on disadvantaged customers, such as the following:

- Building performance standards or building codes that achieve GHG emissions reductions, which may require promoting electrification or zero emission fuels instead of simply prescribing efficiency levels of certain equipment[91];
- Mid-stream or upstream incentive programs that can address many barriers to electrification (including lack of knowledge, low awareness of options, lack of time to coordinate electrification retrofits, and upfront equipment costs);
- Implementing rules or laws that set a higher bar, such as appropriately considering the useful life of gas system investments in the context of decarbonization, for Commission approval of gas investments, either extensions or replacements;
- Providing gas utilities with appropriate regulatory guidance on how unused or underutilized assets will be treated to enable them to make the most economic gas investment decisions, and;
- Improving gas planning and integrated electric/gas planning.

[91] As an example of these codes, California recently adopted its 2022 building energy efficiency standards for new and existing buildings. The 2022 codes establish electric heat pumps as a baseline technology and also set requirements that homes be able to support EV charging and electric heating and cooking that will likely lead most new construction to be built without gas connections. California's code is estimated to reduce GHG emissions by 10 million metric tons over a 30-year period. (California Energy Commission, "Energy Commission Adopts Updated Building Standards to Improve Efficiency, Reduce Emissions From Homes and Businesses," (2021), https://bit.ly/3lYsGuo; and 2022 Building Energy Efficiency Standards Summary, https://bit.ly/3DUCpYM.)

Other mitigation policies to reduce the burden on the customers who are last-on-the-system could include accelerated depreciation, securitization of gas assets, and adjusting cost recovery of pipes that are abandoned in place. Accelerated depreciation would spread cost recovery for the gas system across the broader group of customers that is on the gas system today, before substantial defection occurs. Depreciation could be scaled to expected consumption; for example, if 5 percent of the gas that will go through a pipe for the remainder of the pipe's life will go through in one year, then 5 percent of the remaining asset cost should be recovered that year.

If enabled by statute, gas assets can be securitized though a process wherein the state coordinates the buy-out of the assets and taxpayers take responsibility for paying back the bond used to pay for the assets. Securitization may allow shifting costs of gas infrastructure from gas ratepayers to taxpayers or potentially through electric rates, generally at a lower financing rate. Securitization can provide additional flexibility because the bond could be paid over a different period of time than the asset lifetime. While securitization has been used with the retirement of coal power plants, this approach is untested for the slow accumulation of retired assets that make up a large portion of a gas utility's ratebase.[92] Although it did not pass, Nevada's Assembly Bill 380 contemplated securitization to mitigate rate impacts while use of the gas system is declining.

Excluding funds to remove gas assets upon their retirement from depreciated expenses could have a large impact on rates. In addition to the amount invested in the pipe, standard depreciation practice recovers the net cost of removal of the pipe at end of life. Retirement costs are anticipated to occur years in the future. Considering inflation, the costs of removing the asset can equal or exceed the value of the asset itself—doubling or more than doubling depreciation costs. If gas assets can be safely abandoned in place without removal, rate pressures could be reduced.

[92] Synapse Energy Economics, "Gas Regulation for a Decarbonized New York", (2020) available at www.synapse-energy.com.

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550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

4. Conclusion

In sum, the future of the gas distribution system in Nevada must be tied to Nevada's effort to reduce economy-wide emissions to zero to avoid the worst impacts of climate change. While "alternative piped fuels" exist, such as RNG and SNG, the availability of those fuels is anemic compared to Nevada's abundant solar and geothermal electricity resources, and other regional wind resources. Nevada has numerous alternatives that support a fully decarbonized grid through electrification. The Commission should review the best models, such as the Pathways reports, throughout the remainder of this investigation and possibly examine the role an independent third party could play in looking at the carbon future of Nevada. The Conservation Advocates look forward to other parties' comments and continued participation throughout the remainder of this investigation.

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Respectfully submitted,

Cameron Dyer, Esq.
Nevada Bar No. 14364
Western Resource Advocates, Staff Attorney
550 West Musser Street, Suite I
Carson City, NV 89703
(775) 430-4632
cameron.dyer@westernresources.org

/s/ Dylan Sullivan
Senior Scientist,
Climate & Energy Program
Natural Resources Defense Council
111 Sutter Street, 21st Floor
San Francisco, CA 94104

/s/ Ellen Zuckerman
Ellen Zuckerman
Utility Program Co-Director, SWEEP

/s/ Elspeth Cordua
Elspeth Cordua, Beyond Coal Campaign Representative
Sierra Club

/s/ Paul Selberg
Paul Selberg, Executive Director
Nevada Conservation League

Conservation Advocates
550 West Musser Street, Suite G, Carson City, NV 89703-4997 – 775-430-4633

ATTACHMENT 1
Conservation Advocates Comments

CALIFORNIA
ENERGY COMMISSION

Energy Research and Development Division

FINAL PROJECT REPORT

The Challenge of Retail Gas in California's Low-Carbon Future

Technology Options, Customer Costs, and Public Health Benefits of Reducing Natural Gas Use

Gavin Newsom, Governor
April 2020 | CEC-500-2019-055-F

PREPARED BY:

Primary Authors:
Dan Aas, Amber Mahone, Zack Subin, Michael Mac Kinnon, Blake Lane, Snuller Price

Additional contributors: Doug Allen, Charles Li, Gabe Mantegna

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
415-391-5100
www.ethree.com

University of California, Irvine, Advanced Power and Energy Program
Engineering Laboratory Facility
Irvine, California 92697-3550
949-824-7302
http://www.apep.uci.edu

Contract Number: PIR-16-011

PREPARED FOR:
California Energy Commission

Guido Franco and Susan Wilhelm, Ph.D.
Project Managers

Jonah Steinbuck, Ph.D.
Office Manager
ENERGY GENERATION RESEARCH OFFICE

Laurie ten Hope
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Drew Bohan
Executive Director

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division manages the Natural Gas Research and Development program, which supports energy-related research, development, and demonstration not adequately provided by competitive and regulated markets. These natural gas research investments spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

The Energy Research and Development Division conducts this public interest natural gas-related energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public and private research institutions. This program promotes greater natural gas reliability, lowers costs, increases safety for Californians, and is focused in:

- Buildings End-Use Energy Efficiency.
- Industrial, Agriculture, and Water Efficiency.
- Renewable Energy and Advanced Generation.
- Natural Gas Infrastructure Safety and Integrity.
- Energy-Related Environmental Research.
- Natural Gas-Related Transportation.

The Challenge of Retail Gas in California's Low-Carbon Future is the final report for the future of natural gas project (PIR-16-011) conducted by Energy and Environmental Economics and the University of California, Irvine. The information from this project contributes to the Energy Research and Development Division's Natural Gas Research and Development Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at 916-327-1551.

ABSTRACT

This study evaluates scenarios that achieve an 80 percent reduction in California's greenhouse gas emissions by 2050 from 1990 levels, focusing on the implications of achieving these climate goals for gas customers and the gas system. Achieving these goals is not guaranteed and will require large-scale transformations of the state's energy economy in any scenario.

These scenarios suggest that building electrification is likely to be a lower-cost, lower-risk long-term strategy compared to renewable natural gas (RNG, defined as biomethane, hydrogen and synthetic natural gas, methane produced by combining hydrogen and carbon). Furthermore, electrification across all sectors, including in buildings, leads to significant improvements in outdoor air quality and public health. A key uncertainty is whether consumers will adopt electrification technologies at scale, regardless of their cost effectiveness.

In any low-carbon future, gas demand in buildings is likely to fall because of building electrification or the cost of RNG. In the High Building Electrification scenario, gas demand in buildings falls 90 percent by 2050 relative to today. In the No Building Electrification scenario, a higher quantity of RNG is needed to meet the state's climate goals, leading to higher gas commodity costs, which, in turn, improve the cost-effectiveness of building electrification.

The potential for large reductions in gas demand creates a new planning imperative for the state. Without a gas transition strategy, unsustainable increases in gas rates and customer energy bills could be seen after 2030, negatively affecting customers who are least able to switch away from gas, including renters and low-income residents.

Even in the High Building Electrification scenario, millions of gas customers remain on the gas system through 2050. Thus, this research evaluates potential gas transition strategies that aim to maintain reasonable gas rates, as well as the financial viability of gas utilities, through the study period.

Keywords: Natural gas, greenhouse gas emissions, climate change, renewable natural gas, electrification, equity, air quality and public health

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EXECUTIVE SUMMARY

Introduction

This research evaluates scenarios that achieve an economywide reduction in greenhouse gas (GHG) emissions of 40 percent by 2030 and 80 percent by 2050 from 1990 levels. California has also set a carbon-neutral target for 2045, which is not directly evaluated as part of this research.

Natural gas is an integral part of California's energy system, including in buildings, industry, and electric generation. Nearly 80 percent of all homes in California are connected to the natural gas system. Californians spend nearly $14 billion per year on gas, both to use the gas itself in buildings, industry, and electric generation and to maintain and operate the gas system.

To meet California's climate goals, use of fossil fuels like natural gas will need to decrease by 80 percent or more by 2050. Zero-carbon electricity requirements under Senate Bill 100 (de León, Chapter 312, Statutes of 2018) will lead to a substantial reduction in annual demands for natural gas in electric generation. Efforts to reduce built environment emissions, particularly strategies to reduce GHG emissions from natural gas use in buildings via efficiency or electrification, could also lead to reductions in natural gas demand over time. However, no Energy and Environmental Economics, Inc. (E3) study has yet identified a strategy that eliminates the use of pipeline gas altogether, since zero carbon gas alternatives can replace natural gas in the pipeline. Every scenario leaves residual gas demands in industry, while others allow gas usage in the buildings or transportation sector.

The implication is that any scenario that meets California's climate policy goals uses some amount of renewable natural gas (RNG). The research team defines RNG as climate-neutral gaseous fuels and uses it as an umbrella term to encompass four fuels, including 1) biomethane produced from anaerobic digestion of biomass wastes, 2) biomethane produced from gasification of biomass wastes and residues, 3) climate-neutral sources of hydrogen gas, and 4) methane produced synthetically from a climate-neutral source of carbon and hydrogen. (*Gasification* is a technology that converts carbon-containing materials, including biomass, into synthetic gas.) This study finds that, at scale, the costs of these fuels far exceeds that of natural gas. Relatively inexpensive portions of biomethane RNG are limited in quantity, so it may be preferable to reserve the use of these supplies for more energy-intensive, trade-exposed sectors of the California economy that do not have efficient, electrified substitutes readily available.

The question of the future of retail gas – defined here primarily as gas usage in the buildings sector – hinges on cost and consumer acceptance. Electrification, the use of electricity in place of other fuels, appears to be a cost-effective strategy for some consumers today. The addition of relatively high cost RNG into the gas pipeline would improve the economics of electrification in buildings. If demand for natural gas in California falls dramatically because of some combination of policy and economically driven electrification, the fixed costs to maintain and operate the gas system will be spread over a smaller number of gas sales and, ultimately, will increase costs for remaining gas customers. This outcome raises the possibility of a feedback effect where rising gas rates caused by electrification spur additional electrification. Such a feedback effect would threaten the financial viability of the gas system, as well as raise substantial equity concerns over the costs that remaining gas system customers would face. Given these risks, building electrification could serve as a risk-reduction strategy to protect low-income and vulnerable communities from future gas rate increases. However, achieving meaningful levels of building electrification will require changes to both new construction practices as well as retrofits of the existing building stock. Consumer adoption of building electrification technologies is one the largest barriers to achieving the emissions reductions from the building sector described in the High Building Electrification scenario.

If building electrification is delayed, missing the lower-cost opportunities for all-electric new construction and replacement of equipment upon failure, there is a greater risk that expensive early retirement of equipment may be needed, or that the climate goals could be missed. Furthermore, there are significant technology and cost risks of commercializing large quantities of renewable natural gas compared to electrifying buildings, which relies on technologies that are commercialized today.

This analysis, and work by others, suggests that achieving the state's ambitious climate goals is possible, but is far from assured, requiring rapid and near-term transformation in all sectors of the economy, as well as widespread consumer adoption of low-carbon technologies, fuels and practices.

Project Purpose

The future of natural gas, in the context of meeting the state's climate goals, is an important question for natural gas and electric ratepayers, as well as for policymakers interested in enabling California's clean energy transition. The research team takes a forward-looking view of future gas use in California, focusing on implications for, and strategies to protect, ratepayers.

To do that, this research evaluates the potential cost, energy infrastructure, and air quality implications of achieving the state's economywide climate goals, with an emphasis on:

1) Technology options to decarbonize the natural gas system. Specifically, what are the costs, and resource potential, for renewable natural gas technologies, including biomethane, hydrogen gas and climate-neutral synthetic natural gas?
2) Implications for natural gas customers. What are the potential changes in natural gas demand, rates, and bills associated with meeting California's climate goals? What are potential strategies to address the equity implications of changes in natural gas rates and utility bills while maintaining the safety and financial viability of the gas system?
3) Outdoor air quality and public health. What are the outdoor air quality and health benefits of meeting California's climate goals, and what are the air quality implications of reducing GHG emissions from natural gas?

The purpose of this research is not to define or recommend policies nor provide a definitive set of conclusions about California's energy future. Instead, the research team strives to use the best information available today to provide insights about how the decisions made today could affect the state's future choices. Those insights will inform researchers and policy makers on potential next steps toward achieving the state's clean energy transition.

Project Approach

E3 and the Advanced Power and Energy Program at the University of California, Irvine, (UCI) comprise the research team.

E3 led the development of economywide GHG scenarios using the California PATHWAYS model, as well as a detailed evaluation of the long-term natural gas rate and bill impacts of those scenarios. The California PATHWAYS model is a technoeconomic model of the state's energy consumption and GHG emissions that has been used and updated by California energy agencies since 2014.

The GHG mitigation scenarios evaluated in the PATHWAYS model do not represent forecasts of what is likely to happen, but rather represent "back-casts" of what kinds of changes, on what timeframe, may be necessary to meet a long-term climate goal.

E3's natural gas utility revenue requirement tool estimates how changes in natural gas demand throughput and changes in gas commodity costs could affect natural gas rates, both over time and by customer class. The revenue requirement tool was developed specifically for this project and benefited from insights and detailed feedback provided by the Southern California Gas Company (SoCalGas) and Pacific Gas and Electric (PG&E) and relied exclusively on publicly available data. Neither SoCal Gas nor PG&E was asked to endorse the revenue requirement tool or the study findings, which remain entirely the responsibility of the study team.

The UCI Advanced Power and Energy Program team worked with E3 to develop bottom-up estimates of RNG technology production costs using conservative and optimistic assumptions about technology learning curves, as well as other key input parameters.

The UCI team also led the analysis of outdoor air quality and health impacts of achieving the state's climate goals. The UCI team used the California PATHWAYS scenarios as the basis for assumptions about future changes in energy demand by fuel type and equipment type over time. The UCI team employed a sophisticated set of air quality modeling tools, including Sparse Matrix Operator Kerner Emissions (SMOKE) to resolve the emissions spatially by geography, the Community Multiscale Air Quality Modeling System (CMAQ) to simulate air quality, and the Environmental Benefits Mapping and Analysis Program (BenMAP) to estimate the health savings effects.

The project team benefited from in-kind labor contributions from the Sacramento Municipal Utilities District (SMUD) and SoCalGas, who both participated on the Technical Advisory Committee (TAC) and provided other data and feedback to the research team. SoCalGas also cofunded a portion of UCI's research. Other members of the TAC included representatives from PG&E; the California Air Resources Board; University of California at Riverside; University of California at Davis; the Natural Resources Defense Council; the Environmental Defense Council; Mitsui and Co.; and the Greenlining Institute. For a complete list of TAC members, see Appendix B.

Key areas of discussion and debate among TAC members and the research team included the following:

1. How to reflect the costs and uncertainties around wildfire risk in California?

2. How to assess the future resource potential for biomass and biofuels available to California?
3. How to reflect current state programs that encourage through incentives the use of biofuels, electricity, and hydrogen in the transportation sector, particularly the Low Carbon Fuel Standard?
4. How to characterize the most likely future trajectory for hydrogen gas and synthetic natural gas production costs?

Each one of these topics was evaluated in the course of this research as described in this report and in the Appendices. For a more detailed discussion of some of the "frequently asked questions" and comments about this report, see Appendix A.

Participation on the TAC was voluntary and in no way indicates that TAC members endorse the study conclusions. In addition to participating in the TAC meetings, the TAC members, as well as many other organizations and members of the public, submitted formal comments on the draft study findings, and again on the draft report. While all the comments provided by the TAC members and other stakeholders were considered, this research remains an independent research project, and the study authors are solely responsible for the contents of the report.

Project Results

This study evaluates the cost and resource potential for biomethane, hydrogen and synthetic natural gas, collectively, renewable natural gas. Of these three gases, biomethane is the most commercialized and is lowest cost, but is limited in availability based on sustainable sources of biomass feedstock. Hydrogen and synthetic natural gas could be produced with low-cost electricity that might otherwise be considered "over-supply" and curtailed, but the quantity of this low-cost electricity is far lower than the amounts of electricity that would be needed to produce large enough quantities of hydrogen and renewable natural gas to replace natural gas use in California. Hydrogen use in the natural gas pipeline is limited to 7 percent by energy, before costly pipeline upgrade costs would be incurred to transport higher concentrations of the gas. Even under optimistic cost assumptions, the blended cost of hydrogen and synthetic natural gas is 8 to 17 times more expensive than the expected price trajectory of natural gas.

Renewable natural gas is found to be a valuable, but relatively expensive from of carbon reduction. Relatively low-cost biomass feedstocks are limited in quantity, so lower-cost PATHWAYS scenarios allocate these limited feedstocks to sectors that are difficult to electrify, like aviation, industry, and trucking. The limited supply of and competing uses for biofuels mean that scenarios that maintain high volumes of gas throughput in buildings require hydrogen and synthetic natural gas to reduce emissions.

In all the long-term GHG reduction scenarios evaluated here, electrification of buildings, and particularly the use of electric heat pumps for space and water heating, leads to lower energy bills for customers over the long term than the use of renewable natural gas. Likewise, building electrification lowers the total societal cost of meeting California's long-term climate goals. The High Building Electrification scenario is lower cost than the No Building Electrification scenario in 2050 by $5 billion to $20 billion per year (in 2018 dollars). The primary reason for this cost difference is the cost of decarbonizing natural gas with renewable natural gas, relative to electrification buildings. Furthermore, in the No Building Electrification scenario, a larger amount of fossil fuel emissions remain in buildings, which means that more expensive GHG mitigation measures, such as additional zero-emission trucks, are needed elsewhere to meet the economywide climate goal.

This strategy, of leaving more fossil fuel emissions in the building sector in order to minimize the reliance on expensive RNG, may not be possible in a scenario that achieves the state's 2045 carbon-neutrality goal. Achieving carbon neutrality in buildings would likely increase the relative costs of high RNG scenarios, such as the no building electrification scenario, compared to scenarios relying on building electrification.

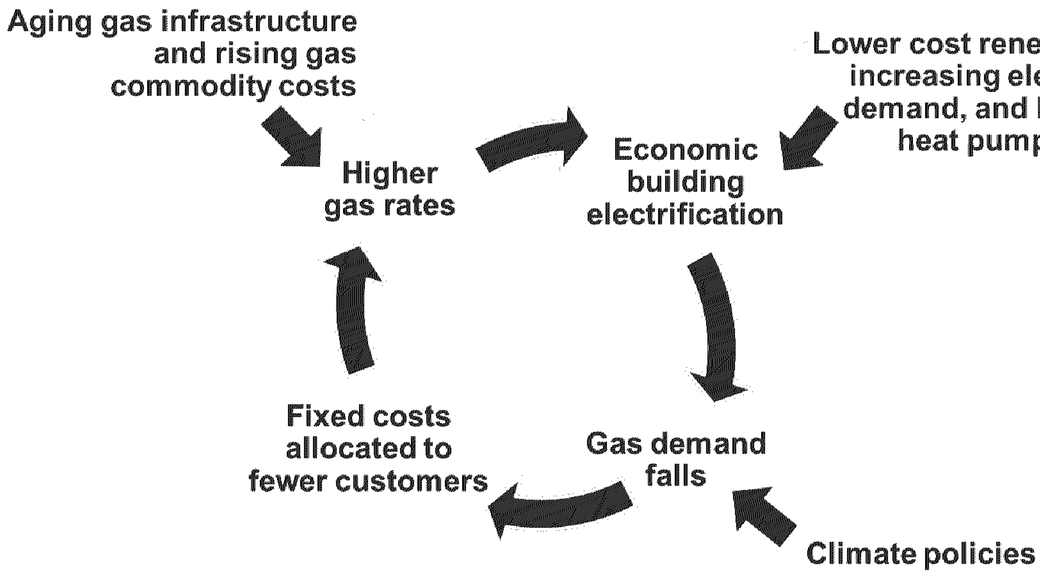
Building electrification is found to improve outdoor air quality and public health outcomes, particularly in the winter, when nitrogen oxide emissions create secondary fine particulate matter (PM 2.5) pollution in the Central Valley. Electrification in other sectors, including transportation and industry, also shows dramatic improvements in outdoor air quality.

In all scenarios, the cost of maintaining the electric grid, including the costs of wildfires and upgrades to the electric grid to prevent future wildfires, are expected to increase, even those scenarios with low building electrification. While is it uncertain what the magnitude of these electricity sector costs will be, wildfire adaptation costs are not expected to vary by scenario, so would not impact the net scenario costs, which are reported relative to the reference scenario. This study finds that the addition of new electric loads, in the form of electric vehicles and building electrification, helps mute these cost impacts on electric rates. Furthermore, these new electric loads offer the possibility to provide flexibility to the grid, which could help to reduce the cost of decarbonized electricity. Higher electricity costs will affect the relative customer economics of electricity versus RNG, so a wide range of potential electricity and gas system costs are explicitly evaluated. The economic results are found to be robust across a wide range of electricity and RNG costs.

In all of the scenarios evaluated here, some gas consumers will find it in their economic self-interest to electrify. Electrification is likely cost effective for large subsets of Californians today, so higher gas commodity costs only expand the set of end-uses and customer types that would find electrification advantageous. In any future where California meets its long-term climate goals, natural gas demand is likely to decline, putting upward pressure on gas rates and bills. That pressure may cause more customers to exit the gas system, as a feedback loop takes effect (Figure ES-1). The prospect of such a feedback loop makes it prudent for the state to begin considering strategies for managing the costs of the natural gas distribution system in California.

The decline in gas demand in all scenarios meeting the state's climate goals, and especially in the High Building Electrification scenario, poses significant challenges to maintaining equitable cost allocation. Residential customers pay most of the costs of the gas distribution system. The gas distribution system constitutes the majority of the book value of both California's major natural gas utilities. As residential customers exit the gas system, those costs are spread over a smaller quantity of throughput and number of customers, leading to increased rates for remaining customers. Absent a policy intervention, low-income customers who are less able to electrify may face a disproportionate share of gas system costs.

Figure ES-1: Outside Forces in the Natural Gas Delivery Sector Could Lead to Lower Gas Demand and Higher Rates in Future Greenhouse Gas Reduction Scenarios



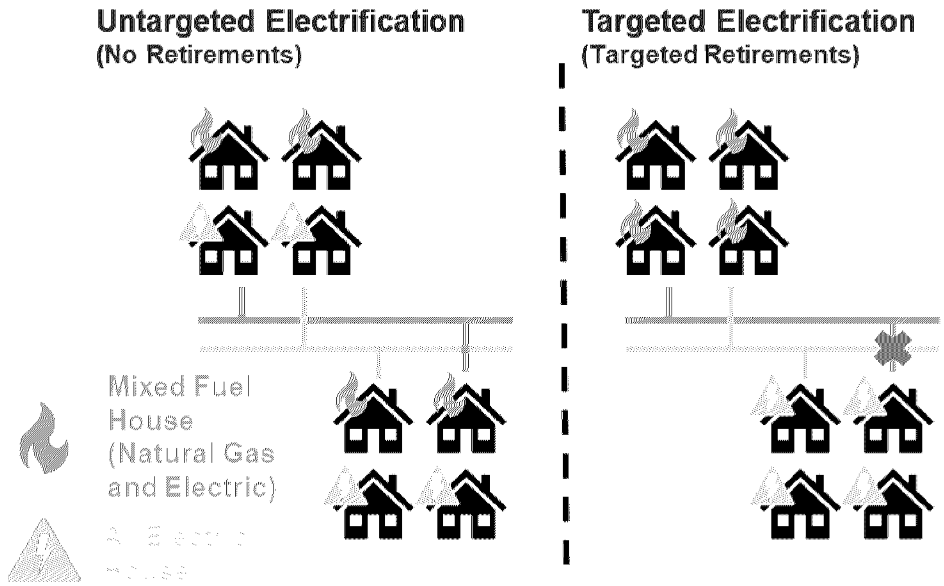
Source: E3

It is important for the state to consider a gas transition strategy to ensure that, even as gas demand falls, the system remains safe and reliable for the remaining gas customers while helping reduce future customer cost and utility bill impacts, as well as addressing equity challenges. Even in the High Building Electrification Scenario, which assumes a rapid transition to 100 percent of sales of all new water heaters and HVAC systems to electric heat pump equipment by 2040, there are still millions of gas customers remaining in California by 2050. Early retirement of gas equipment could speed the pace of this gas transition but would come with real economic costs that are difficult to estimate at this time. In addition, early retirement of gas equipment would likely face other challenges, including customer adoption barriers.

Given the long lifetimes of buildings and building equipment, a complete gas transition is likely to require decades in any scenario. For these reasons, this research evaluates potential gas transition strategies that aim to maintain reasonable gas rates, as well as the financial viability of gas utilities through the study period. Legal and legislative options, including strategies for a more rapid transition away from gas, are not evaluated.

A well-managed gas transition could enable cost reductions of gas infrastructure investments, as well as some reductions in gas system operations and maintenance costs that would be incurred in the absence of a gas transition strategy. Such a managed gas transition would likely require some amount of targeted or zonal electrification, to enable a reduction in the gas distribution infrastructure (illustrated on the right side of Figure ES-2). Without a managed gas transition and without any effort to target electrification, it would be difficult to reduce the size or scale of gas system investments and costs (illustrated on the left side of Figure ES-2). Additional research is needed to better understand the geographic scope, scale, pace, and limitations to reducing gas distribution system costs.

Figure ES-2: Two Gas System Futures With and Without Targeted Electrification



Source: E3

A further reason a structured gas transition is needed is that high-pressure gas transmission and underground gas storage systems may continue to serve important roles, even in a scenario with an 80 percent or higher reduction in GHG emissions. Those roles might include serving either natural gas or decarbonized gaseous fuels to remaining electric generation, industrial customers, compressed natural gas (CNG) trucks and other CNG transportation options, as well as potentially providing benefits via distributed hydrogen fuel cells. A comprehensive analysis of the role of distributed fuel cells or the uses for the bulk gas system in a carbon-neutral future is beyond the scope of this analysis and is an area that deserves further investigation. However, each of these uses would need to rely on an increasing share of RNG to meet the state's climate goals, rather than continued reliance on fossil natural gas.

A structured gas transition could help ensure the continued viability of gas infrastructure assets that the state needs to maintain reliable energy service, while phasing down investments in gas distribution assets that become too costly to maintain as demand for retail gas declines. If the results of this research are correct in concluding that retail gas in a low-carbon future is likely to be more expensive than building electrification, it raises a number of challenging questions and areas recommended for additional research. Key policy questions include the following:

- If demand for retail gas declines, how should the benefits and costs of a gas transition strategy be allocated among stakeholders?
- If demand for retail gas declines, how can California protect low-income residents and gas workers during a gas transition?

Key engineering questions around gas pipeline safety and costs remain as well. These questions include the following:

- To what degree can targeted electrification efforts safely reduce gas distribution expenditures?

- What is the cost of targeted electrification, considering the potential for early retirements of consumer equipment? A better understanding is needed of the real-world technical and economic options to reduce gas system expenditures. Pilots and real-world research could help identify the costs and options to launch targeted electrification in communities in such a way that would enable targeted retirements of the gas distribution system and consider the impacts on the electric distribution system of targeted electrification, along with the potential for cost savings on the gas distribution system.

Finally, more research is needed to identify the legal and regulatory barriers to implementing a gas transition strategy, along with targeted electrification programs. For example:

- Should natural gas companies be able to collect the entire value of their gas system assets through 2050 or beyond? Should shareholder return be affected in a gas transition strategy? How does the timing of a gas transition strategy affect the answer to these questions?
- Should California gas utilities' obligation to serve be redefined?

This research paper does not seek to make policy recommendations, but rather highlight key issues for further policy discussion. The paper also seeks to illuminate some of the implications of meeting the state's climate goals, with the goal that California's future is as equitable and well planned as possible.

Knowledge Transfer

The CEC has taken steps to ensure that a broad audience has the opportunity to comment on the draft results of this research. The Commission held a public staff workshop June 6, 2019. More than 30 unique public comments were filed to the docket. Additional public comment was solicited by the CEC on the draft report.

Some stakeholders have argued that California should move faster on meeting its climate goals compared to the scenarios evaluated in this study, phasing out the use of all natural gas as quickly as possible due to concerns over combustion emissions, indoor and outdoor air quality concerns, and the prospect of methane leakage—a high global warming potential gas. Other stakeholders have highlighted the uncertain mix of climate change impacts on the future costs of electricity in California. Wildfires, flooding, and extreme heat mean that the provision of reliable and low-cost energy services in the state is becoming more complex and challenging.

The research team envisions this project as a contribution to the continued conversation that stakeholders and policy makers will have over the next several years, as the state considers what steps will be needed to meet the goal of economywide carbon neutrality by 2045, and how to expedite a gas transition strategy that ensures an equitable transition to a low-carbon future for all California residents.

Benefits to California

This project highlights the need for long-term planning for the natural gas system in the context of meeting the state's climate goals. This project provides a long-term, scenario-based view to investigate how the natural gas system can help California meet its long-term GHG reduction goals. Specifically, this project benefits California by providing:

- Information to help lower the costs of meeting California's climate goals and to inform technology research and investment. By taking a long-term view of the state's climate goals and evaluating the role of the natural gas infrastructure in that future, this research allows the state to potentially avoid stranded assets in the gas system. Stranded assets are investments which are not used and useful, and for which the full investment cost cannot be recovered from ratepayers, triggering a premature write-down or devaluation. This project provides information about the potential for changes in natural gas demand and implications for future investments in the gas sector, the gas system rate base, natural gas prices (wholesale and retail), customers' home energy bills, costs of GHG reduction, and capital and fuel costs by sector.
- Energy metrics to make better planning easier. Long-term scenarios provide information on economywide energy use by sector and industry, including energy demand for electricity and natural gas.
- Environmental and public health metrics. This project evaluates long-term, detailed criteria air emissions and pollutant levels statewide at a 4x4 kilometer grid within the context of meeting the state's climate goals. By identifying scenarios that can provide cleaner air and improve public health, policy makers can develop policies to enable a future with cleaner air for Californians and particularly for environmental justice communities with a greater pollution burden.

CHAPTER 1: Introduction

California has a long-standing commitment to reducing greenhouse gases (GHGs) and combating climate change. The state's original climate change mitigation goals, set during Governor Arnold Schwarzenegger's tenure in 2005, aimed to reduce emissions to 1990 levels by 2020 and reduce GHGs by 80 percent below 1990 levels by 2050 (EO S-03-05). The 2020 goal was codified into law in 2006 in Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), while the 2050 goal remains an executive order.

A decade later, Governor Edmund G. Brown Jr. set a 2030 climate target for the state when he signed Senate Bill (SB) 32 (Pavley, Chapter 249) in 2016, requiring the state to reduce GHGs 40 percent below 1990 levels. In 2018, Governor Brown called for the state to achieve carbon neutrality by no later than 2045 (EO B-55-18). The carbon neutrality goal is in addition to the state's 80 percent reduction goal for GHG emissions.

This research project was defined before Governor Brown issued the 2018 carbon neutrality executive order, so the scenarios evaluated here focus on investigating futures that achieve a 40 percent reduction in GHGs by 2030 ("40 x 30") and an 80 percent reduction in GHG emissions by 2050 ("80 x 50"). To meet the state's carbon-neutrality target by 2045, it is safe to assume that most of the mitigation measures modeled here will be needed, as well as additional measures like negative emissions technologies that are not considered in this analysis. While more research is needed to understand the full scope and scale of actions needed to achieve carbon neutrality in California, the research findings presented here serve as a useful guidepost.

California's energy and climate policies extend beyond emissions targets. California law requires the state to achieve a 60 percent Renewables Portfolio Standard (RPS) by 2030 and meet 100 percent of retail sales from zero-carbon electricity by 2045 (SB 100, de León, Chapter 312, Statutes of 2018). Complementary to electric sector decarbonization goals are mandates and targets aimed at increasing the share of zero-emission vehicles on California roads. The state's energy transition also extends to the built environment. Recent legislation (AB 3232, Friedman, Chapter 373, Statutes of 2018) requires the California Energy Commission to examine strategies to reduce emissions from buildings 40 percent below 1990 levels by 2030. These and other policy mechanisms are moving California toward achievement of the state's long-term decarbonization requirements and targets.

This study evaluates and synthesizes the potential impacts of technology innovation, along with California's many long-term energy and climate policies, that are acting on the natural gas sector in California through 2030 and 2050. This research focuses particularly on impacts to retail gas delivered through the natural gas distribution system, the low-pressure system of pipelines that serve most homes and businesses in California. Other research (for example, Long, 2018; Ming, 2019) has evaluated the role of gas on the higher-pressure, bulk gas distribution system.

This project builds on recent studies pertinent to the future of the natural gas industry in California. These studies include recently completed California Energy Commission (CEC)

Electric Program Investment Charge - (EPIC) funded research into the impacts of climate change on temperature and hydroelectric availability in California, as well as the development of long-term scenarios of California's energy sector through 2050.

This study leverages Energy and Environmental Economics' (E3's) expertise in modeling long-term, low-carbon scenarios for the State of California using the California PATHWAYS model. In 2015, the CEC, California Public Utilities Commission (CPUC), California Air Resources Board (CARB) and California Independent System Operator (California ISO) engaged E3 in a joint effort to use the PATHWAYS model to develop statewide greenhouse reduction scenarios through 2050. E3 evaluated several low-carbon scenarios, including a "low-carbon gas" scenario that included the use of biomethane, hydrogen, and synthetic methane in buildings and industry, as well as the use of renewable compressed natural gas (CNG) in trucks. The PATHWAYS model has been further developed for use in CARB's Scoping Plan Update[1] and through support from the CEC's EPIC research program. However, none of those past studies have fully addressed the question of "what is the future of retail natural gas in California?"

The present study also builds on past work by synthesizing technical, economic, and achievable resource assessments of advanced biofuels and low-carbon technologies. Some of these studies had a high-level focus on the potential for synergies between natural gas and renewable electricity (Pless, 2015) without in-depth research on the potential advanced alternatives or the technical and economic aspects. Other studies had deep analysis of particular technologies (Melaina, 2013) or the potential feedstocks and conversion technologies without a focus on the potential for decarbonization of the natural gas system (DOE, 2016; McKendry, 2002).

This project builds on E3's 2018 report to the CEC titled *Deep Decarbonization in a High Renewables Future* (Mahone et al, 2018). That report modeled ten scenarios that all meet California's 2030 targets of a 40 percent reduction in GHGs below 1990 levels and an 80 percent reduction in GHGs below 1990 levels by 2050. A key finding of that study is that electrification is among the lower-cost, lower-risk strategies to decarbonize the buildings sector, given the cost and resource supply limitations associated with low-carbon gas. Informed by this approach, deep decarbonization in the buildings sector was recommended to avoid more expensive or speculative mitigation options elsewhere in the economy.

However, the 2018 study focused on economywide metrics[2] and did not evaluate in-depth what the implications of building electrification, or technology innovation in low-carbon gas technologies, would mean for the natural gas sector or natural gas customers in the state. This study takes a closer look at the distributional implications of building decarbonization in the context of the same 2030 and 2050 California GHG reduction targets. Of particular interest

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1 California Air Resources Board. November 2017. *California's 2017 Climate Change Scoping Plan*, https://ww3.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

2 A total resource cost perspective captures the net costs of California's energy system relative to a reference scenario. This metric includes expenditures on infrastructure (for example, power plants, trucks, heating, ventilation, and air-conditioning [HVAC] equipment) and fuels (for example, jet fuel, biodiesel, renewable natural gas). This perspective does not, however, capture potential distributional implications of different GHG mitigation options on customers.

are the impacts of building decarbonization strategies on households' energy bills and the gas utilities themselves.

This project examines several aspects of strategies to decarbonize buildings in an economywide context. This examination included working with UC Irvine to look into a range of costs for renewable natural gas; a detailed analysis of the gas utility financials and rate impacts of low-carbon scenarios (for example, using a gas utility revenue requirement model); an examination of the consumer bill effects that follow; and an examination of potential gas system transition strategies.

This project asks three main research questions:

1) What are the technology options and potential costs to reduce GHG emissions from natural gas consumption in California?
2) What are the natural gas rate and utility bill implications of different strategies to reduce GHG emissions from natural gas use in California?
3) What are the air quality benefits and human health implications of different electrification and decarbonization strategies?

Technical Advisory Committee and Public Comments

The preparation of this report benefited from a wide range of inputs and perspectives throughout the study development and presentation of draft findings. The Technical Advisory Committee (TAC) members for this project listed in Appendix B represent a wide and diverse range of viewpoints on the topics covered by this research. More than 30 unique comments were filed as part of the public comment period on the draft study results, including comments from more than 200 Sierra Club members. In addition to written comments, many public comments were provided verbally in the staff workshop on June 6, 2019, and filed with the CEC in response to the draft report. Overall, the key areas of discussion and disagreement include:

- The pace and urgency of electrifying buildings as a decarbonization strategy.
- The availability and cost of biomass resources to produce biofuels as an alternative to rapid electrification in buildings.
- The availability and cost of hydrogen as an alternative to rapid electrification in buildings.
- The impact of wildfires and wildfire liability on the future cost and reliability of electricity.

This report does not represent a consensus document on these issues, and many areas of disagreement remain. However, the researchers have seriously considered all the comments provided by stakeholders and have responded to some of these comments directly in this report and to other comments in a "frequently asked questions" document in Appendix A.

Methods

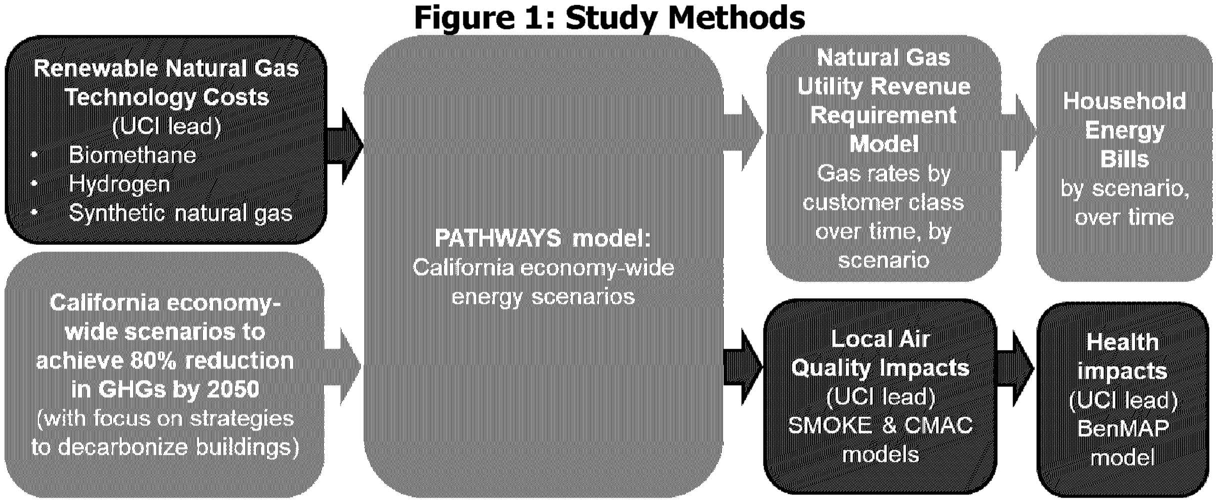
This research involved several phases of analysis steps, as illustrated in the figure below.

First, E3 worked with the University of California, Irvine (UCI) APEP (Advanced Power and Energy Program) (together, the research team) to develop assumptions for future costs and efficiencies of different biofuel conversion processes. APEP also conducted a technoeconomic assessment of power-to-gas pathways to produce renewable natural gas. That analysis examines a variety of different processes to produce hydrogen and synthetic natural gas. The result of that analysis is a conservative case and an optimistic case for the cost of electrolytic fuels ("power to gas").

The research team used these gas technology cost assumptions as inputs to the E3 California PATHWAYS Model. The authors' PATHWAYS model is used to develop economywide mitigation strategies that meet the state's climate policy targets using different combinations of mitigation measures. PATHWAYS is an energy infrastructure, energy and emissions counting model. A key source of variation in the PATHWAYS scenarios evaluated in this study is the blend of pipeline gas and the quantity of gas that is decarbonized.

Using the energy demand outputs from the PATHWAYS model, E3 evaluated how changes in natural gas demand by sector could affect natural gas utility revenues, gas rates, and customer energy bills. To perform this analysis, E3 developed the Natural Gas Revenue Requirement Tool (RR Tool). The RR Tool tracks utility capital expenditures, depreciation, and operational costs given user-defined scenario inputs, including changes in natural gas consumption by sector (from PATHWAYS scenarios), gas equipment reinvestment and depreciation schedules, cost allocation assumptions and the utility cost of capital, among other financial criteria. The tool is benchmarked to general rate case (GRC) filings from Southern California Gas Company (SoCalGas) and Pacific Gas and Electric Company (PG&E),[3] the state's two largest gas distribution utilities. The tool returns gas rates by customer class through 2050. It also includes the ability to model potential gas transition scenarios to reduce the customer bill impacts, as an illustration of some of the strategies that might be considered in more detail going forward.

Figure 1: Study Methods



Source: E3

E3 also developed a bill impacts calculator. The residential customer utility bill calculations in this analysis combine estimates of future electricity rates and gas commodity costs from the

3 The research team relied on the following regulatory filings to build and benchmark the revenue requirement models: PG&E GCAP 2018, PG&E GRC 2020, PG&E GTS 2019, SCG TCAP 2020, SCG GRC 2019, SCG 2017 PSEP Forecast Application, SCG PSEP Forecast application.

PATHWAYS model with gas delivery rates from the RR Tool. The result is a comparison of future utility bills for an "all-electric" and "mixed-fuel" customer in each scenario.

Finally, the UCI APEP team used the PATHWAYS scenario results to inform a detailed air quality and health impacts analysis. The energy demands from the PATHWAYS scenarios were geographically distributed using a tool called Sparse Matrix Operator Kerner Emissions (SMOKE). Then, the air quality impacts of these scenarios were simulated using the Community Multiscale Air Quality Modeling System (CMAQ) tool, accounting for atmospheric chemistry and transport effects to establish distributions of ground-level ozone and $PM_{2.5}$ at a local level. The air quality results were then translated into human health and health benefits metrics using the Environmental Benefits Mapping and Analysis Program (BenMAP) tool. The air quality analysis is discussed in Appendix F.

Building Electrification in California Versus Other Regions

This study finds that electrification in buildings is likely to be the lowest-cost means of dramatically reducing GHG emissions from California's buildings. However, this finding is influenced, in part, by California's relatively mild winter climate.

Electric heat pumps are an efficient means to deliver heating and cooling, but the associated efficiency decreases as the outdoor air temperature drops. Electric resistance heating is commonly used as a supplemental heat source in cold climates, but this use can also lead to substantial new electric-peak demands and the needs for new electric infrastructure in colder climates. Cold climate heat pumps are making important technology strides, but "peak-heat" challenges have been identified as legitimate concerns in colder climates, including parts of northern Europe (Strbac, 2018) and the northern United States (Aas, 2018). Peak heat needs occur during the coldest periods of the year when demand for heating in buildings in highest. These cold periods become particularly challenging when they correspond to periods of low renewable electricity availability. Research in those colder jurisdictions tends to find a plausible ongoing role for low-carbon gas as a "peak-heat" capacity resource.

In studies from colder regions of the world, electrification is also identified as an important strategy to decarbonize buildings, however with a greater reliance on supplemental heat sources. For example, a recent report commissioned by a coalition of European gas utilities finds that widespread electrification of buildings is necessary to achieve the continent's climate goals, and it can be achieved at reasonable cost (Navigant 2019). In that study, gas is used in buildings solely as a capacity resource to avoid large electric sector upgrades. In contrast, in California, with its relatively mild winters and warm summers, electrification of buildings is not expected to cause the state's electricity system to shift from summer peaking to winter peaking (Mahone, 2019). However, more research into local distribution upgrades associated with electrification, as well as changes in electricity demand under future weather conditions influenced by climate change, are both warranted.

This research also did not consider scenarios with greater than 7 percent (by energy) hydrogen blended into the gas pipeline, due to the projected costs of upgrading the gas distribution system and end-use appliances to handle higher blends of hydrogen gas. In European studies, hydrogen in the gas pipeline has been suggested as an option for back-up heating needs in cold climates but, to the author's knowledge, has not been suggested as a cost-effective alternative to building electrification for meeting the majority of annual energy demands in buildings.

CHAPTER 2: Technology Options to Decarbonize the Natural Gas System

Overview

Renewable natural gas (RNG) is an umbrella term that can encompass several low-GHG substitute fuels for fossil natural gas (primarily methane). This report evaluated four categories of RNG: biomethane derived from waste biogas resources via anaerobic digestion, biomethane derived from waste or residues via gasification of biomass (a biofuel production process), hydrogen derived from electrolysis, and synthetic natural gas derived from hydrogen and a renewable CO_2 source (Figure 2). These fuels allow the continued use of natural gas distribution infrastructure, but each has limitations.

Biomethane, purified from biogas sources such as landfills, organic waste digesters, and manure digesters, represents the form of RNG commonly available today, but supplies are limited. Thermochemical processing of agricultural and forest residues and some urban wastes via gasification extends the potential supply of biomethane. However, these residues can also be processed for competing uses, such as liquid biofuels to substitute for petroleum-derived fuels.

Hydrogen can be produced relatively efficiently from zero-carbon electricity via electrolysis, but an upper limit for how much hydrogen can be blended in the existing pipeline system with only modest upgrades is 7 percent by energy (20 percent by volume).[4]

Synthetic natural gas (SNG) also uses electricity as an input and can be directly substituted for fossil natural gas, but it requires a renewable, climate-neutral CO_2 source in addition to hydrogen. Waste bio-CO_2, the waste CO_2 byproduct of ethanol production, is available to produce SNG, however, this low-cost source of climate-neutral CO_2 is relatively limited. Once waste bio-CO_2 sources of CO_2 have been used up, other more expensive sources of climate-neutral CO_2 are needed produce SNG using not-yet commercial technologies such as direct air capture. Collectively, hydrogen and SNG are referred to here as examples of electrolytic fuels, or more specifically as power to gas (P2G) because electricity (power) is used to produce the gas.

For each of these fuel categories, the research team modeled the costs (including costs of energy, capital, and feedstock, where applicable) and the resource potential. The biggest drivers of costs and potential for biomethane are the underlying feedstock supply curves, the conversion efficiencies, and the competing demands for other fuels and sectors. For electrolytic fuels, the costs of input electricity and the assumed effects of innovation on capital costs over time are important drivers.

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4 See Appendix C. Some literature supports a maximum of only 5 percent blending, by energy, without pipeline system upgrades. It was assumed here that up to 7 percent could occur with about $1 per million British thermal units (MMBtu) levelized cost of upgrades, based on Haines et al. (2005). Because 5 to 7 percent represents a small fraction of pipeline throughput, the results are not very sensitive to this assumption.

Figure 2: Four Categories of Renewable Natural Gas That Could Be Used Within Existing Distribution Infrastructure

Waste biogas	Gasification of biomass	Hydrogen	Synthetic Natural Gas
Sources: Municipal waste, manure	**Sources:** Agriculture and forest residues	**Sources:** Electrolysis + zero-carbon electricity, or steam methane reformation with carbon capture and sequestration*	**Sources:** Renewable hydrogen + CO2 from biowaste (bi-product of biofuel production) or direct air capture
Constraints: Very limited supply	**Constraints:** Limited supply and competing uses for biofuels	**Constraints:** Limited pipeline blends (7% by energy, 20% by volume) without costly infrastructure upgrades**	**Constraints:** Limited commercialization, low round-trip efficiency

***This analysis did not model SMR + CCS for hydrogen production.**
****This analysis did not evaluate conversion of the gas system to 100 percent hydrogen, which would require replacement of end-use devices and gas pipeline upgrades.**

Source: E3

Biomethane

Biomethane analysis is integrated with analysis of liquid biofuels, including renewable gasoline, diesel, and jet fuel, and is conducted using the E3 biofuels module described in Mahone et al (2018). This module allows selection of an ideal economywide biofuels portfolio given scenario demands, allocating scarce biomass to competing final fuels. All biofuels are derived from the limited supply of sustainable biomass assumed to be available to California, and most or all of this biomass is used in the mitigation scenarios described in Chapter 3.

Biomass Potential

As in Mahone, 2018, sustainable biomass is defined as consisting of California municipal solid waste (MSW), manure, agricultural residues, and forest residues, in addition to imports of similar feedstocks from other states up to a total equaling California's population share of the United States supply, estimated at 43 million dry tons per year by 2040. Raw biomass supply curves are developed from the United States Department of Energy (DOE, 2016), and these are supplemented by adding resources from Jaffe (2016), which has greater resolution on in-state MSW and manure than DOE (2016). As in E3's prior work, purpose-grown crops and forests primarily for bioenergy production are excluded from all scenarios due to ongoing sustainability concerns, including emissions from indirect land-use change, as well as uncertainty around the plausibility and cost of developing the supply chains necessary to grow, deliver, and process new types of purpose-grown crops for biofuels.[5]

The estimate of 43 million dry tons, including imports of biofuels to California from other states, is comparable to the ranges of California biomass estimates by other studies including the 2017 CEC Integrated Energy Policy Report (IEPR). The author's estimates are higher than all previous assessments of in-state biomass (without including imports), with the exception of the "high biomass scenario" in Youngs and Somerville (2013). These studies are reviewed in Appendix D and include assessments by the California Biomass Collaborative (Williams et al. 2015), reviewed in the 2017 CEC IEPR, as well as more recent assessments by Breunig et al (2018).[6]

Conversion Efficiency and Costs

Anaerobic digestion is a series of biological processes through which microorganisms decompose moist biomass in the absence of oxygen. The products are digestate and biogas, which is typically around 60 percent methane. In order to blend biogas into the gas distribution pipeline, it must be upgraded to remove impurities and increase the share of methane in the gas. Pipeline quality biogas is referred to as biomethane.

Anaerobic digesters are a mature and commercialized technology and are being used at facilities like wastewater treatment plants and agriculture and livestock farms. Because some of the bioenergy content is consumed by microorganisms and left in the digestate, the methane yield is relatively low, for instance, about 38 percent higher heating value (HHV) energy efficiency for dairy manure today. This analysis assumes that industry learning increases the assumed yield over time, reaching 47 percent HHV energy efficiency for dairy manure by 2050. Additional cost is associated with upgrading and injecting the methane into the pipeline. Landfill gas is a special case where the digestion is already inherent to the landfill and most gas is already collected in California, so only the upgrading and injection incur costs.

Gasification reacts fuels with air in a high-temperature, limited oxygen environment to turn dry biomass such as cellulosic or woody feedstocks into syngas, a gaseous mixture composed primarily of hydrogen and carbon monoxide, that is then converted to methane. (Wet feedstocks such as food waste can be gasified as well, with some energy penalty for predrying.) Gasification is a mature technology but not as commercially common as anaerobic digestion for this purpose, and is more expensive, with larger facilities typically required. However, yields are relatively high, and this analysis assumes that they reach 75 percent lower heating value (LHV) energy efficiency for dry woody feedstocks by 2050 compared with 67 percent today. As with anaerobic digestion, upgrading the gas and injection into the gas pipeline also incur costs. Full conversion efficiency and costs for obtaining pipeline-quality biomethane from raw feedstocks are found in Appendix D.

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5 In addition to the references in Mahone, 2018, also note newer work highlighting the concerns about large-scale use of purpose-grown bioenergy resources such as Norton et al. (2019) and IPCC (2019).

6 Breunig et al (2018) estimate up to 71 million dry metric tonnes of gross biomass potential in 2050, but the technical potential of recoverable biomass for fuel was estimated at 40 million dry metric tonnes (44 million dry short tons; obtained via personal communication with H. Breunig in 2018).

Biomethane Potential

With these conversion assumptions and biomass resources, the research team projects the technical potential for biomethane availability for California in 2050, assuming that all available 43 million dry tons of biomass is used exclusively for biomethane. This potential is 635 trillion Btu, which is near the high end of the range estimated in the literature for other studies that estimate the RNG potential for California. A detailed comparison with these studies and explanations for differences is presented in Appendix D.

Biofuel Portfolios

Along with biomethane conversion assumptions, liquid fuel conversion assumptions are used in determining the optimal biofuel portfolios. Commensurate with the cost reductions assumed from industrial production "learning by doing" for biomethane pathways, this analysis incorporated industry learning for advanced liquid fuel pathways that included thermochemical pyrolysis and Fischer Tropsch to convert cellulosic and woody feedstocks to drop-in renewable gasoline, diesel, and jet fuel. Biochemical hydrolysis of cellulosic feedstocks to advanced renewable ethanol was also considered, and conventional corn ethanol was assumed to be phased out consistent with the exclusion of purpose-grown bioenergy resources. Overall, the energy efficiency of thermochemical conversion to liquid fuels reaches about 60 percent by 2050 for conversion of woody feedstock to renewable diesel compared with 54 percent today, somewhat less than assumed for gasification. Complete conversion assumptions are found in Appendix D.

In the PATHWAYS scenarios described in Chapter 3, remaining liquid and gaseous fossil fuel demands are calculated after scenario-driven efficiency and electrification mitigation measures are applied. Given remaining liquid and gaseous fuel demands in those scenarios, and a set of feedstock and conversion cost assumptions, PATHWAYS identifies an optimal biofuels portfolio that maximizes cost-effective CO_2 emissions reduction.

All or nearly all the biomass is used in both mitigation scenarios. In the optimal portfolios, much of the biomass is converted to liquid fuels because of the higher emissions intensity and cost of petroleum fuels compared to natural gas. Some biomethane is also produced for use in CNG trucks, as these attain an assumed market share of at least 24 percent of heavy-duty trucks by 2040, displacing additional petroleum. After accounting for the limited biomethane potential and the competing uses of the feedstock for liquid fuels, biomethane is blended in the range of 15 and 25 percent of natural gas throughput in 2050 in the economywide PATHWAYS scenarios.

As in Mahone, 2018, biofuels costs are based on a single market-clearing price, with economic rents flowing to lower-cost biomass suppliers. Here, the market-clearing price assumes a single implicit carbon price for biofuels across sectors and fuels. Due to the increase in conversion efficiency assumed to occur over time in this study, final biofuels prices are lower than in E3's prior work.

Market-based policies such as the Low Carbon Fuel Standard (LCFS) and cap and trade are not modeled. This analysis uses a societal cost framework that excludes transfers among customers within California. Furthermore, it is unclear what the 2050 carbon prices for LCFS credits or the cap-and-trade market would look like in a future that achieves an 80 percent reduction in GHG emissions economywide.

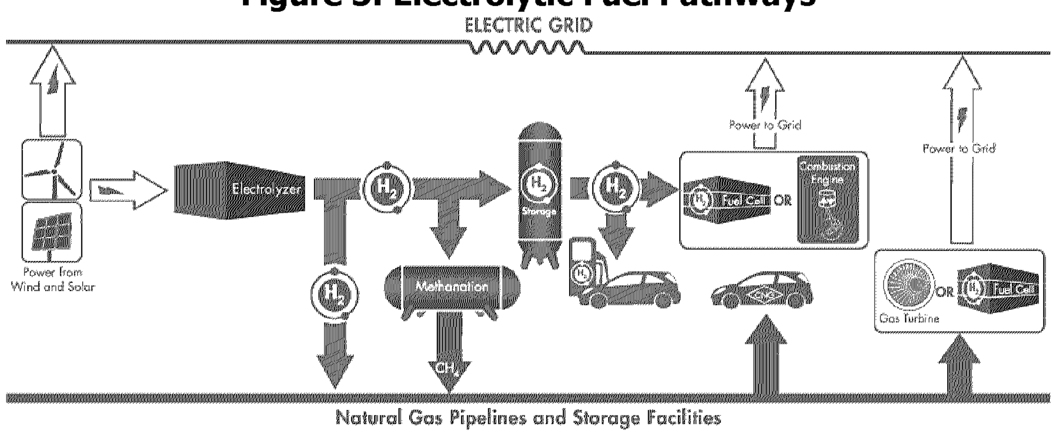
Electrolytic Fuels: Hydrogen and Synthetic Natural Gas

Overview

Power to gas (P2G) is a subset of electrolytic fuels that are considered here as options to be blended into or replace natural gas in the gas transmission, distribution, and storage infrastructure (the "gas system"). P2G consists of transforming electricity to energy in the form of either hydrogen or methane, which can be considered zero-carbon if the electricity source is zero carbon and associated emissions such as fugitive methane or hydrogen are reduced or otherwise accounted for. Because P2G connects the electric grid and the natural gas system (Figure 3), it allows complementary characteristics of these two energy distribution systems to be used, such as the seasonal storage capabilities of the gas system.

Electrolytic fuels have also been modeled, in prior studies, to be a cost-effective use of variable renewables such as wind and solar, which may need to be overbuilt to serve demands at high levels of renewable penetration (Shaffer, Tarroja, & Samuelsen, 2015; Eichman, Mueller, Tarroja, Schell, & Samuelsen, 2013; Baranes, Jacqmin, & Poudou, 2017). However, in the scenarios defined in Chapter 3, the significant quantities of P2G used as a fuel would very likely require additional dedicated renewable capacity to produce the fuel, far more renewables than would be available as oversupply of renewable generation that was developed to satisfy other electricity demands. This requirement is because the energy demands associated with producing hydrogen and synthetic natural gas at the scales envisioned in deep decarbonization scenarios far exceed the amount of electric curtailment that would occur in an electric system that balances curtailment, storage deployment, and use of firm generating resources for reliability (Chapter 3).

Figure 3: Electrolytic Fuel Pathways



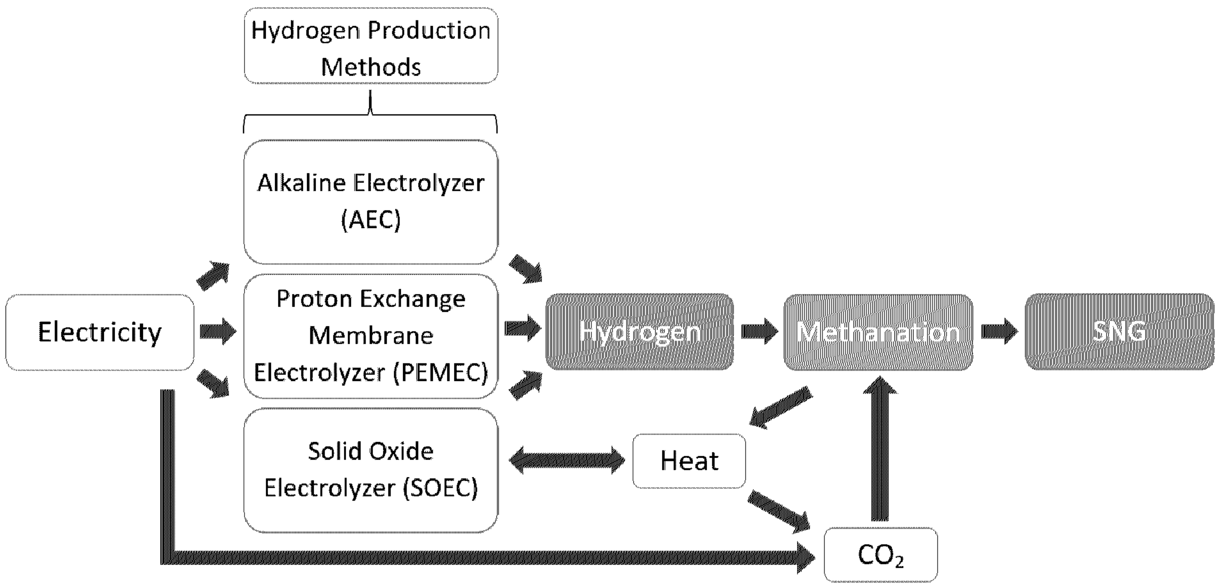
This is an illustrative schematic; not all pathways shown here are considered in this study. The hydrogen- and CNG-fueled cars represent broader use in the transportation sector including in trucks.

Source: UCI APEP

An assortment of P2G technologies are being considered in the academic literature as well as in small commercial pilots, and these are reviewed in more detail in Appendix C. The research team selected technologies based on the related environmental characteristics and a technology readiness level (TRL) of 6 or higher.[7] Only pathways that could be considered zero carbon in a decarbonized energy system were included. For instance, sourcing CO_2 from post-fossil-fuel-combustion capture was excluded, and this analysis did not assume that excess zero-carbon waste heat from industry or combined heat and power (CHP) would be available as an input (Figure 4).

Two key technology choices are the type of electrolyzer and the CO_2 source; other technology considerations are discussed in Appendix C. Electrolyzer technologies included in this study are alkaline electrolytic cells (AECs), proton exchange membrane electrolytic cells (PEMECs), and solid oxide electrolytic cells (SOECs). AECs and PEMECs are common today, while SOECs have the highest efficiency and the greatest potential for price reduction with increased scale, even though they are more expensive today.

Figure 4: Flowchart of Analyzed Power to Gas Pathways



Source:

Source: UCI APEP

The CO_2 source technologies considered include post-combustion capture (PCC), direct air capture (DAC), and electrolytic cation exchange modules (E-CEM). PCC is considered only in the case of co-locating P2G plants with a biorefinery to source carbon dioxide from them. Biorefineries such as those producing biofuels from anaerobic digestion, pyrolysis, hydrolysis, and gasification have streams with relatively high concentrations of CO_2 (Jones et al., 2013; Kabir Kazi, Fortman, & Anex, 2010; Humbird et al., 2011; Davis et al., 2014; N. C. Parker,

7 The *technology readiness level* is a metric used by the United States Department of Energy (U.S. DOE, 2011) and other sources to assess the maturity of technologies and readiness for commercial-scale deployment. It ranges from 1 for basic research to 9 for fully mature: operation of the actual system over the full range of operating conditions.

Ogden, & Fan, 2008; Liu, Norbeck, Raju, Kim, & Park, 2016), which can be separated from the streams relatively efficiently.[8]

DAC involves a liquid solvent or solid sorbent to capture CO_2 from the ambient air. These approaches are being tested in pilots by Carbon Engineering (based in North America) and Climeworks (based in Switzerland), respectively. Because of the lower concentration in ambient air, DAC is more expensive and is highly energy-intensive. A recent review (NAS, 2018) found it required 0.15 to 0.47 megawatt-hour (MWh) electricity input and 3.2 to 10.1 MMBtu of heat input per tonne of CO_2 captured, which is assumed here to be provided by electric resistance heating.[9]

The United States Navy is pursuing E-CEM technology, which is promising due to the ability of the technology to capture carbon dioxide and hydrogen from seawater (Parry, 2016). However, it has a lower TRL than DAC and is projected to be higher cost, so it is not included in the PATHWAYS scenarios in Chapter 3.

Projections of Efficiency and Cost for P2G Pathways

For hydrogen and SNG, the research team determined the efficiency and cost metrics over time as a function of five major inputs. The resulting efficiency and cost metrics included the levelized per-unit capital costs, variable operations and maintenance (VOM) costs, and the overall energy efficiency in units of MMBtu of fuel produced per MMBtu of electricity input.

1. Industry learning rate and global installed capacity: The industry learning rate is used along with Wright's Law (Nagy, Farmer, Bui, & Trancik, 2012) to project future cost declines as cumulative global installed production capacity increases. Higher learning rates and greater global industry scale-up lead to greater cost decreases.
2. Electrolysis technology: This technology is discussed above.
3. CO2 source (for SNG): CO2 is a waste product of biofuel production and may be used as a climate-neutral CO2 source for SNG production. This product is referred to as a biorefining CO2 coproduct and is used to produce SNG when possible, as a cost saving measure. However, the availability of this biorefining CO2 coproduct depends on SNG production colocated with biorefining, which is assumed to be limited in each scenario. After this supply is exhausted, DAC is used as the CO2 source for SNG production.
4. Energy supply: This analysis assumes the energy is provided by utility-scale solar PV or wind generation, harmonized with the PATHWAYS scenario cost assumptions. The electricity could be provided on-grid. If operated flexibly, hydrogen and SNG production could help to integrate renewable generation on the grid, for example, by turning on during periods of renewable overgeneration, and turning off during peak demand

8 Technically, no combustion need occur in some of these biorefining processes, but this study uses the term "post-combustion capture" to be consistent with the commonly used term in the literature.

9 A tonne is a metric ton. Metric units are used throughout this report. As discussed, large quantities of waste heat input may not be available in a low-carbon future. The temperature required varies depending on the DAC process, ranging from 100 to 900 ° Celsius. Other sources for this waste heat, not evaluated here, include natural gas with CCS, collocating electrolytic fuel production with nuclear power, additional biomass, concentrating solar thermal, or a heat pump at the lowest end of the temperature range.

periods. Off-grid fuel production avoids new transmission costs. The research team determined the latter option was more cost-effective in the scenarios modeled here. In particular, researchers assumed enough flexibility in other loads that the renewable integration benefits of on-grid fuel production were outweighed by the cost of new transmission.

5. Capacity (that is, load) factor: The capacity factor is implied by the source of energy supply. Greater capacity factors mean better capital utilization for P2G equipment and, thus, lower levelized capital costs; however, especially if the energy input is restricted to be zero-carbon, this improved utilization may mean higher energy costs. In these scenarios, researchers did not consider baseload zero-carbon feedstocks like nuclear power or fossil fuel with CCS, so the capacity factor is aligned with the renewable generation resources determined to be used.10

For many of these inputs, the research team developed assumptions for conservative and optimistic P2G cost scenarios. These assumptions are summarized in Table 1, with full details in Appendix C. The conservative cost scenario aligns more closely with the costing approach used elsewhere in the PATHWAYS modeling (Chapter 3).

Table 1: Summary of Power to Gas Assumptions

Assumption	Conservative Scenario	Optimistic Scenario
Industry Learning	Moderate learning and scale-up*	Rapid learning and scale-up*
Electrolysis Technology	Even proportions of AEC and PEM through 2030, transitioning to SOEC by 2040	Even proportions of AEC and PEM in 2020, transitioning to SOEC by 2030
CO_2 Source	Limited California bio-CO_2 coproduct, with most provided by DAC	Entirely bio-CO_2 coproduct from co-located Midwest biofuel production[11]
Energy Source	Off-grid California solar ($26/MWh and 25% cap factor in 2050)	Off-grid Midwest wind ($40/MWh and 40% cap factor in 2050)

***Moderate scale-up implied 0.3 terawatt (TW, a trillion watts) of global electrolysis capacity by 2050, while rapid scale-up implied 2.7 TW. (Today's capacity is estimated at 0.013 TW). See Appendix C for full details.**

Source: E3

In these two scenarios, this analysis projects the efficiency of hydrogen electrolysis with SOECs to reach 80 percent by 2050. The overall energy efficiency of SNG production is lower,

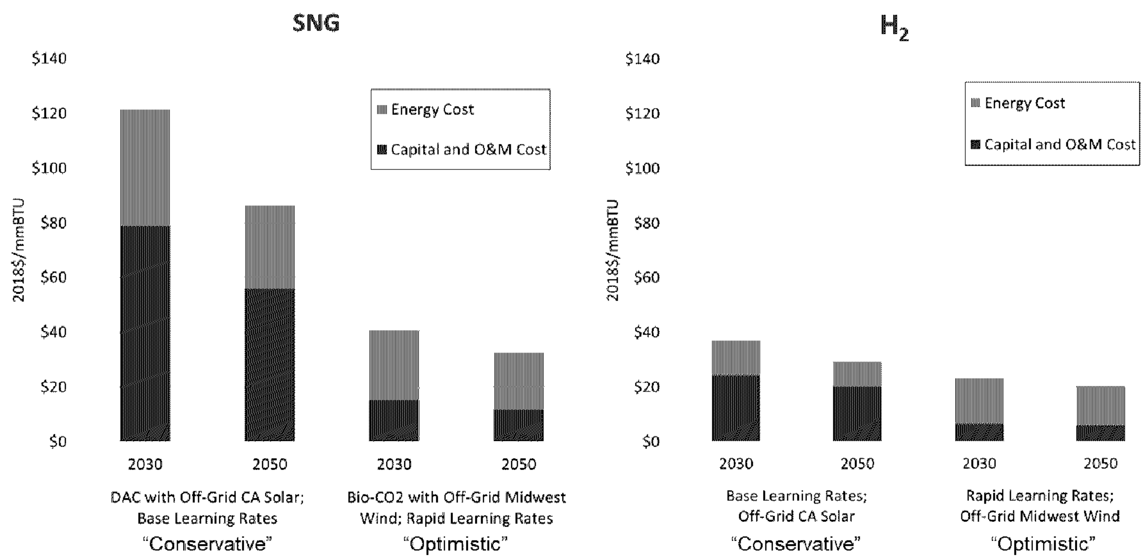
10 Higher capacity factor could be assumed if additional renewable integration solutions, such as batteries, were used to maximize P2G capital utilization, with uncertain impacts on total cost. This option was not evaluated here.

11 This requires coordination of biofuel production with SNG production outside California, the colocation of this production with off-grid wind farms, and California GHG credit for injection of this SNG into the gas pipeline system at the point of production.

as methanation and CO_2 supply are associated with additional conversion losses. The efficiency reaches 56 percent with bio-CO_2 and 45 percent with DAC in 2050.

The resulting all-in commodity costs are illustrated in Figure 5. The costs of SNG are very high when DAC is required. Even with modest cost declines due to industry learning, SNG produced from a new plant is projected to be \$86/MMBtu by 2050 in the conservative P2G scenario, compared with a natural gas price forecast of \$5/MMBtu. Commensurate with the optimistic case with full use of bio-CO_2 and rapid industry learning, costs from a new plant decline to just greater than \$30/MMBtu in 2050, consistent with other studies (Navigant 2019). Commodity costs of hydrogen are projected to be much lower than those of SNG, reaching as low as \$20/MMBtu for a new plant in 2050 in the low-cost scenario; however, the upper limit of 7 percent in the existing distribution pipeline system limits the benefit of this lower-cost P2G option.

Figure 5: Power to Gas Commodity Costs for Production From a New Plant in 2030 or 2050



These are costs for production from a new plant in 2030 or 2050 with either 100 percent DAC or 100 percent bio-CO_2 and a single electrolysis technology. The conservative and optimistic labels roughly correspond with the PATHWAYS scenarios shown in Chapter 3. In PATHWAYS, however, the capital costs are vintage over an assumed 20-year life, the CO_2 source blend varies over time in the base cost scenario, and the electrolysis technology blend also varies over time.

Source: E3

Renewable Natural Gas Supply Curve

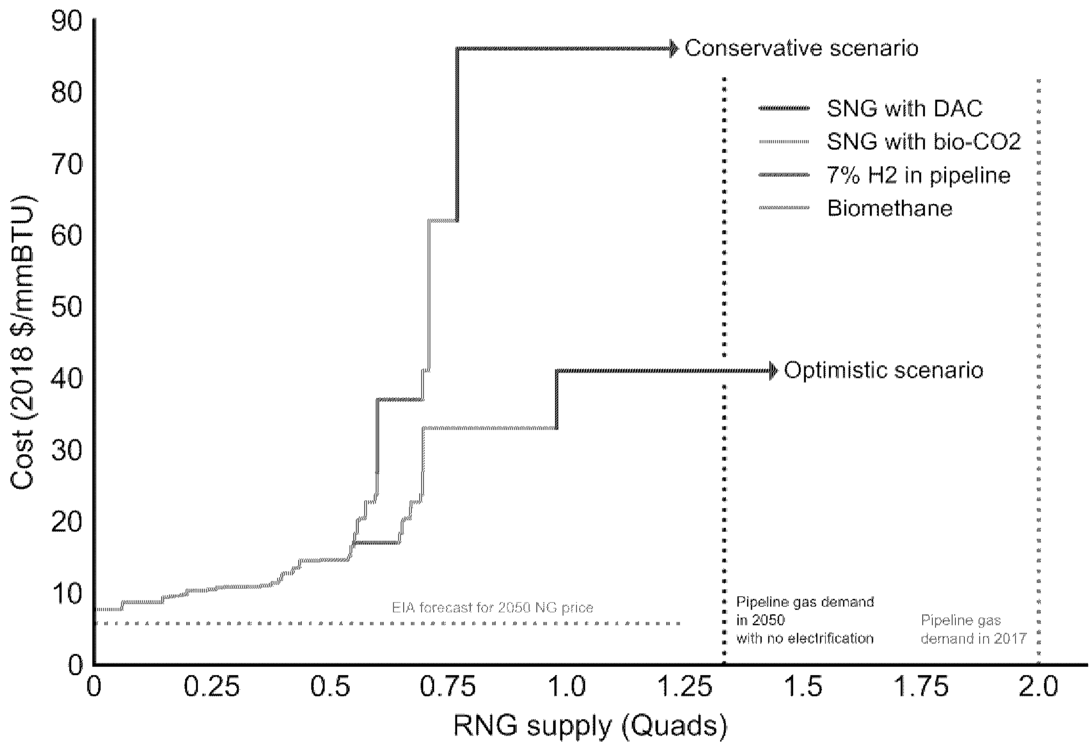
Figure 6 below summarizes the results of this section in a supply curve representing the technical potential for RNG available to California using the four categories of RNG assessed: biomethane from waste biogas via anaerobic digestion; biomethane from gasification of wastes and residues; electrolytic hydrogen up to a 7 percent pipeline blend; and electrolytic SNG, with a portion, representing the available bio-CO_2 followed by SNG with DAC as the marginal, potential-unlimited resource.

As was found in Mahone et al (2018), Figure 6 implies that there is insufficient low-cost, sustainable RNG supply to decarbonize the pipeline fully without electrification. Pipeline gas demand in 2017 was 2 quadrillion Btu (quads), including electricity generation. This demand could decline to 1.3 quads in a scenario with high energy efficiency and renewable electricity generation by 2050 (Chapter 3). However, the relatively low-cost RNG (from California's population share of United States biomass, excluding purpose-grown crops), provides only a maximum of 0.6 quads in the absence of any competing demands for this resource. Consequently, expensive portions of the RNG supply curve available would very likely be needed to decarbonize gas demand without electrification.

In the optimistic scenario, SNG with DAC at $41/MMBtu would be the marginal resource required to fully decarbonize the gas system in 2050.

With economywide decarbonization (Chapter 3), competing uses for the limited biomass resource available further reduce the economic potential of RNG. Much of the biomass may be used to displace relatively expensive and high-GHG-intensity petroleum fuels, such as diesel and jet fuel. Indeed, current state policy directs nearly all biofuel production toward transportation, most of this as liquid biofuels.

Figure 6: California Renewable Natural Gas Technical Potential Supply Curve in 2050, Assuming All Biomass Is Directed to Renewable Natural Gas



The biomethane supply curve segments (green) are based on allocating California's population-weighted share of United States waste and residue biomass entirely to biomethane. In the PATHWAYS scenarios, much of the biomass is used for liquid fuels to displace petroleum consumption in transportation and industry.

Source: E3

CHAPTER 3: California Economywide Decarbonization Scenarios

Methods

PATHWAYS Model

The California PATHWAYS model uses user-defined scenarios to test how mitigation measures interact across sectors and add up to meet deep economywide emissions targets. The California PATHWAYS model has been used in several California studies, including research that informed setting the state's 2030 GHG goal (E3, 2015), studies to model the California Air Resources Board (CARB) Scoping Plan Update (CARB, 2017), and CEC research exploring a range of scenarios to achieve an 80 x 50 goal for 2050 (Mahone et al, 2018). Because the model represents the stocks and turnover of building appliances and on-road vehicles, it represents the infrastructure inertia of the energy system. Modeling a deep decarbonization scenario requires making tradeoffs about how to allocate scarce fossil and bioenergy budgets across sectors to meet an economywide GHG constraint. For example, different scenarios may leave more fossil emissions in the transportation sector versus the industrial or buildings sector.

The model used in this study includes minor updates to that used in Mahone et al (2018) beyond the improved representation of RNG and biofuels discussed in Chapter 2 and described in Appendix E. Costs of renewable electricity generation and battery storage resources have been updated, resulting in lower cost renewable electricity post-2030.

In addition, retrofit costs for installing heat pumps in existing buildings were added, with a range of $0 to $8,000 of incremental capital cost assumed upon first fuel-switching to heat pump space heating for homes, depending on vintage and the presence of existing air conditioning (AC).[12] Retrofit costs were added in commercial buildings upon first fuel-switching, with a range of 0% to 100% of the capital cost of heat pump HVAC. Together, these retrofit costs add nearly $3 billion of annualized capital costs to high electrification scenarios in 2050 based on building retrofits over the preceding decades. This cost increment peaks in 2048 and would decline over time if the scenario were continued beyond 2050, as a smaller share of buildings incur retrofit costs over time. While incremental building electrification retrofit costs are uncertain, they were not found to significantly impact the study results.

12 See (Mahone et al., 2019) for a more detailed analysis of costs to retrofit existing buildings for electric appliances. The range here is based loosely on TRC (2016) and accounts for electrical panel upgrade costs, as well as first-time costs in the absence of existing air conditioning like compressor siting. See Appendix E for more details.

Scenario Design

In (Mahone et al., 2018), researchers developed 10 scenarios that met the climate goal of 80 percent GHG reductions below 1990 levels by 2050 ("80 x 50"). These scenarios tested the impact of greater or lesser reliance on key decarbonization strategies, like building electrification, biofuels, and hydrogen trucks. That study found that building electrification resulted in substantially lower economywide mitigation costs, relative to a scenario that excluded building electrification but had comparable other assumptions, such as biofuel availability.

In this study, the research team adapts several of the scenarios presented in 2018 to incorporate the biofuels and P2G analysis in Chapter 2, as well as other minor updates to cost and scenario assumptions. These scenarios (Table 2) were designed to investigate whether updated RNG cost information changes any of the previous findings, as well as to explore the distributional and air quality impacts of building decarbonization strategies (subsequent chapters). This report highlights two bookend scenarios, a "high building electrification" scenario (HBE) and a "no building electrification" scenario (NBE). Those scenarios are compared against a common baseline, the "current policy reference scenario" (shortened to Reference). Full scenario assumptions, such as key input measures by sector, are in Appendix E. Several additional scenarios were developed with intermediate levels of building electrification, but these were found to show predictable intermediate results on key scenario metrics, so they are included only in the appendix.

- Current Policy Reference: This scenario does not meet California's 2030 and 2050 GHG goals. It reflects the energy efficiency goals of Senate Bill (SB) 350, the CARB Short-Lived Climate Pollutant Strategy (SLCP—De León, Chapter 547, Statutes of 2015), the CARB Mobile Source Strategy, and other known policy commitments included in the 2017 Scoping Plan Update (CARB, 2017),[13] as well as a "zero-carbon retail sales" interpretation of SB 100.[14] Besides SB 100, additional updates since the 2018 published "Current Policy Scenario," based on recent trends and legal challenges, include assuming reduced progress in fuel economy standards of new vehicles and higher vehicle miles traveled (VMT). Only very high efficiency natural gas furnaces and water heaters are installed by 2025, and no building electrification is assumed.
- High Building Electrification: This scenario (based on the 2018 "no hydrogen" scenario) achieves a 40 percent reduction of GHGs below 1990 levels by 2030 and 80 percent by 2050. It includes high electrification of buildings. The scenario also includes high electrification of light-duty vehicles and moderate electrification of medium- and heavy-duty vehicles, with fuel-switching of most non-electrified diesel trucks to compressed natural gas (CNG) for air quality. The limited biofuel and fossil energy emissions

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13 As in previous PATHWAYS studies, the CARB Cap-and-Trade Program is not explicitly modeled, but it would be expected to contribute to further emission reductions beyond those associated with these known policy commitments.

14 Interpretation of SB 100, a 2018 law to decarbonize electricity, is still ongoing. This study assumes that it requires utilities to procure zero-carbon generation equal to their retail sales by 2045, with a small amount of remaining in-state or imported natural gas generation commensurate with losses, exports, and other exemptions. In 2030, SB 100 is represented as a 60 percent RPS.

budgets are allocated largely to transportation (particularly heavy-duty and off-road) and industry, including pipeline biomethane. Buildings are nearly completely decarbonized by 2050. Most but not all the available biomass is used for advanced biofuels, as the maximum portfolio is not needed to meet the economywide GHG target.

Table 2: PATHWAYS Scenario Summary of Key Metrics for 2050

Category	Reference	High Building Electrification	No Building Electrification
GHG Emissions	Does not meet state climate goals	Meets 40 x 30 and 80 x 50 goals	Meets 40 x 30 and 80 x 50 goals
Building Electrification	None	100% equipment sales by 2040	None
Industrial Electrification	None	None	None
Pipeline Biomethane (% energy)	0%	25%	16%
Pipeline H_2 (% energy)	0%	0%	7%
Pipeline SNG (% energy)	0%	0%	21%
Electric and Fuel Cell Trucks	Low	Medium	High
Advanced Biofuels	71 TBTU	478 TBTU	533 TBTU
Energy Efficiency	Meets SB 350	Exceeds SB 350	Exceeds SB 350
Light-Duty Vehicle Electrification	Medium	High: 100% Sales by 2035	High: 100% Sales by 2035
Short-Lived Climate Pollutants	Meets CARB SLCP Strategy	Exceeds CARB SLCP Strategy	Exceeds CARB SLCP Strategy
CNG Trucks	Displace some diesel trucks	Displace most non-electrified diesel trucks	Displace most non-electrified diesel trucks
% Zero-Carbon Generation	89%	95%	95%

Notes: The "40 x 30" goal is a 40% reduction of GHG emissions below 1990 levels by 2030, and the "80 x 50" goal is an 80% reduction of GHG emissions below 1990 levels by 2050. Although the blend proportion of biomethane is smaller in the no building electrification scenario, the total quantity is similar due to the greater pipeline throughput. Advanced biofuels exclude corn ethanol. SB 100 compliance is based on a zero-carbon retail sales interpretation, meaning that less than 100% of total generation is served by zero-carbon resources. The reference and no building electrification scenarios do not include any fuel substitution of natural gas end uses in buildings for electricity, instead maintaining a constant market share of natural gas end uses; however, some propane and fuel oil end uses are electrified. A more detailed listing of scenario measures is in Appendix E.

Source: E3

- No Building Electrification: In this scenario, fuel-switching in buildings is not assumed. Natural gas and electric appliance shares remain constant from 2015. This scenario represents a hypothetical bookend, as some economic or local policy-driven electrification is underway. Only high-efficiency natural gas furnaces and water heaters are installed by 2025. The same high level of light-duty vehicle electrification is assumed as in high building electrification, and most non-electrified diesel trucks shift to CNG. To make up for the emissions mitigation shortfall from not electrifying buildings, hydrogen and SNG are blended into the pipeline as well as biomethane; in addition, more battery-electric and hydrogen fuel cell trucks are included. Much of the limited biofuel and fossil energy emissions budgets are allocated to buildings. The pipeline gas blend remains 56 percent fossil natural gas by 2050 to avoid increasing scenario costs by blending additional expensive SNG. In addition to a similar amount of biomethane and renewable diesel as in the high building electrification scenario, the remainder of the biomass supply is used to make renewable gasoline and jet fuel to displace additional GHGs. For cost results, this analysis presents both using the conservative and optimistic P2G cost scenarios (Chapter 2).

Greenhouse Gas Accounting and Methane Leaks

PATHWAYS uses a direct GHG emissions accounting metric benchmarked to the CARB inventory for 2015 emissions. The CARB inventory is used to monitor California's progress against its emissions reduction targets. This inventory accounts for in-state emissions as well as emissions from imported electricity. It uses the 100-year global warming potentials (GWP) calculated based on the 2007 IPCC (the fourth assessment report) (Forster et al., 2007).[15] Because the inventory focuses on in-state emissions, upstream or life-cycle emissions from imported fossil fuels and biofuels are excluded,[16] as are embedded emissions from imported goods and raw materials. The 20-year GWP is sometimes used to emphasize the role of short-lived climate pollutants (SLCPs), such as methane, black carbon or fluorinated gases, which have a shorter residence period in the atmosphere than carbon dioxide in near-term warming. However, the research team cautions that neither GWP metric is universally appropriate.

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15 The United States EPA explains 100-year global warming potential in the following way, "The Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO2). The larger the GWP, the more that a given gas warms the Earth compared to CO2 over that time period. The time period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases." Quoted from United States Environmental Protection Agency (https://www.epa.gov/ghgemissions/understanding-global-warming-potentials).

16 To avoid GHG emissions from indirect land-use change, additional fertilizer use, and so forth, biofuels are limited to those derived from waste and residue resource (Chapter 2). Depending on the future biofuels industry development, fossil emissions associated with collecting, transporting, and processing the biomass may occur. Fossil natural gas extraction incurs significant upstream emissions from fugitive methane, but petroleum extraction and transport are also associated with large upstream emissions, varying widely depending on the petroleum source.

The CARB inventory includes fugitive methane emissions from in-state natural gas production and the pipeline system. The most recent inventory update (2019) also includes behind-the-meter methane leakage from homes, which is equivalent to roughly 0.5 percent of residential consumption, based on CEC research (Fischer et al., 2017). That increase represents a 4 percent increase in CO_2-equivalent (CO_2e) emissions associated with residential natural gas consumption, using the 100-year GWP (0.9 MMT CO_2e). The total fugitive methane emissions in the CARB inventory are equivalent to about 0.7 percent of statewide natural gas consumption. Recent studies support higher leakage proportions in the Greater Los Angeles Area and eastern United States metropolitan areas (He et al., 2019; Plant et al., 2015), but it is not yet clear whether these would generalize to all of California or the United States, respectively.

This study includes only fugitive emissions quantified in the 2015 CARB inventory and assumes that methane leak mitigation will proceed according to the CARB SLCP Strategy in all scenarios, achieving a 40 percent reduction by 2030. As a simplifying assumption and because of the absence of available data,[17] this analysis does not assume that reduction in gas consumption avoids any fugitive emissions, nor does it assume any increased fugitive emissions from gasification or SNG production. These assumptions collectively could lead to underestimating the magnitude of GHG emissions from continued use of methane in buildings. In particular, higher levels of behind-the-meter methane leakage would suggest that electrification of buildings could reduce more GHGs than estimated in this study.

Cost Accounting and Scenario Philosophy

PATHWAYS scenario economywide costs are based on a total resource cost (TRC) metric. This metric includes all direct energy system costs within the California economy resulting from fuel consumption and from capital costs from energy infrastructure associated with purchase of building appliances or vehicles, as well as incremental energy efficiency or fuel-switching capital costs. It does not represent transfers within the California economy such as Low Carbon Fuel Standard (LCFS) credits, the Cap-and-Trade Program, or other new policy incentives; distributional impacts will be discussed in Chapter 4 and Chapter 5. The metric also excludes societal costs from air pollution, both from local health impacts and GHG emissions. For a quantification of air quality benefits from electrification see the air quality results section of this report and Appendix F.

Technology costs for climate mitigation measures in PATHWAYS are generally conservative, representing expected, incremental innovation relative to commercially available technologies. No major cost reductions or market transformation are assumed *except* for biofuels and electrolytic fuels (Chapter 2). For instance, modeled heat pump space heater efficiencies in PATHWAYS improve only modestly from an achieved coefficient of performance (COP) of 3.2

17 It is unclear how much methane leakage could be avoided in a scenario with reduced throughput or partial shutdown of gas distribution infrastructure but without complete shutdown. Likewise, E3 is not aware of estimates of methane leakage associated with gasification and SNG production. Elimination of most natural gas appliances in buildings would save up to 0.9 MMT CO2e from behind-the-meter leakage not accounted for here.

to 4.3 for new installations between 2015 and 2030. No improvements are assumed between 2030 and 2050.[18]

This report focused on the potential innovation in RNG technologies specifically to test whether these would change the results from E3's 2018 Deep Decarbonization study, which showed that building electrification was a more cost-effective option to decarbonize buildings. In addition, this analysis does not assume any increase in air conditioning adoption relative to the adoption share found in existing buildings, even though recent trends that could be enhanced by climate change show greater levels of AC adoption.[19] This assumption is a modeling limitation that the research team intends to address in future studies. Previous work (Mahone et al, 2019) finds that heat pump space heaters have zero or negative incremental capital cost when central AC is present or planned. If there were more AC in the current policy reference scenario, the incremental cost of the high building electrification scenario would be lower than that calculated here.

Scenario Results

Energy Consumption

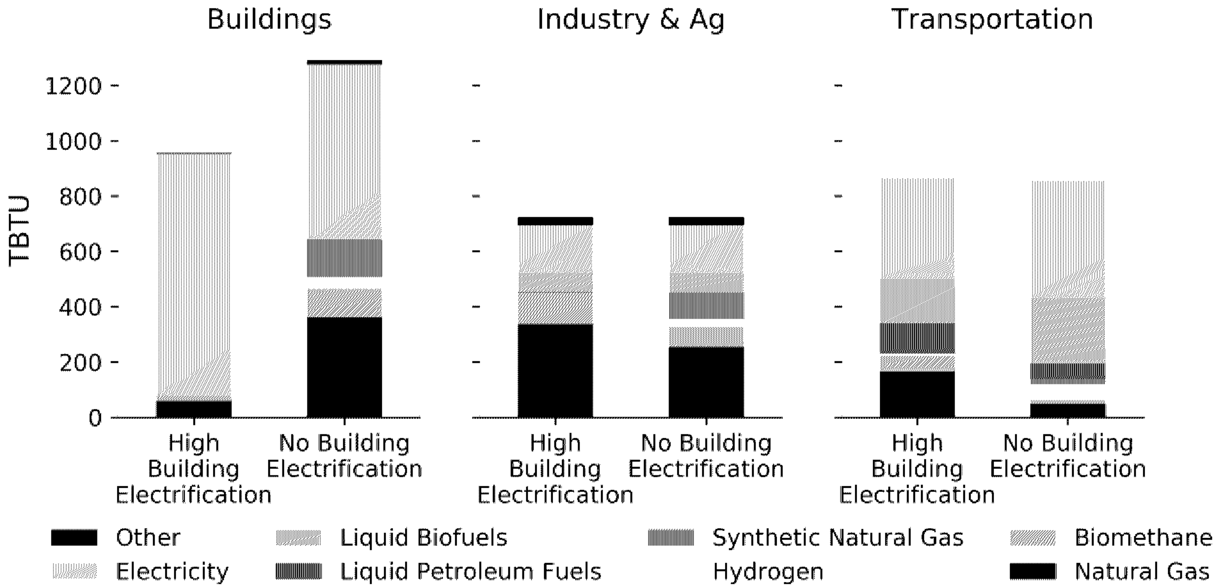
Both mitigation scenarios show a large increase in electricity demand and decrease in fossil energy demand relative to today's fuels, with especially large reductions in transportation fossil energy demand (Figure 7 and Figure 8). However, several differences between the high building electrification and the no building electrification scenarios emerge. The high building electrification scenario has lower energy demand overall because of the efficiency associated with building electrification. Both scenarios include substantial quantities of remaining fossil natural gas and relatively similar quantities of biofuels by 2050, but these are allocated to different sectors. The high building electrification scenario allocates more natural gas and biomethane to transportation, industry, and agriculture, while in the no building electrification scenario, about half of these fuels are consumed in buildings.[20] The no building electrification scenario also includes 53 trillion British thermal units (TBtu) of liquid hydrogen for trucks and 82 TBtu of hydrogen in the pipeline, plus 248 TBtu of SNG. Hydrogen, which is the less expensive electrolytic fuel, remains a small proportion of economywide fuel consumption in the no building electrification scenario because of the 7 percent pipeline blending limit and a substantial reliance on battery-electric trucks rather than hydrogen fuel cell trucks.

18 The *COP* is a measurement of the efficiency of the equipment. In California, where temperatures are relatively mild compared to other parts of the country, the achieved efficiency of heat pumps can exceed the rated efficiency. The COP assumptions applied in this study are conservative, as the COP of 3.2 is close to the code minimum requirement, and most models on the market would exceed it if properly installed.

19 The Residential Appliance Saturation Survey shows a trend of increasing central air-conditioning penetration in newer building vintages.

20 Both scenarios also allocate biomethane to electricity generation based on the pipeline blend assigned to other sectors. In the current PATHWAYS implementation, hydrogen and SNG are not allocated to electricity generation and are instead assumed to be used by other sectors (such as transportation, buildings, and industry).

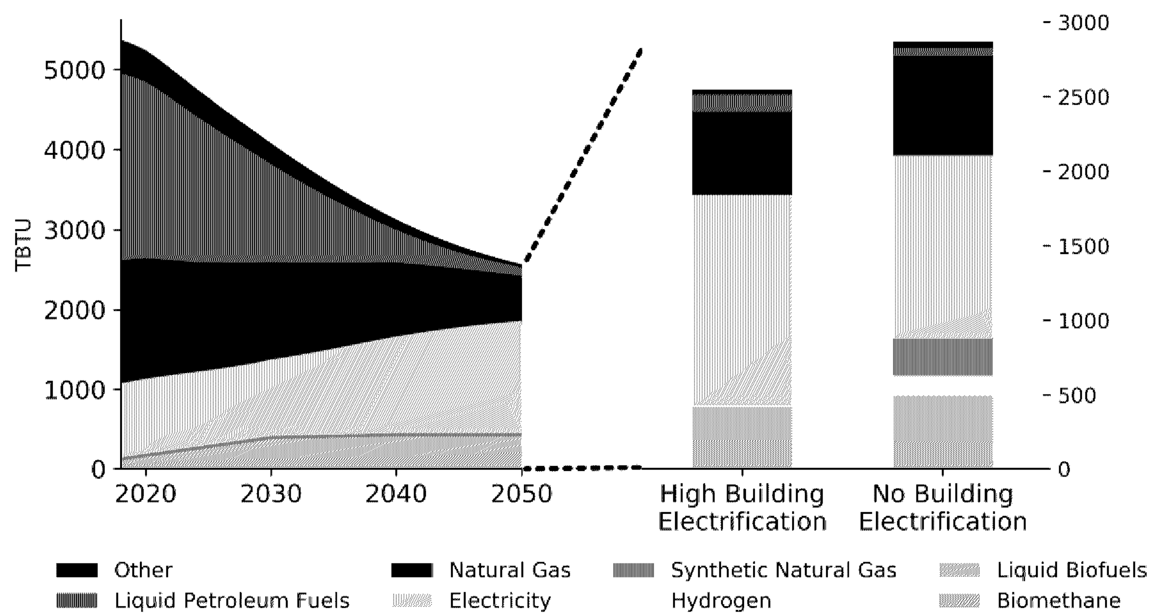
Figure 7: Final Fuel Consumption by Sector in PATHWAYS Scenarios in 2050



Final fuel consumption is final energy demand broken out by fuel constituent (that is, fossil fuel, biofuel, or electrolytic fuel). "Other" fuels include solid fossil fuels, wood, refinery gas, liquefied petroleum gas (that is, propane), and waste heat.

Source: E3

Figure 8: Economywide Final Fuel Consumption in PATHWAYS Scenarios

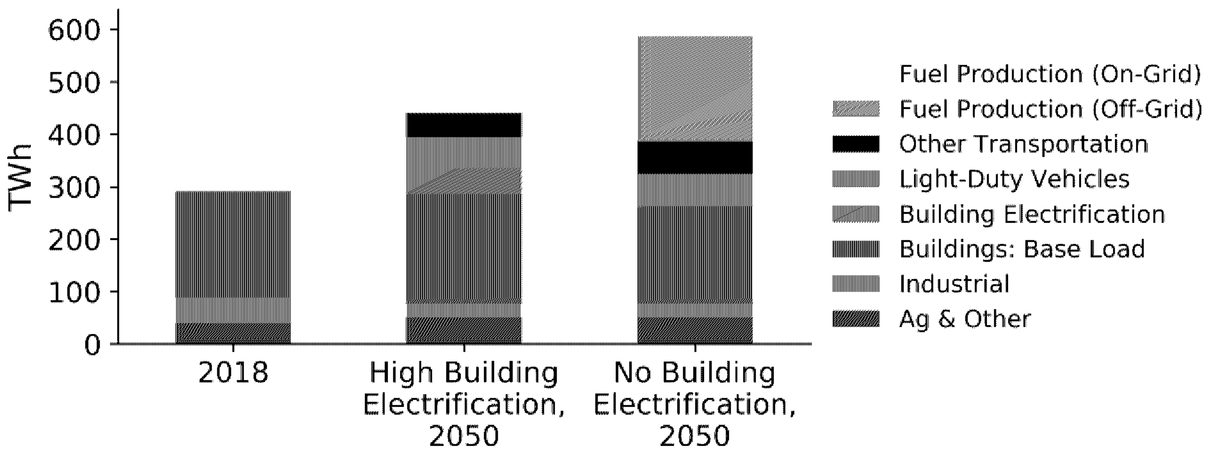


Final fuel consumption is final energy demand broken out by fuel constituent (in other words, fossil fuel, biofuel, or electrolytic fuel). "Other" fuels include solid fossil fuels, wood, refinery gas, liquefied petroleum gas (that is, propane), and waste heat. The bar charts on the right are for 2050.

Source: E3

Both scenarios show large increases in electricity loads relative to today's loads, but loads are greater in the no building electrification scenario, when the fuel production loads are accounted for. Fuel production loads total 195 to 222 TWh in 2050, depending on the P2G cost scenario, compared with today's loads of about 293 TWh. Most of these fuel production loads are assumed to be served by off-grid wind and solar, so they may avoid buildout of new transmission and distribution infrastructure. Off-grid renewables are cheaper than on-grid renewables once accounting for the fact that renewable curtailment or "over-generation" of renewables will not lead to zero, or negative, cost electricity for any significant quantity of hydrogen production. New nuclear or CCS technologies are not considered as a fuel production pathway in this study. In these scenarios, fuel production still represents a larger expansion of the electricity system and renewable generation capacity requirement than in the high building electrification scenario. In the high building electrification scenario, nearly complete electrification of buildings induces 47 terawatt-hours (TWh) of new load, which is less than half that associated with transportation electrification.

Figure 9: Electricity Loads by Sector in PATHWAYS Scenarios



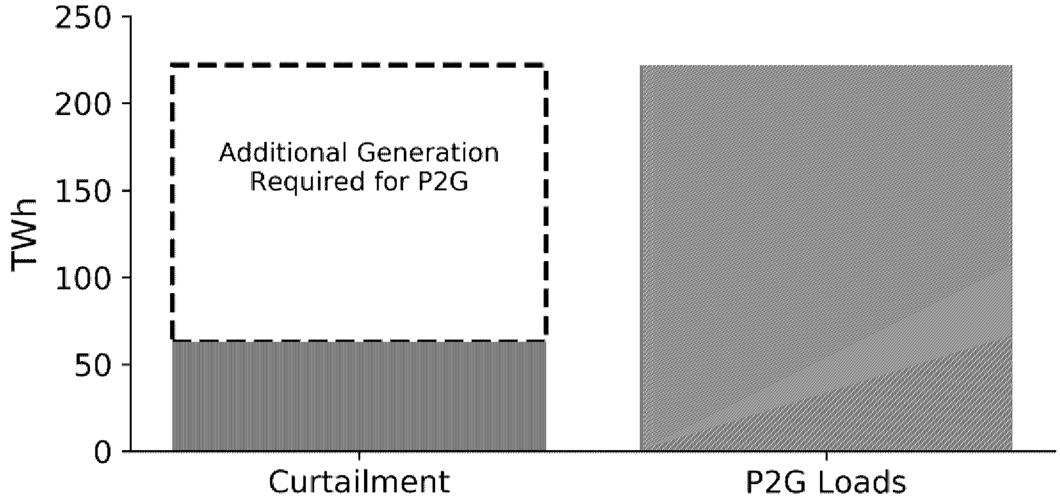
Electricity loads consist of final demand for electricity, except for fuel production loads; production of hydrogen and SNG are assumed served by off-grid renewables, except for liquid hydrogen for delivery to fuel cell trucks, which are assumed to be produced on-grid so they can be relatively close to consumption. The no building electrification scenario loads shown here correspond to the conservative cost P2G scenario. These loads would be slightly lower in the optimistic cost P2G scenario due to greater use of bio-CO_2 rather than DAC.

Source: E3

A common claim is that electrolytic fuel production can use low-cost wind and solar energy that would otherwise be curtailed. This study finds that the loads required to produce sufficient quantities of hydrogen and SNG far exceed the amount of curtailment that can be expected in a future electricity system that uses renewable integration solutions. Those solutions include flexible loads, storage, and gas combustion turbine electric generators that use a small amount of biomethane or natural gas. Using those solutions, 16 percent of renewable generation, or 63 TWh, is curtailed in the no building electrification scenario.[21] This curtailment means that up to 159 TWh of additional electricity generation is needed for fuel-production alone in this scenario, or just greater than half of California's annual electric loads today (Figure 10).

21 This amount is based on PATHWAYS modeling, which does not optimize the portfolio of renewables and storage to strictly minimize electricity generation costs. RESOLVE modeling for an 80 x 50 scenario in (Mahone 2018) showed 15 percent curtailment. Newer simulations with lower-cost storage yield lower optimal curtailment levels.

Figure 10: 2050 Curtailment Compared to Power to Gas Loads in the No Building Electrification Scenario



Source: E3

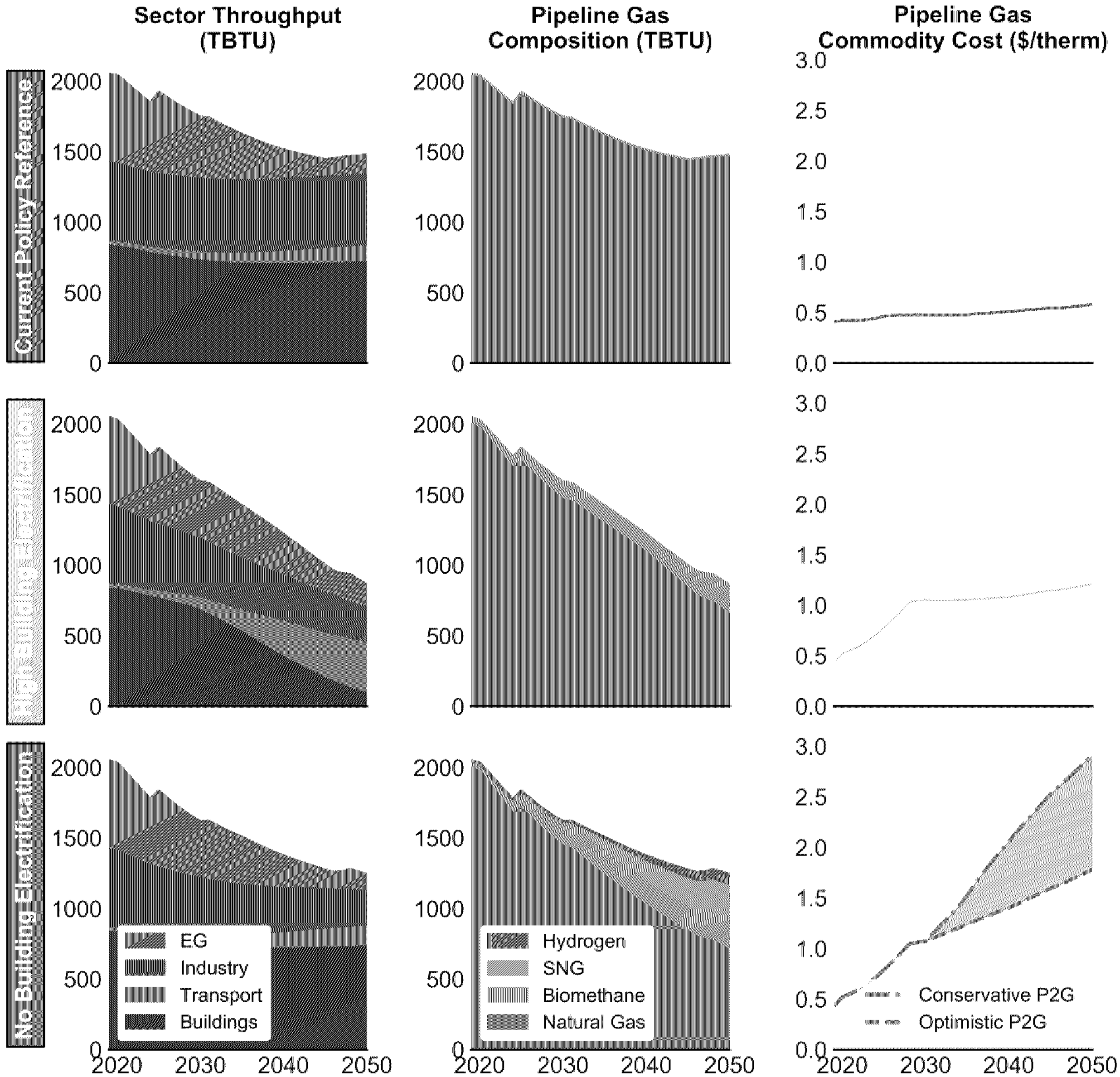
Natural Gas Throughput and Commodity Composition

Natural gas throughput declines in all scenarios. In the reference scenario, natural gas electricity generation declines markedly as renewables displace natural gas because of modeled implementation of SB 100 (Figure 11). In the no building electrification scenario, high energy efficiency and reduced petroleum industry energy demand (included in both mitigation scenarios) further reduce natural gas demand. However, natural gas demand in buildings remains relatively flat in this scenario (and in the reference), with efficiency offsetting population and economic growth. In the high building electrification scenario, in contrast, natural gas demand in buildings falls precipitously post-2030, reaching an 89 percent reduction by 2050, and is on pace to decline further beyond 2050.

The throughput declines in each scenario follow from the respective decarbonization strategies. In the high building electrification scenario, decrease in gas throughput is a key source of emissions reduction as electricity is used to displace gas use in buildings. A blend of 25 percent biomethane plays an important role in reducing the GHG emissions intensity of remaining pipeline gas demands. In the no building electrification scenario, hydrogen and SNG are blended in addition to biomethane to reduce GHGs from natural gas consumption. These RNG blends increase the aggregate, or combined, pipeline blend commodity cost, especially in the no building electrification scenario, where the commodity cost reaches \$1.8/therm in the optimistic P2G cost scenario and \$2.9/therm in the conservative P2G cost scenario.[22] The authors emphasize that this blended commodity cost assumes that 56 percent of the pipeline gas is natural gas. The commodity cost in a completely decarbonized gas pipeline would be between \$5.5 per therm and \$9.0 per therm if SNG were used to displace all remaining fossil fuel.

22 In the reference scenario, commodity costs of fossil natural gas increase only modestly to \$0.59/therm based on the Energy Information Agency (EIA) Annual Energy Outlook (AEO) forecast for the Pacific region.

Figure 11: Gas Throughput, Pipeline Gas Composition, and Pipeline Gas Blend Commodity Cost in PATHWAYS Scenarios



Pipeline commodity costs do not include gas transmission, storage, or distribution costs. Biomethane shown in the reference scenario corresponds to biogas used in CNG trucks. Throughput figures in these charts are based on gas utility loads and do not include use of nonutility gas for enhanced oil recovery steaming or cogeneration.

Source: E3

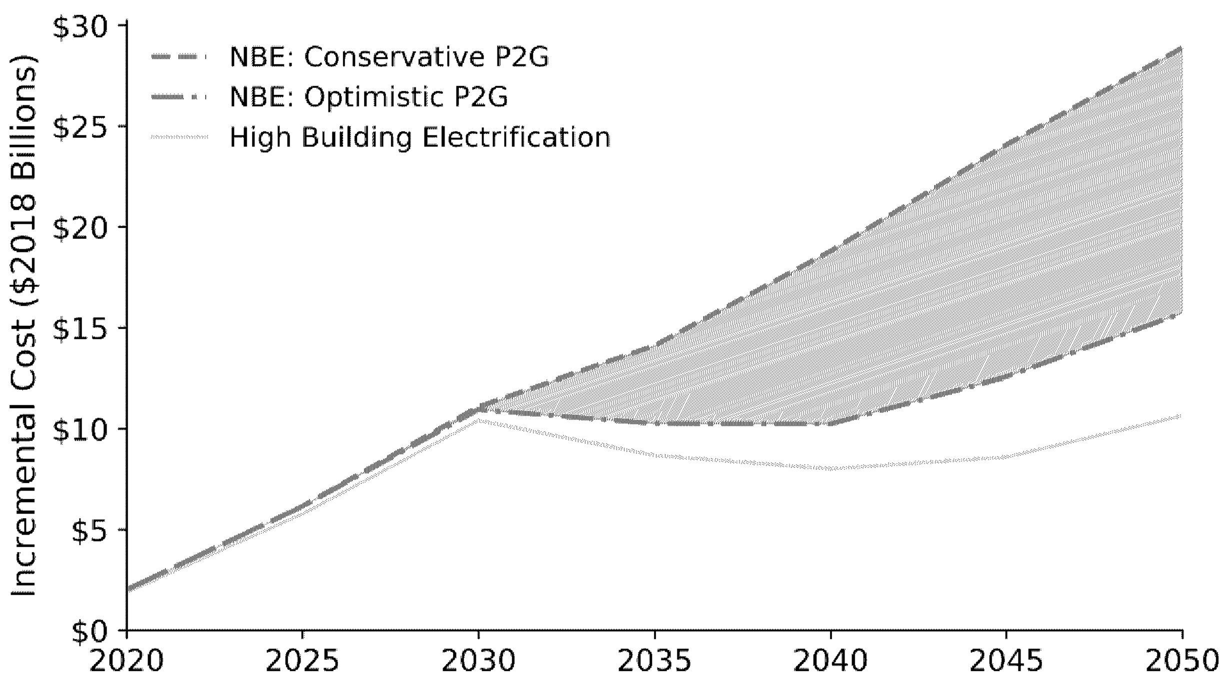
Economywide Costs

Similar to the results in Mahone et al. (2018), high reliance on building electrification is projected to lower economywide costs relative to a scenario in which building electrification is excluded (Figure 12). The costs of the high building electrification and no building electrification scenarios are similar through 2030 because both scenarios include a similar set of GHG mitigation measures through this time frame to meet the state's 2030 GHG reduction goal. The costs of the scenarios diverge after 2030 as increasing quantities of expensive hydrogen and SNG are blended into the pipeline in the no building electrification scenario. The conservative and optimistic P2G cost scenarios bracket a wide range of economywide costs in the no building electrification scenario. However, even in the optimistic P2G cost scenario, the scenario cost is greater than in the high building electrification scenario and on an upward trend, as increasing quantities of RNG are required over time.

Importantly, the high building electrification scenario costs shown in Figure 12 assume no retirement of natural gas distribution infrastructure. Put another way, this scenario assumes all the gas infrastructure continues to be paid for, despite declining throughput. The total cost for this scenario could be lower if gas distribution system costs were reduced. However, the high building electrification scenario also does not assume any early retirement of gas equipment, which would tend to increase the cost of this scenario. See Chapter 5 for a discussion of the challenges associated with reducing gas system capital expenditures.

Overall, the cost difference between the high building electrification and the reference scenario is smaller than the difference between "high electrification" and "current policy reference" in Mahone et al. (2018), particularly after 2030, owing primarily to assumed lower costs for wind and solar generation, battery storage, and biofuels. In addition, the reference scenario now includes a nearly decarbonized electricity system, reducing the net electricity system costs of the 80 x 50 scenarios. Similar quantities of biofuels are used in the high building electrification and no building electrification scenarios so the biofuels costs have little effect on the relative costs of those two scenarios.

Figure 12: Economywide Annual Net Costs, Relative to Current Policy Reference Scenario



NBE is short for "no building electrification" scenario. The high building electrification scenario does not assume any retirements of natural gas distribution infrastructure. Transfer payments such as cap-and-trade and LCFS policies do not affect the total costs to the California economy shown here.

Source: E3

In addition to being lower cost, the high building electrification scenario is likely lower risk than the no building electrification scenario. The high building electrification scenario relies on the implementation of commercialized technologies in buildings, while the no building electrification scenario relies on the commercialization of electrolytic fuels, as well as deeper, and potentially more speculative, GHG mitigation strategies in other sectors, including the heavy-duty transportation and industrial sectors.

In addition, building electrification could serve as a risk reduction strategy to protect low-income and vulnerable communities from future gas rate increases. Conversely, if building electrification is delayed, missing the lower-cost opportunities for all-electric new construction and replacement of equipment upon failure, there is a greater risk that expensive early retirement of equipment may be needed, or that the climate goals could be missed.

Remaining Emissions in 2050 and Implications for Carbon Neutrality

The no building electrification scenario allocates nearly half of the 2050 fossil energy emissions budget to buildings (Figure 13). In contrast, the high building electrification scenario has eliminated most emissions from buildings and is on track to reduce them further as remaining natural gas appliances reach the end of useful life.

This study focused on modeling scenarios reaching the 80 x 50 goal, but Executive Order B-55-18 of 2018 set a more stringent goal of a carbon-neutral California by 2045. While it is not known exactly what combination of measures might be employed to meet the carbon neutrality goal, additional direct reductions in GHG emissions are likely needed relative to an 80 x 50 scenario, in addition to direct air capture and other carbon removal strategies. In short, both 80 x 50 scenarios modeled here would likely require additional GHG mitigation measures throughout the economy to achieve net-zero GHG emissions. However, the high building electrification scenario may be better placed to reach that goal because it has more remaining low-cost options to decarbonize transportation and industry, whereas these are already used in the no building electrification scenario to make up for continued emissions in buildings. Bringing down the building sector emissions in the no building electrification scenario to match those in the high building electrification scenario by 2050 would require using SNG with DAC, as other less expensive RNG options are already fully used. This option would cost $4.1 to $8.6 per therm in commodity cost, assuming the optimistic and conservative P2G cost scenarios, respectively, relative to $0.59/therm fossil natural gas. This would result in an additional economywide cost of $11 billion to $24 billion per year in 2050.

Scenario Discussion

Understanding the Economywide Cost Results

Based on the finding that there is likely to be insufficient biomethane available to fully decarbonize the natural gas system, decarbonized electrolytic fuels are likely to be required. These fuels require zero-carbon electricity generation.[23] The electricity generation requirement can be compared with using the electricity directly in a heat pump to serve the same heating demand.

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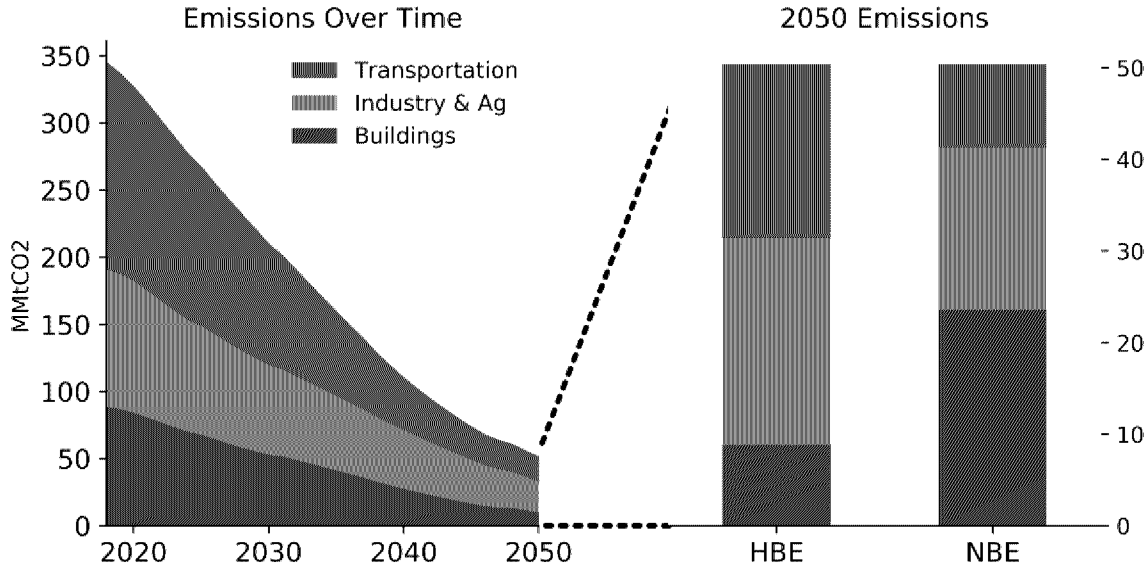
23 An alternative would be using hydrogen produced from fossil NG with steam methane reformation coupled with CCS or nuclear and upgrading the pipeline infrastructure and appliances to use greater blends of hydrogen. This alternative was not modeled in this study but may be worth further study, particularly if higher hydrogen blends in the pipeline system are possible without major system upgrade costs.

Figure 13: Energy Emissions by Sector



Energy emissions by sector include upstream emissions in electricity in this chart.

Source: E3

The life-cycle primary energy efficiency[24] of using zero-carbon electricity to provide building space heating ranges from about 300 to 500 percent, accounting for heat pump efficiency and 7 percent electricity transmission and distribution losses. This amount equates to about 0.1 kilowatt-hour (kWh) of electricity generation input for 1 kBtu of heat delivered. In contrast, producing SNG from DAC or bio-CO_2 and then burning this in a natural gas furnace provides about 35 to 53 percent primary energy efficiency accounting for conversion losses, or about 1 kWh of input electricity for each 1 kBtu of heat delivered, given 45 to 56 percent production efficiency (Chapter 2) and a combined 77 to 95 percent efficiency for delivery and furnace operation.[25]

More broadly, this is an example of a principle emerging from a consensus in the deep decarbonization literature (for example, Committee on Climate Change 2019) of reserving biofuels and synthetic fuels for the sectors that are the most challenging to electrify, where required energy density or lack of efficiency benefit from electrification makes electrification most challenging. With known technologies, low-cost, sustainable liquid and gaseous fuels are likely to be scarce in any low-carbon future; so they are likely best targeted to uses like aviation, freight, industrial high-temperature heating, and backup thermal electricity

24 This is defined as the ratio of the delivered useful energy (that is, heating service) to the energy in the form of renewable electricity generation to serve this use. Conversion losses in fuel production, losses in transmission and distribution, and wasted energy in heating systems reduce this ratio.

25 The Energy Information Administration estimates about 3 percent consumption of natural gas within the pipeline system itself, which is not modeled here (EIA 2017).

generation. Because buildings can be electrified at high efficiency with existing technology, this sector is a less ideal candidate to absorb a large proportion of RNG supply.

Monthly Operating Costs for Completely Decarbonizing Space Heating Using Electricity or RNG

The order of magnitude difference in primary energy efficiency drives large differences in the projected costs of decarbonizing space heating using these two approaches (Figure 14). Assuming that space heating is fully decarbonized[26] by either a heat pump powered by decarbonized electricity or 100 percent RNG, this analysis finds that the heat pump would cost from $34 to $53 per month to operate, while RNG in a gas furnace would cost from $160 to $263 per month to operate.

For this calculation, the research team assumed that space heating service demand averaged 29 therms per month, based on the PATHWAYS assumption for a single-family home in the PG&E service territory. Then, the team calculated the energy demand as the service demand divided by the efficiency. To make a direct comparison, researchers express units of energy consumed in therms (1 therm = 29.3 kWh). In California's mild climate, heat pumps can deliver an equivalent amount of heat with less than one-fifth the site energy of a gas furnace.[27] In 2020, the statewide residential electricity rate is projected to be $5.30/therm, several times the gas rate of $1.60/therm, and could be higher if wildfire-related costs and liabilities are passed on (Chapter 4). This rate partially offsets the higher efficiency of the heat pump in 2020, yielding a monthly cost estimate of $34 to $53 to run the heat pump vs. $38 to $57 to run the gas furnace.

However, the difference is greater in 2050 with decarbonized electricity and gas. PATHWAYS projects an electricity rate of $5.90/therm in 2050 in the high electrification scenario, but given uncertainties in electric sector costs, this study shows a range of results up to $7.70/therm, resulting in a monthly cost range from $34 to $44 for a heat pump. The gas rate in the no building electrification scenario if the RNG blend were increased to 100 percent would range from $5.50 to $9.00, according to the optimistic and conservative P2G cost scenarios, respectively. Even assuming a 98 percent condensing gas furnace, this scenario yields a monthly cost of $160 to $263 to operate a gas furnace. The 2050 Reference scenario result is included as a conservative comparison, in which electricity is decarbonized because of SB 100, but the natural gas blend remains 100 percent fossil. Even in this case, operating costs of a heat pump space heater would be expected to be lower than those of the gas furnace.

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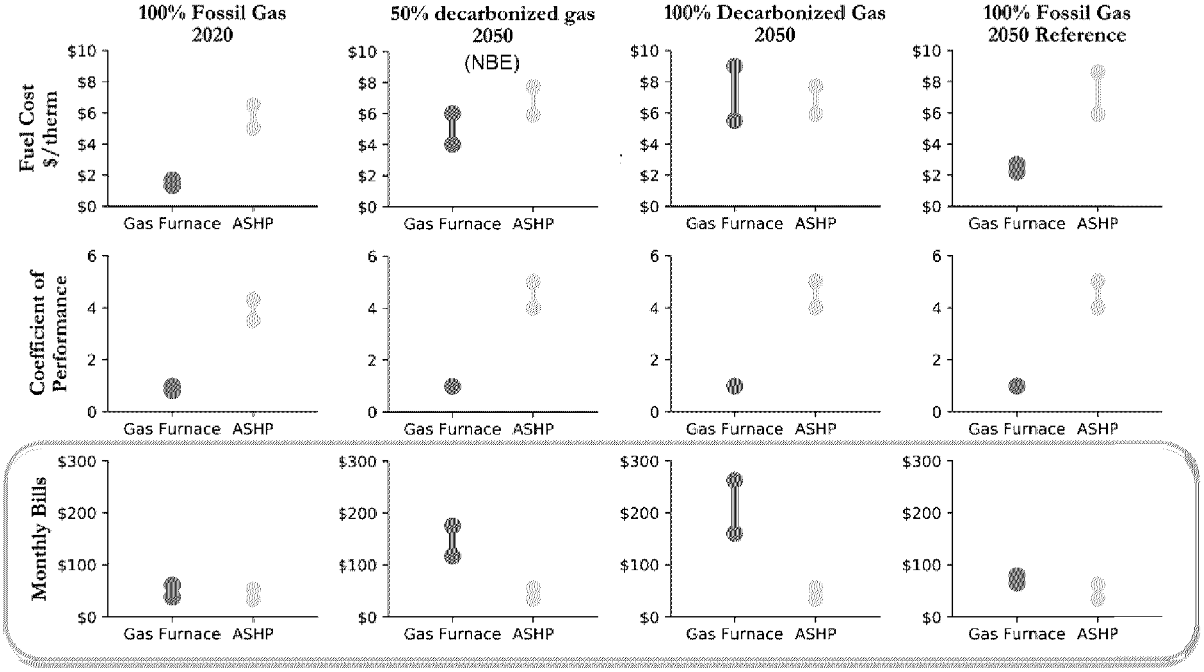
26 A small amount of emissions would remain in both cases because of 5 percent natural gas generation in electricity and any unmitigated fugitive methane emissions from the pipeline system and end uses.

27 In today's electricity system, site energy, a measure of direct energy consumption on-site (rather than "source energy", which includes upstream energy consumption associated with electricity generation), is a somewhat incomplete metric given thermal losses that occur in generating electricity in combustion-based power plants. However, these scenarios assume that California's electricity shifts to a largely noncombustion-based system, at which point the site-energy versus source-energy distinction is less meaningful.

Figure 14: The Cost of Residential Space Heating Using Electricity, Natural Gas, and 100 Percent Renewable Natural Gas



Notes: Statewide average residential electricity and natural gas rates in 2020 and 2050 from PATHWAYS scenarios are shown. The electricity rate range encompasses the wildfire cost sensitivity (Chapter 4), while the gas rate range encompasses the conservative and optimistic P2G cost scenarios and, in 2020, the range between PG&E and SCG rates. To estimate the gas rate with 100 percent RNG, SNG with DAC is used as the marginal resource to displace the remaining fossil NG from the no building electrification scenario. The appliance efficiencies (that is, coefficients of performance, the ratio of output heat to input fuel energy) are chosen to reflect moderately high-efficiency options on the market for 2020, up to the highest efficiency available shown as the high end of the range in 2050. Heat pump performance is based on the Sacramento-area climate. In the reference, the electricity is assumed to be largely decarbonized in 2050 because of SB 100, while the natural gas blend would still be 100 percent fossil.

Source: E3

Because the costs of operating a heat pump space heater are expected to be lower than the costs of operating a gas furnace even with 100% fossil natural gas in 2050, some economic electrification is likely to occur in any case, which will lead to upwards pressure on gas rates that could create a self-reinforcing feedback loop (Chapter 4). For this reason, the economic challenges of decarbonizing the gas system largely with RNG are likely robust to even faster cost declines in RNG than modeled here. These challenges are exacerbated by 7% (by energy) blend limit for hydrogen in the distribution system without infrastructure and appliance upgrades. Combined with the limited supplies of biomethane, this means that the marginal RNG resource in the absence of electrification is likely to be SNG. Projected costs of this commodity, which is not commercially available today, would have to decline far faster than modeled here in the optimistic P2G cost scenario to be competitive with fossil natural gas or with operating a heat pump.

Air Quality Results

The UCI team assessed regional, outdoor air quality impacts in 2050 under the three PATHWAYS scenarios and a fourth scenario where the high electric and fuel cell trucks measure from no building electrification is incorporated into high building electrification. The research team did not assess the effects of gas combustion on indoor air quality in this study.

Researchers took emissions outputs from PATHWAYS and ran them through an emissions processing system, the Sparse Matrix Operator Kernel Emissions tool (SMOKE), to determine the composition of criteria air pollutant emissions and allocate them by geographic location and time. The Community Multi-Scale Air Quality Model Version 5.2 (CMAQv5.2) tool then established fully developed distributions of concentrations for two criteria air pollutants: $PM_{2.5}$ and tropospheric ozone. $PM_{2.5}$ and tropospheric ozone are used to assess air quality because of their association with human health impacts because many regions in California experience ambient levels in excess of state and federal standards. The team calculated average and peak ground-level concentrations of $PM_{2.5}$ and tropospheric ozone for a summer episode (July 8-21) and winter episode (January 1-14) to capture the effect of seasonal variation in meteorology and emissions concentrations. The Benefits Mapping and Analysis Program-Community Edition (BenMAP-CE) tool then estimated the avoided incidence and economic value of health impacts from short-term exposure to ozone and $PM_{2.5}$ during these periods.

Overall, the no building electrification scenario had a larger and more widespread impact on ozone than the high building electrification scenario because of the larger reduction of HDV emissions. However, the high building electrification scenario had larger reductions in $PM_{2.5}$, especially during the winter episode. This impact on $PM_{2.5}$ follows from secondary effects from building NO_x emissions. The scenarios are not directly comparable in that emission reductions from buildings and HDV are not equivalent in scope, that is, a larger penetration of electrification is assumed in buildings relative to alternative measures assumed for HDV.

Health savings for the three alternative scenarios as a result of air quality improvements relative to the reference scenario are shown in Table 3 below. While health savings are similar between the high building electrification and no building electrification scenarios for the summer episode, there are larger health savings in the high building electrification scenario for the winter episode because of the larger impact on $PM_{2.5}$ during the winter. While both building electrification and truck measures lead to air quality improvements and health savings, the highest benefits are achieved when the measures are combined.

Table 3: Mean Health Savings for Air Quality Improvements Estimated for Summer and Winter Episodes in 2050

Episode	High Building Electrification	No Building Electrification	High Building Electrification With Trucks
Summer	$202	$202	$261
Winter	$190	$166	$249

Mean health savings in million $/episode.

Source: UCI APEP

While annual health savings cannot be estimated from the episodic modeling method used in this study, the use of long-term exposure $PM_{2.5}$ health impact functions like those used in a recent analysis of air quality impacts in California[28] would lead to substantially higher health benefits for all scenarios. The full draft air quality impacts assessment by UCI can be found in Appendix F.

Other studies have investigated the impacts of natural gas cooking on indoor air quality (Logue et al., 2013) and the impact of gas appliances more generally on indoor air quality (Mullen, 2012). Logue et al. (2013) conclude that using natural gas cook stoves without venting range hoods can expose a substantial proportion of residents to pollutant concentrations that exceed health-based standards and guidelines for outdoor air quality. Logue uses simulated results to evaluate only emissions from natural gas combustion, not emissions from cooking food. While Logue concludes that indoor air pollution from natural gas cooking burners can be reduced, but not eliminated, through the use of current venting range hoods, Mullen's empirical results showed no statistical association between the use of a kitchen exhaust fan and pollutant concentrations in California homes.

28 Alexander et al. 2019. *Air Quality Implications of an Energy Scenario for California Using High Levels of Electrification*. California Energy Commission. Publication Number: CEC-500-2019-049.

CHAPTER 4: Implications for Natural Gas Customers

This chapter explores the customer energy rate and bill impacts of the PATHWAYS scenarios described in Chapter 3. It examines the effects of those scenarios on customers who electrify their homes and businesses and those who do not. This distinction is particularly important from an energy equity and environmental justice perspective. While some customers may prefer to continue to use gas even if it becomes more expensive than electricity over time, other customers may not be *able* to electrify, regardless of potential energy bill savings. For instance, low-income customers have more limited access to capital and may not be able to afford the upfront costs associated with a building retrofit (Scavo et al 2016). Renters do not own their buildings, so they typically have little to no say about what types of equipment are installed in their homes and businesses.

To assess the energy equity and energy bill effects of different low-carbon scenarios, the research team developed a representation of the revenue requirements of California's natural gas distribution utilities. That analysis, paired with scenarios of gas throughput and pipeline composition from PATHWAYS, allowed the research team to develop estimates of gas rates and bills for each scenario through 2050.

California's Energy Cost Challenge

California's electric and natural gas systems face daunting cost challenges. A common driver of increasing costs among electric and natural gas utilities are recent safety-related incidents. Incidents like the San Bruno gas pipeline explosion and Aliso Canyon gas storage field leak have spurred renewed investment in the state's gas infrastructure. The state's electric system also faces increasing costs following a series of catastrophic wildfires attributed to ignitions from electric infrastructure. These fires are expected to put upward pressure on electric utility rates because of expected damages owed to victims of the fires, a portion of which will be passed onto ratepayers, and utility costs associated with reducing future wildfire risks.

The cost impacts of safety-related investments are already being felt. Gas utilities in California are in the midst of large safety-related investments, and those investments are expected to increase gas rates over the next three years. PG&E has requested an increase of 15 percent for its gas revenue requirement, and a recent decision in SCG's rate case will increase that utility's revenue requirement by 25 percent ($2018 real) from 2018 to 2022. (PG&E 2018, CPUC 2019). As of this writing, these applications have not yet been decided upon at the CPUC.

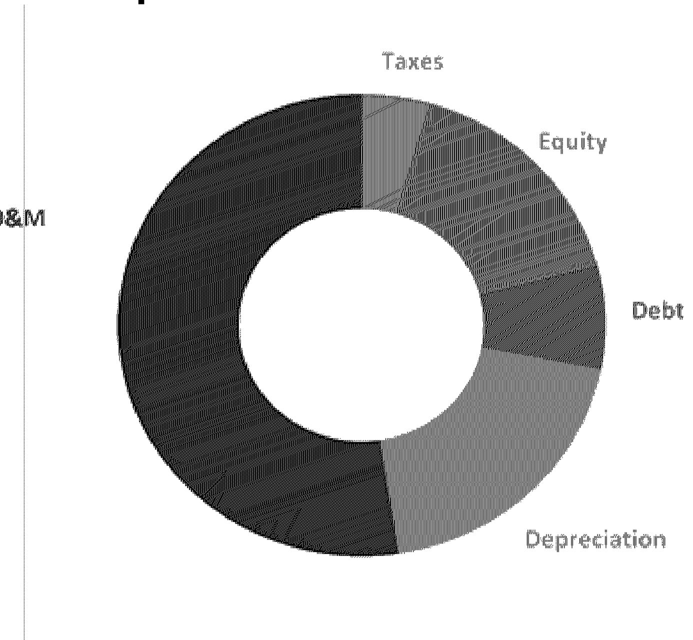
The extent and duration of wildfire-related electric system cost increases are not yet known. However, California's investor-owned electric utilities have proposed substantial increases in their cost of capital in response to the large liabilities wildfires present to their systems under the state's current liability standards (PG&E 2019, SCE 2019). Utilities have also begun to implement the set of operational expenditures and investments required to reduce the risk of wildfires associated with their systems. These expenditures will increase the cost of serving the state's electric loads, although the extent and duration of those cost increases, and how they will be allocated among electric customers, are not yet known.

The Financial Structure of the California Gas System Today

The California Public Utilities Commission regulates natural gas utilities in California. Gas utilities file their planned revenue requirement and rates on three-year intervals and are allowed the opportunity to earn a fair return on their investment in return for safe, reliable gas service to their customers. The gas utility revenue requirement covers the infrastructure and operational costs associated with delivering gas to homes and businesses in California, not the commodity cost of natural gas itself.

To evaluate the financial implications of decreased throughput on California gas utilities, the research team developed a gas revenue requirement model for PG&E and SoCalGas. The revenue requirement model captures the set of operational and investment expenses associated with delivering gas through those utilities' systems. The revenue requirement model developed by the research team is benchmarked to each utility's most recent general rate case (GRC) filed with the CPUC.[29] PG&E and SoCal Gas comprise roughly 94 percent of gas utility throughput in California. After combining those two utilities' revenue requirements and scaling by their proportion of total statewide gas utility load, this analysis estimates that the gas utility revenue requirement in California is $7 billion in 2019. Operational costs are just over half the statewide gas revenue requirement, while costs related to capital expenditures are responsible for most of the remainder. Those costs include annual depreciation expenses, payments to holders of debt, equity returns and taxes (Figure 15).

Figure 15: Composition of California's Gas Revenue Requirement



Source: E3

Importantly, the utility financial data obtained from these regulatory filings do not readily distinguish between costs to provide and maintain gas service to new gas interconnections and

29 The research team relied on the following regulatory filings to build and benchmark the revenue requirement models: PG&E GCAP 2018, PG&E GRC 2020, PG&E GTS 2019, SCG TCAP 2020, SCG GRC 2019, SCG 2017 PSEP Forecast Application, SCG PSEP Forecast application.

costs to maintain and operate the existing gas system. As such, the E3 gas revenue requirement model is not designed to explicitly estimate the gas system cost savings from, for example, all-electric new construction. Rather, the tool is designed to test broad scenarios around what the effect on gas revenue requirements and rates would look if a reduction in total gas system expenditures were achieved.

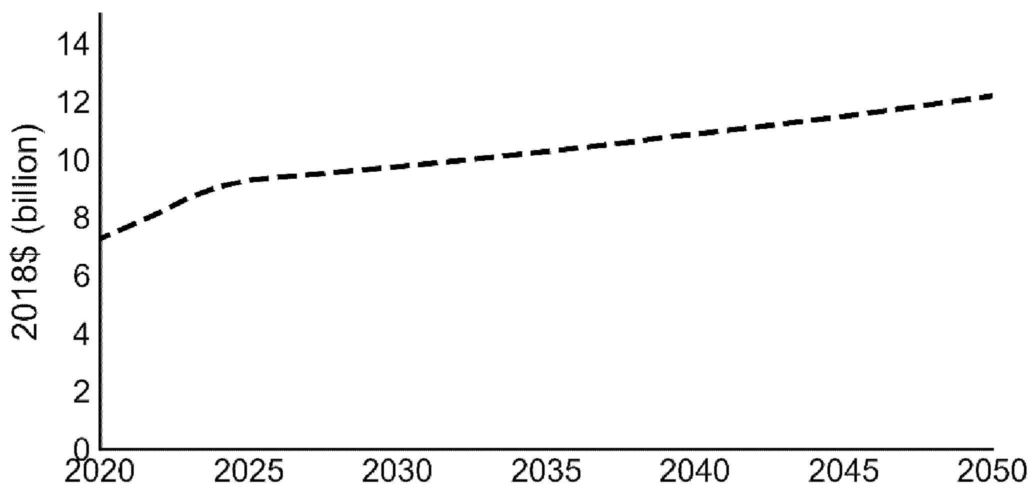
Investor-owned utilities (IOU) provide delivery service to most gas customers in California but sell only commodity gas to a subset of customers in the state, called "core" customers. Core customers include all residential customers, some commercial customers, and a small number of larger users like industrial facilities or electric generators. "Noncore" customers contract for commodity gas with non-IOUs but pay for delivery service via the regulated utility. These customers tend to be larger users and are often connected to higher-pressure segments of the gas system.

Gas Revenue Requirement — Reference Scenario

The reference scenario gas system revenue requirement is meant to represent a future where California continues to use and invest in its gas infrastructure. This near-term forecast of the state's revenue requirement is based on 2018 – 2019 general rate case requests from PG&E and SoCalGas, and the September 2019 CPUC decision on the SoCalGas GRC. In those rate cases and related regulatory documents, both utilities outline a series of ongoing safety-related investments that lead to a sharp increase in their respective revenue requirements in the near term (SCG 2017). This analysis assumes that those large, incremental safety-related investments continue through 2025, at which point the state's revenue requirement has reached $9 billion annually, compared to about $7 billion today, a 28% increase in real terms over a 7-year period.

Costs further out in time are more speculative. This study assumes costs continue to increase as gas utilities reinvest in their systems. Historical experience suggests that the costs of system reinvestments increase over time, in real terms, because of escalation of both operations and investment costs (WRA 2018, CPUC 2019). The result is that by 2050, the state's gas revenue requirement is estimated at $12.2 billion in the current policy reference scenario, 80 percent higher than today's value.

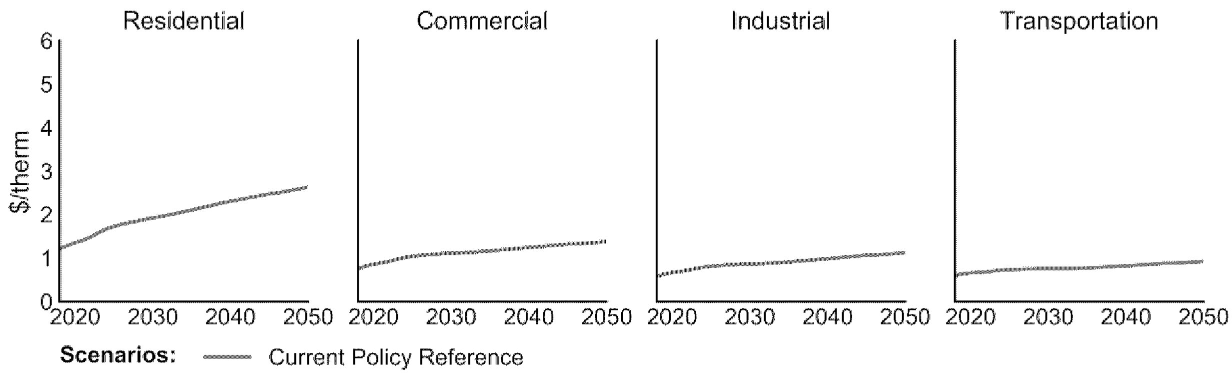
Figure 16: Reference Gas Revenue Requirement



Source: E3

The state's gas revenue requirement is expected to increase, but gas throughput is expected to decrease. Gas rates are, at a high level, based on the average cost of service. If costs increase but gas demand does not, rates will rise. That phenomenon is borne out in the PATHWAYS current policy reference scenario, where rates increase for all customer classes.

Figure 17: Reference Gas Rates by Sector



Source: E3

Costs of the Gas System in Mitigation Scenarios

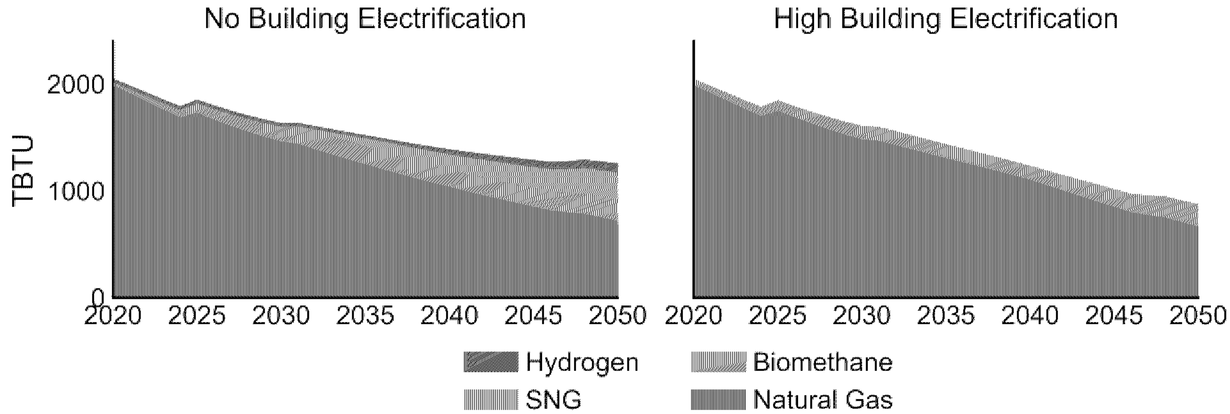
California's gas system faces transformations in all scenarios that achieve an 80 percent reduction of GHGs from 1990 levels by 2050. Those changes include decreased throughput and a shift in the composition of commodity gas flowing through the system.

Gas Commodity Costs

The composition of gas changes in California as a share of natural gas in each scenario is replaced with either climate-neutral methane or renewable hydrogen. Those fuels carry incremental costs above natural gas, so the blended cost of the commodity flowing through the gas system will increase over time as well. As discussed in Chapter 3, the rank order of climate-neutral pipeline gases from least to most costly is biomethane, hydrogen, and SNG. All mitigation scenarios blend biomethane into the pipeline. Where the mitigation scenarios differ is in the associated use of the more expensive hydrogen and SNG commodities. The high building electrification scenario does not require these electrolytic fuels to meet the state's 80 percent reduction by 2050 (80 x 50) climate target. In contrast, the no building electrification scenario has higher gas system throughput. As a result, SNG and hydrogen are used in this scenario to reduce emissions from gas use enough to meet the state's 80 x 50 climate target.

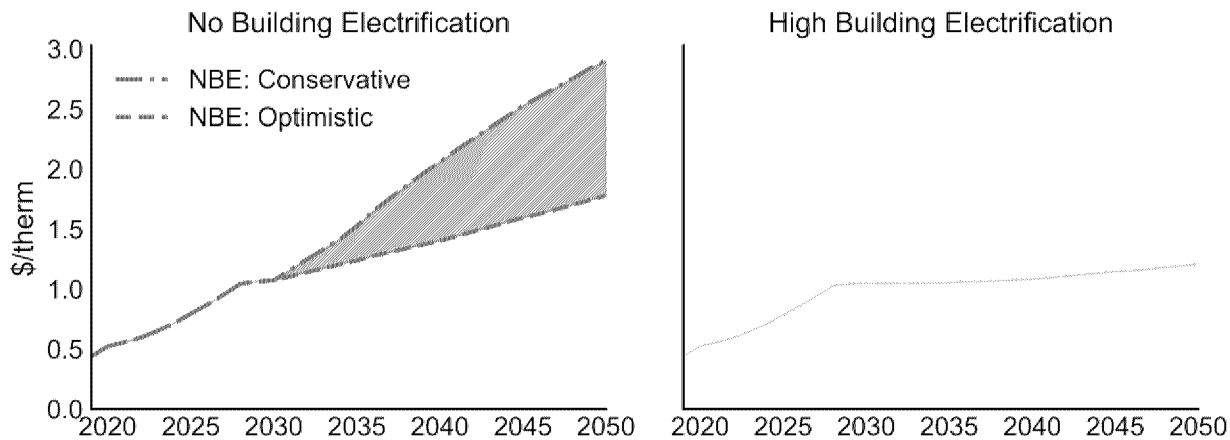
The use of hydrogen and SNG in the no building electrification scenario leads to a pipeline gas commodity cost that is four to seven times higher than today in 2050. Whereas commodity natural gas costs less than $0.4 per therm today, by 2050, the blended pipeline commodity cost is between $1.4 and $2.4 per therm in the no building electrification scenario. The high building electrification scenario sees a more moderate gas commodity cost increase ending with a 2050 cost of $0.75 per therm.

Figure 18: Pipeline Gas Demand and Fuel Blend (Million Therms)



Source: E3

Figure 19: Blended Commodity Cost by Scenario



Notes: "Conservative" and "Optimistic" refer to the respective P2G cost scenarios.

Source: E3

Gas System Revenue Requirement and Cost Recovery

As long as California's gas system is being used, that system will require continued reinvestment to ensure safe and reliable service. California's gas system has many components, ranging from interstate pipelines to the distribution laterals that connect homes and businesses to gas supply. For the gas revenue requirement analysis, the research team separated the gas system into two segments:

1. Transmission and underground storage: The gas transmission system is used to transport gas from each utility's citygate (that is, the connection to the interstate gas pipeline system[30]) to load centers. Underground storage is used to ensure a sufficient

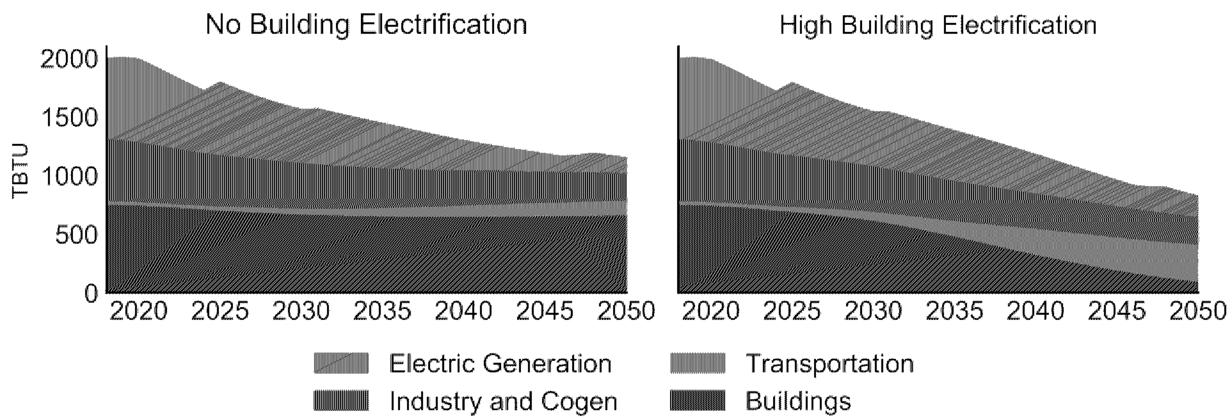
30 This study assumes that costs associated with the interstate pipeline system are captured in the basis differential (the gas price difference between regions) incorporated in EIA natural gas commodity cost forecasts. An examination of how that basis differential could change under lower levels of gas throughput nationally is beyond the scope of this analysis.

quantity of natural gas is available in the state during periods of high load. The gas storage system also plays an important role in hedging commodity gas costs.

2. Distribution: The distribution system delivers gas from the transmission and underground storage systems to end users. It has the largest footprint of any portion of the system. For instance, PG&E has more than 42,000 miles of distribution pipeline compared to 6,400 miles of transmission pipeline (PG&E 2019b). In Sempra Energy's 2019 10-k filing, they report over 114,00 miles of distribution pipeline, compared to just over 3,000 miles of transmission pipeline for both San Diego Gas and Electric and Southern California Gas Company combined.

Both segments see a decline in utilization over the study period. The steepest declines modeled in these scenarios occur in the gas distribution system in the high building electrification scenario. The gas distribution system was largely sized to serve building heat loads. The high building electrification scenario switches those loads from the gas system to the electric system. Gas throughput also declines in the gas transmission system, largely because of the role of renewable generation displacing gas generation on the grid, but that decline is somewhat muted by sustained industrial sector usage and an increased role for CNG in heavy-duty transportation. Importantly, the gas transmission and storage system also may have a role to play in ensuring electric system reliability in any deep decarbonization scenario. Recent studies by E3 and others point to the importance of maintaining rarely used firm generation capacity to balance a future electricity system powered almost entirely by intermittent renewables (Sepulveda, 2018; Ming, 2019).

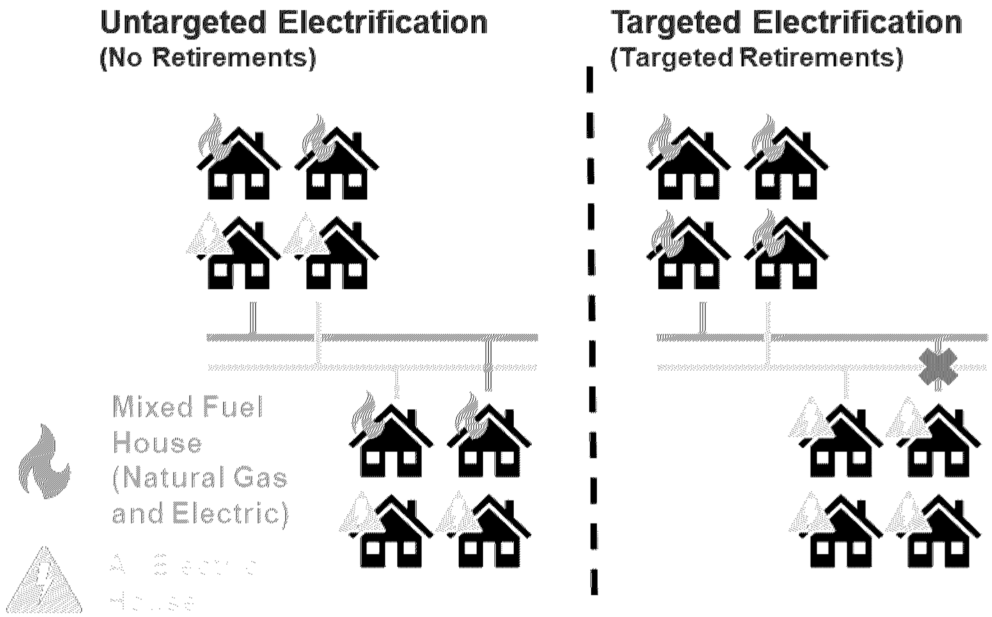
Figure 20: Gas Throughput by Sector



Source: E3

An open question is to what degree these changes in gas utilization will be accompanied by changes in gas system infrastructure and operations and maintenance costs. If a future gas system looks largely the same in terms of today's footprint and operations, it is likely that gas system costs will not change materially, despite lower throughput. On the other hand, decreased throughput could allow the expansion of the gas system to be halted, retirement of existing gas infrastructure, and cost savings on operations and maintenance expenses. These different worldviews implicate the expected future revenue requirement of utilities, the costs borne by customers that continue to receive gas service, and the consumer economics of building electrification.

Figure 21: Two Gas System Futures With and Without Targeted Electrification

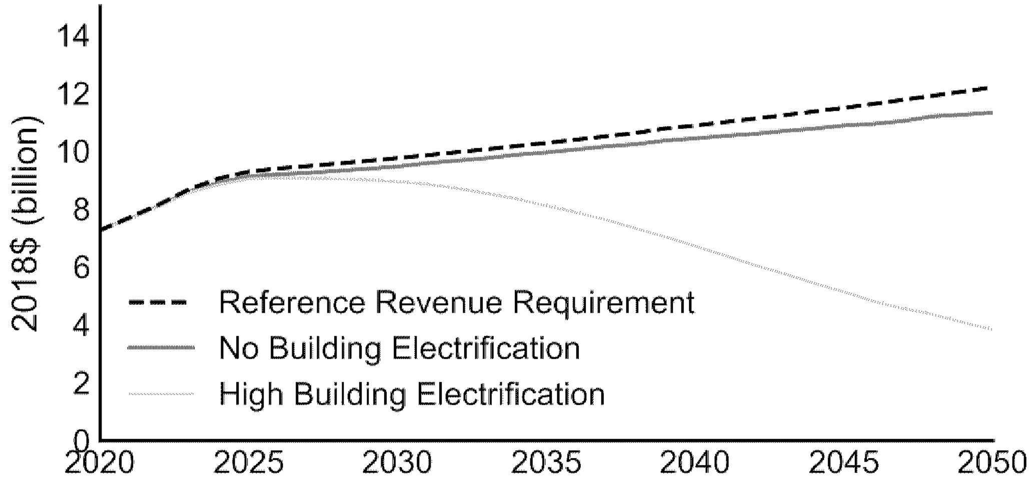


Source: E3

The base assumption of this study is that the gas system revenue requirement in both mitigation scenarios is equal to that of the reference case. This assumption is consistent with a future with scattershot electrification (that is, the left half of Figure 21, with "untargeted electrification"), where the costs of safely and reliably operating California's gas system would not change even as throughput decreased. To illustrate the magnitude of the cost recovery challenge in each scenario, this study compares the Reference revenue requirement against the revenues utilities would receive in those scenarios. The difference between the revenue requirement and revenues at reference rates in each scenario can be thought of as a cost recovery "gap." The gap for the no building electrification and high building electrification scenarios is shown in Figure 22.

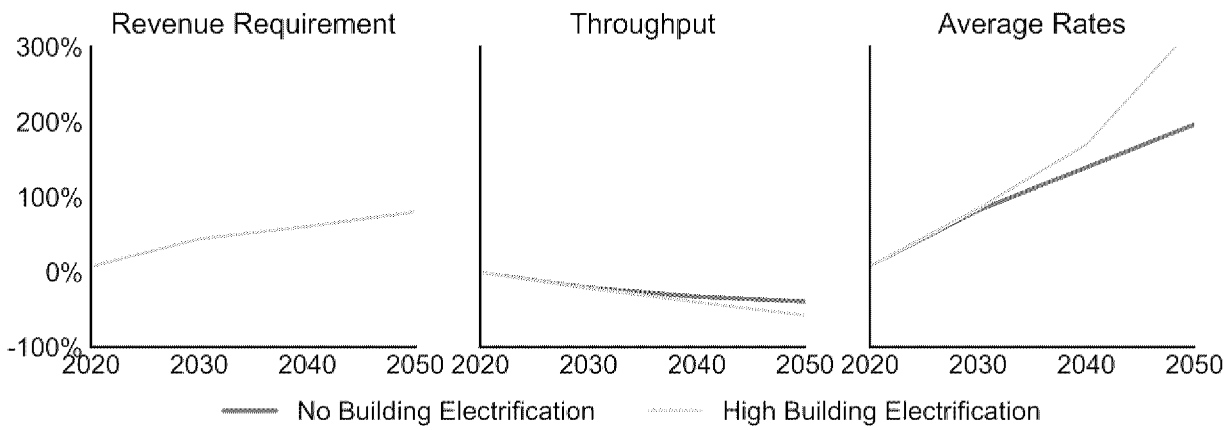
The default approach to close a gap between a utility's revenue requirement and its expected revenues is to increase customer rates. Gas delivery rates increase in both mitigation scenarios for all end users. Gas delivery rates increase above the reference scenario in the no building electrification and high building electrification mitigation scenarios. These rate increases stem from a combination of increasing costs and decreasing utilization. The largest decrease in gas system utilization occurs in the high building electrification scenario. In that case, increasing gas system costs are paid for by a rapidly shrinking set of customers. The results are rates that increase by 80 percent by 2030 and 480 percent by 2050).

Figure 22: Gas System Revenues in Mitigation Scenarios Assuming Reference Rates



Source: E3

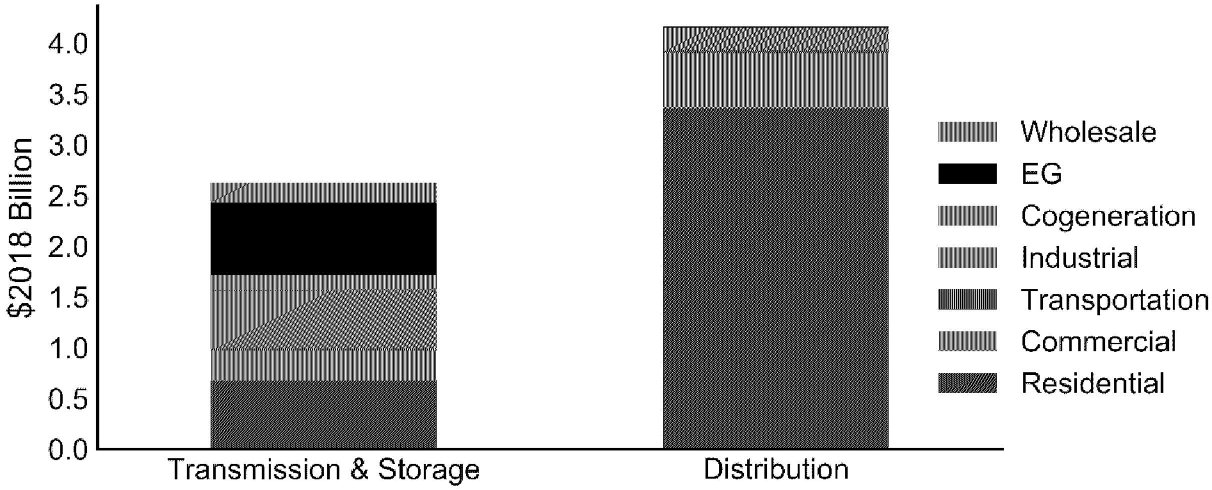
Figure 23: Percentage Increase Relative to 2019 in Gas Sector Revenue Requirement, Loads, and Average Rates



Source: E3

Rate increases are most marked for residential customers in the high building electrification scenario. This outcome follows from how gas system costs are allocated to customers. Recall that California's gas distribution system was largely sized to serve building heating loads. Large users—like those in the industrial sector—typically do not receive distribution-level service. As a result, residential and (to a lesser extent) commercial customers pay for the bulk of the distribution system, and the distribution system is the most expensive segment of California's gas infrastructure (Figure 24).

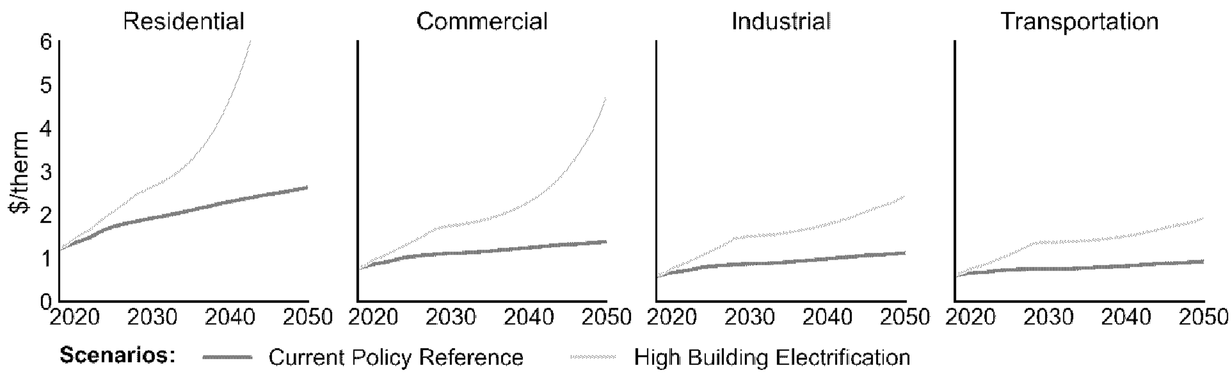
Figure 24: Estimated 2019 Gas System Revenues by Customer Type and System Segment



Source: E3

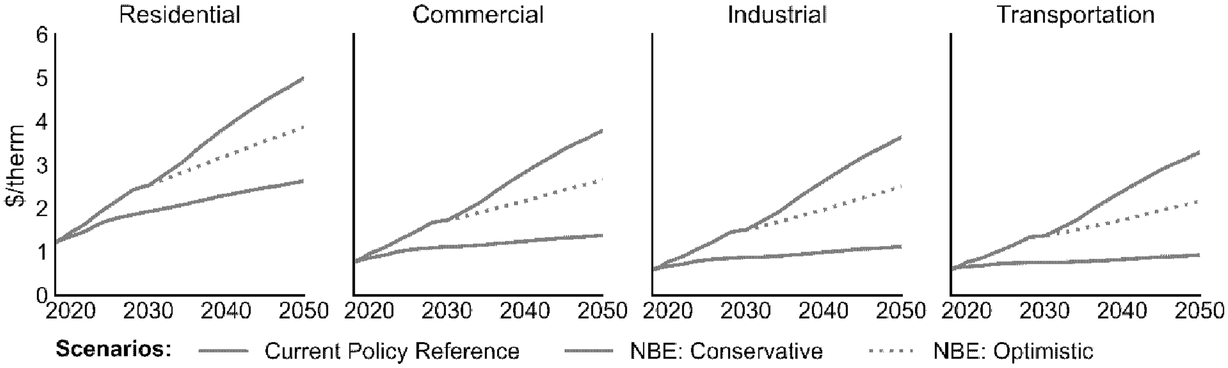
The average retail rate each customer class will pay includes commodity and delivery charges. Both elements of gas rates increase in both mitigation scenarios. The no building electrification scenario sees larger increases in the commodity cost of gas due to a higher blend of RNG. The high building electrification scenario sees a larger increase in the delivery charge because of decreasing utilization. The result is that the scenarios have different rates by customer class. The sectoral rate impacts of these scenarios are a function of the composition of the rates of those sectors. Delivery charges are a large portion of residential rates, while commodity charges are a large portion of industrial customers' rates. The result is that residential gas rates increase more in the high building electrification scenario, and industrial rates increase more in the no building electrification scenario.

Figure 25: Gas Rates by Sector in the High Building Electrification Scenario



Source: E3

Figure 26: Gas Rates by Sector in the No Building Electrification Scenario



Notes: "Conservative" and "Optimistic" refer to the respective P2G cost scenarios.

Source: E3

Electric Sector Rates

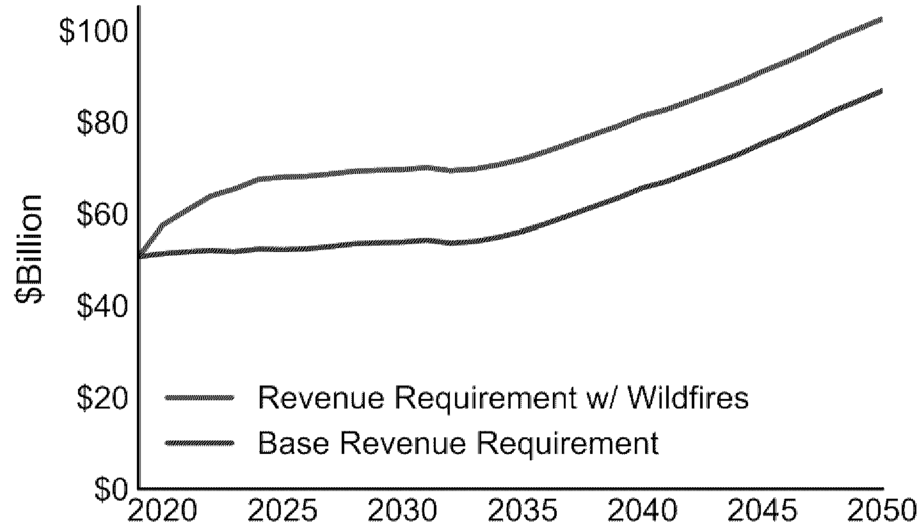
The electric sector is pivotal to enabling economywide decarbonization in all mitigation scenarios. Electrification-driven load growth increases annual on-grid electric loads by 24 percent in the no building electrification scenario and 43 percent in the high building electrification scenario. Furthermore, these new electric loads offer the possibility of providing flexibility to the grid, which could help reduce the cost of decarbonized electricity.

Like the California gas system, the state's electric system can also be expected to incur substantial new costs through 2050. These costs are driven by four main factors: 1) electrification-driven load growth, 2) large additions of new zero-emission electric supply resources and the storage necessary to integrate them, 3) business-as-usual costs such as the replacement of aging infrastructure and other cost escalations, and 4) wildfire-related, and other climate adaptation costs. The first two cost drivers are direct outputs of the PATHWAYS model. In PATHWAYS, load growth and electric power supply decarbonization lead to between a 52 to a 71 percent increase in the state's revenue requirement, depending on scenario. Business-as-usual cost increases are included in the Reference scenario forecast and are included in all other scenarios.

However, the exact magnitude and duration of wildfire-related costs, or other climate change adaptation costs, are less certain. To account for those increases, the research team developed a "wildfire cost" sensitivity case. To do so, researchers used PG&E's filing to collect wildfire-related costs over its next general rate case cycle (A. 18-12-009). If approved, those additional costs would increase PG&E's electricity rates 22 percent by 2022, though it is possible additional cost increases will be incurred beyond that period.

To develop a wildfire sensitivity, the study team assumed that this same percentage increase applies to the revenue requirement of all electric utilities, both public and private, in California. Like the gas system cost assumptions, increases in wildfire safety-related investments are assumed to attenuate by 2025, at which point they remain steady through 2050. An important caveat of this approach is that using PG&E costs may bias upward the near-term rate increases that can be expected statewide because PG&E has a larger share of its service territory in "high-risk exposure" areas of California than other utilities in the state (Wildfire Strike Force 2019). Furthermore, the assumption that all costs related to wildfires will be borne by ratepayers, and that those costs will be assessed on a purely volumetric basis, may not hold in practice. The cumulative effect of these incremental wildfire costs is a $20 billion per year increase in the revenue requirements of the state's electric utilities, as illustrated in Figure 29.

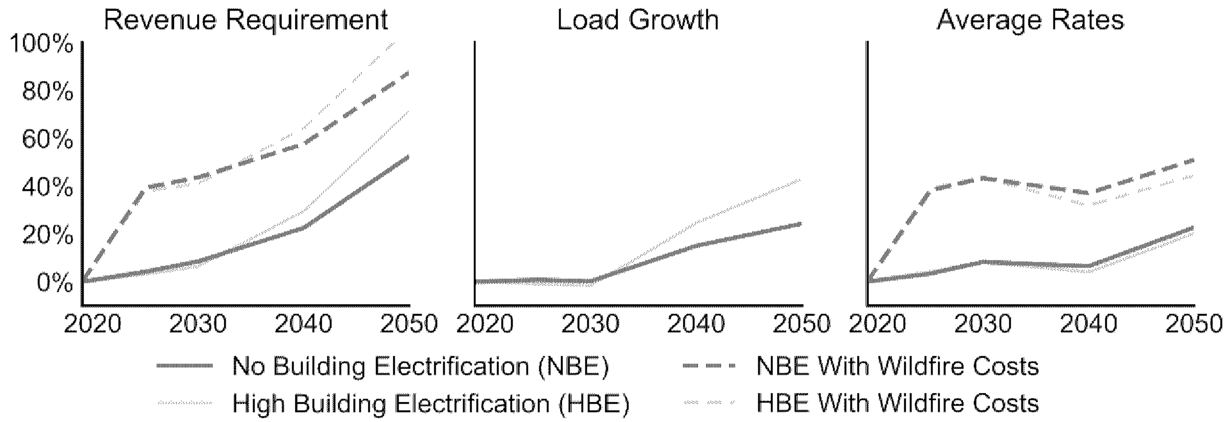
Figure 27: State Electric Revenue Requirement, High Wildfire Sensitivity



Source: E3

Despite those incremental costs, electric rate increases are relatively muted compared to those seen in the gas system. Absent wildfire costs, electric rates remain almost flat in near term and increase to 20 percent above today's rates by 2050. In the wildfire cost sensitivity, electric rates exhibit a marked near-term increase to 40 percent above today's rates but stabilize post-2030. In both cases, electric rates exhibit long-run stability because the state's rising electric revenue requirement is partially paid for by new electrification loads. This result differs from the Mahone 2018 results largely due to lower projected costs for renewable energy and energy storage technologies.

Figure 28: Percentage Increase in Electric Sector Revenue Requirement, On-Grid Loads and Average Rates



Source: E3

Residential Bills

To identify those potential utility bill impacts of these long-term, low-carbon scenarios, the research team developed an indicative residential bill impact analysis based on average rates. This analysis is intended to show directional changes over time between electric and gas customers, recognizing that there is wide variation among homes reflecting home type, home vintage, climate, utility, and rate design (as illustrated in Mahone 2019).

The residential customer bill impact analysis compares "mixed-fuel" IOU customers (buildings that use both gas and electricity) against "all-electric" IOU customers that have electrified their appliances. Specifically, mixed-fuel customers are defined as homes that have gas furnaces, water heaters, stoves, and clothes dryers and use electricity for all other uses in the home. All-electric customers are defined as those with homes that have electrified those four appliances.

This study finds that all-electric low-rise residential customers are likely to see lower total utility bills, on average, post-2030. In the near term, mixed-fuel customers are likely to see slightly lower utility bills than all-electric customers on average. This cost advantage erodes over time in both mitigation scenarios as an increasing share of more expensive biomethane is blended into the pipeline and gas delivery charges increase for the reasons discussed above. Between 2025 and 2030, depending on wildfire mitigation costs, the monthly utility bills of mixed-fuel customers increase above those of all-electric customers in both mitigation scenarios. Of course, energy consumption and utility bills vary widely by building and climate zone, so there is a wide range of potential utility bill outcomes across the building stock in the state.

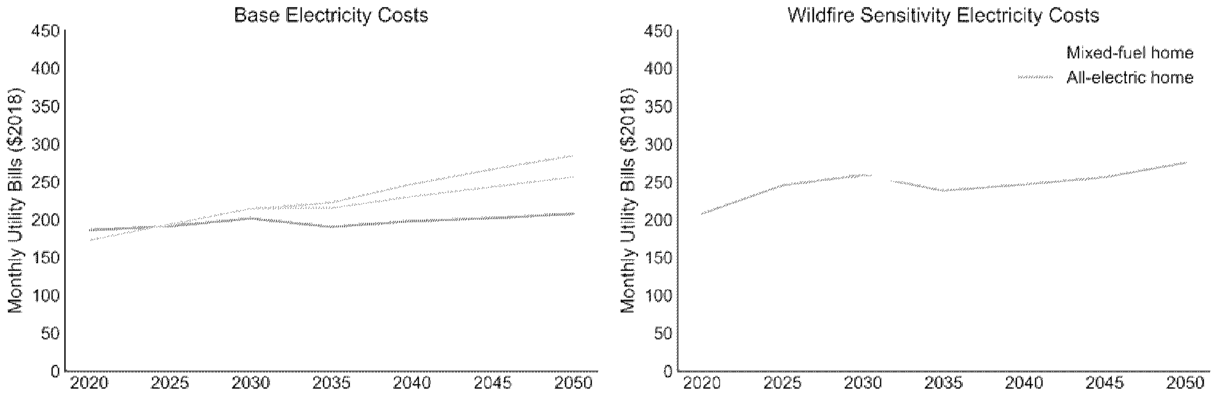
No Building Electrification

Utility bills in the no building electrification scenario increase over time because of a combination of decreased gas system throughput and an increasing share of costly electrolytic fuels that are blended into the pipeline (Figure 29). As a result, by 2040, a typical mixed-fuel customer could pay between $35 to $50 more per month than a typical all-electric customer in this scenario.

The largest impact of the wildfire cost sensitivity is to push out in time the point at which a typical all-electric home sees bill savings relative to a mixed-fuel home. In the base electricity cost case that crossover occurs in 2025, while in the wildfire sensitivity electricity costs case, that point is 2030.

Residential customers may still find cost savings from electrifying a subset of their appliances before cost savings would occur from electrifying their entire homes or businesses. For instance, this analysis finds that typical single-family residential IOU customers save from $6 to $12 per month on their utility bills in 2025 when adopting a heat pump HVAC system. Given the bill savings available, economic electrification of HVAC systems could become a particularly advantageous strategy for customers with air conditioning. Customers with air conditioning may already have the wiring, ducting, and electrical panel capacity required to install an electric heat pump with low to no retrofit costs. Heat pumps provide heating and air conditioning, allowing a single piece of equipment to replace a traditional furnace and air-conditioning unit. In fact, the cost of installing a heat pump may be less than the combined cost of the two separate pieces of HVAC equipment it replaces. That hypothesis has been supported by recent studies by E3 and others that find HVAC electrification to be economical at today's gas rates for a sizeable number of residential customers in California (Mahone et al 2018, Bilimoria et al 2019 2018, Hopkins et al 2018).

Figure 29: Consumer Bills in the No Building Electrification Scenario



Notes: The range for the mixed-fuel home depicts a range of bill impacts between the optimistic and conservative P2G commodity cost ranges. The no building electrification scenario assumes no economic electrification and reaches a pipeline blend of 44 percent RNG and 56 percent fossil NG by 2050; economic or policy-driven electrification or higher blends of RNG would increase mixed-fuel bills.

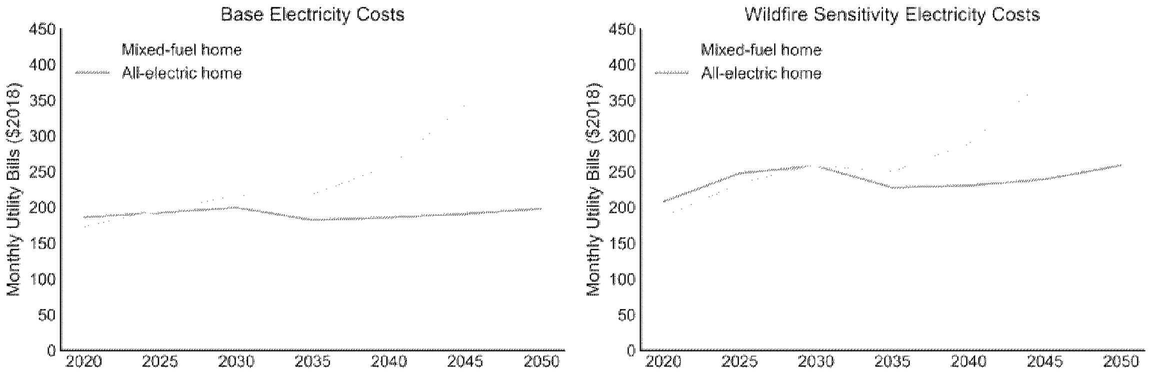
Source: E3

Each customer that electrifies some or all their heating equipment decreases the use of the gas system and increases the cost of service for remaining gas customers. As gas rates increase, the economics of electrification will improve for additional segments of residential and commercial customers. The dynamics of such a feedback loop are hard to predict because they will depend on the relative cost of pipeline gas and electricity, the relative cost of gas and electric end-use equipment and other factors ranging from consumer preferences to builder practices. For this reason, the research team did not attempt to model the potential for customer feedback effects in this analysis.

High Building Electrification

The high building electrification scenario presents gas customer challenges and points out the potential for step-changes in customer preferences and behavior based on the increasing cost of gas relative to electricity. The customer rate and bill impacts seen in that scenario would represent a cost imposition on households that continue to use gas. Those cost impacts are particularly concerning for low-income consumers who are less likely to be able to afford the upfront investments required to adopt electric technologies and are more likely to be renters.

Figure 30: Consumer Bills in the High Building Electrification Scenario



Notes: The high building electrification scenario assumes no cost savings from retirement of gas infrastructure and maintains the reference level of gas revenue requirement (excluding commodity costs) through 2050.

Source: E3

Absent policy intervention, the rate increases seen in the high building electrification scenario are unlikely to be consistent with financially stable gas utilities. Utilities raise capital from debt and equity markets on the expectation of future revenues from a customer base that is, at minimum, stable. In the high building electrification scenario, the number of gas customers in the state decreases. Those customer exits accelerate over time, leading to the rapid rate increases seen above. Those rate increases follow from the assumption that all gas system costs continue to be recovered from gas ratepayers. If that assumption does not hold, then some or all of the gap between expected customer revenues and gas utility revenue requirements will need to be filled to maintain safe operation of the remaining gas system.

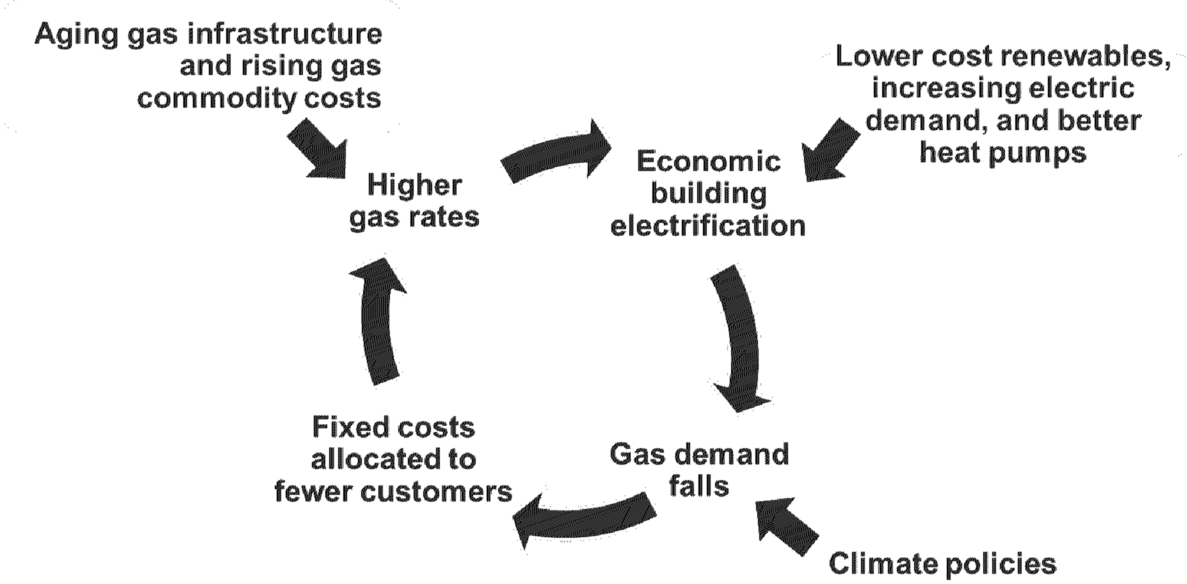
Bill Impacts Comparison and Conclusions

With those bill savings and the recent work on the economics of building electrification in mind, the research team concludes that the no building electrification scenario is unlikely to represent a stable, internally consistent future. A world in which increasing quantities of RNG are blended into the pipeline will lead to steady improvements in the economics of building electrification. So long as the state is on track to meet its climate targets, and RNG costs remain high (as estimated in this study), then building electrification appears to be the least-cost outcome from both an economy-wide perspective and from a customer-cost perspective. However, a number of potential barriers, including very high upfront capital costs for building electrification could represent a barrier to achieving this outcome. The remainder of this report will focus on the retail gas system challenges, and potential solutions, of moving toward a largely electrified building stock in California.

CHAPTER 5: Envisioning a Natural Gas Transition Strategy

California's gas system is under near- and long-term cost pressure. The costs of maintaining gas infrastructure are increasing while throughput is expected to decrease. Gas commodity costs will also increase in successful economywide mitigation scenarios, putting further upward pressure on the cost of pipeline gas. Absent intervention, these trends could drive a feedback effect that results in an unsustainable future for the gas system (Figure 31). As discussed previously, electricity costs are also expected to increase, but since electricity demand is also expected to increase, the impact on electric rates may be more muted.

Figure 31: Outside Forces Driving Change in the Natural Gas Delivery Sector Could Lead to Lower Gas Demand and Higher Gas Rates in Any Number of Future Scenarios



Source: E3

The goal of this chapter is to explore the contours of a potential gas system transition strategy for California. The potential gas transition strategies evaluated in this chapter aim to maintain reasonable gas rates for remaining gas customers, as well as the financial viability of the gas utilities, even as gas use declines in the state over the coming decades. A gas transition strategy could be designed to reduce rate impacts to all customer classes or particularly protect customers who are least able to switch away from gas, including renters and low-income residents. These scenarios were developed in recognition of the fact that, even in the high building electrification scenario, millions of gas customers remain on the gas distribution system through the entire study, albeit with reduced gas demand volumes.

In that context, maintaining reasonable gas rates becomes imperative because of the substantial equity concerns that could follow from a world in which the wealthy are more likely to be able to electrify, or to afford paying higher gas costs if they do not, but low- and middle-income households are less able to do so.

Furthermore, the operation of a safe gas system will require continued reinvestment and maintenance, even in scenarios with lower throughout. These scenarios evaluate a future in which maintaining the financial viability of gas utilities is used to ensure that these entities can continue to finance the ongoing operations and maintenance of this system. Alternative operation and maintenance structures for the gas system are conceivable, such as the creation of a state-owned enterprise. That and other legal and legislative options for a more rapid transition are outside the scope of this study.

A comprehensive gas transition strategy, informed by a myriad of interested parties, is needed. Such a strategy might include:

- Efforts to reduce barriers to electrification. It is not a straightforward process for even relatively motivated and well-resourced homeowners to install technologies like electric heat pumps. Those interested run into issues like difficulty receiving permits and contractors without heat pump installation experience. Market transformation initiatives will be needed to lower the costs and barriers to retrofits and make electrification an easy decision for homeowners.[31] There will also need to be initiatives in place to enable adoption of electric equipment for low-income homeowners and renters, particularly given the relative vulnerability of these groups to the bill impacts identified in Chapter 4.
- Avoid gas system expansion. Gas system investments come with long lifetimes. Making such investments in the context of declining throughput—an outcome that occurs in all mitigation scenarios—will increase the average cost of gas service. Unlike gas system retirements, a speculative measure at this point, building communities without gas is a common practice in large portions of the United States and world (Vivid Economics, 2017).
- Reduce costs of the existing gas system. California's gas system requires ongoing reinvestment to ensure safe, reliable service. In recent years, the magnitude of these reinvestments has increased as utilities have responded to high-profile safety incidents. A key challenge in any gas transition will be to reduce the costs of the existing gas system while still ensuring exacting standards of safety and reliability are maintained. The research team hypothesized that geographically targeted electrification and retirement of the gas system could be one potential strategy to achieve these reductions, though other measures (for example, derating of pipes to lower pressures) may also be available.
- Accelerated depreciation. Accelerated depreciation recovers investments over a shorter period than the traditional useful lifetime. When paired with reduced gas system expenditures, accelerated depreciation can further reduce the remaining costs of the gas system toward midcentury. However, accelerated depreciation will increase near-term gas rates and gas utility revenue collection. If it is not combined with a reduction in gas system expenditures and a long-term gas transition plan, accelerated depreciation may be counterproductive.

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31 Senate Bill 1477 (Stern, Chapter 378) adopted in 2018 instructs state agencies to develop market transformation programs for building decarbonization, and the CPUC has instituted rulemaking R.19-01-011 on this topic, but rules were not finalized as of this writing.

- Changes to cost allocation. The gas distribution system was built to serve building heating loads. As these loads decline, there could be justification to shift a larger share of costs to customers that continue to use the gas system. Such an approach would need to be balanced against competitiveness concerns that follow from higher rates for remaining customer classes that use the gas system (for example, industry).
- Recover gas system costs on the bills of electric ratepayers. The gas distribution system was built to serve demand from California homes and businesses. Utilities raised funds to finance that system with the expectation of a fair opportunity to recover their investments from a stable customer base. The plausibility of recovering system costs for gas customers decreases as those customers exit the gas system. It could be justifiable to collect some share of the gas system costs from customers that exit the gas system and go all-electric. The potential equity benefits of such an exit fee would need to be balanced against the potential for such a fee to discourage beneficial electrification. An alternative approach could be a competitive transition charge that is applied to the bills of all electricity customers. This approach would allow costs to be spread out more evenly over time but is less directly tied to the decision of a customer to exit and the amount of gas system costs that were incurred on his or her behalf.
- Additional funds from outside the gas system. Regulatory mechanisms to reduce and reallocate gas system costs can reduce the rate and bill impacts of a gas transition strategy. However, even under relatively aggressive assumptions about the success of those mechanisms, a substantial cost challenge remains. One option evaluated in this chapter examines the implications of infusing "additional funds" to manage remaining costs. These funds could be derived from a variety of sources (such as cap-and-trade revenues or the state general fund), though this report does not try to specify a source for such additional funds.
- Shut down uneconomic gas infrastructure built to serve building loads. In 2050, there are still 2 million residential gas customers in the high building electrification scenario. California's gas system was built to serve more than 13 million residential customers. That imbalance only worsens beyond the 2050 time horizon of this study. The high building electrification scenario assumes that the last gas appliance is sold in 2040. Given the typical lifetimes of gas equipment, this assumption means that, in a world with no early retirement of equipment, the number of gas customers in California would approach zero toward the late 2050s. The PATHWAYS model assumes relatively smooth transitions between gas and electric end uses, in part because it is so difficult to predict the timing for more abrupt changes in customer behavior or energy system choices. That said, there is likely a point between 2 million (or perhaps before) and 0 residential gas customers where customers would abruptly leave the gas system for economic reasons, even if meant early retirement of their gas equipment, and there is a point when it would no longer be viable to operate much of the state's gas distribution system. In advance of that point, without knowing exactly when that time will arrive, policy makers will need to consider what set of measures are needed to shut down unused infrastructure.

The next section evaluates each of these gas system strategies in more detail.

Gas Transition Mechanisms

Defining a complete gas transition strategy for California is beyond the scope of this or any study. Instead, this analysis is meant to examine plausible impacts of a subset of the policy and regulatory mechanisms that could fall within a broader transition plan. The mechanisms examined target two key goals:

1. Reduce the cost of the gas system while ensuring reinvestment to ensure safety and reliability
2. Equitably allocate the fixed costs of the gas system

Reduce the Costs of the Gas System

A fundamental challenge facing California's gas system is that costs are expected to increase, and throughput is expected to decrease. Chapter 4 outlined the adverse consumer effects of this phenomenon assuming gas-system costs were equal to the reference scenario and were collected entirely through rates. Those results are meant to highlight the scale of the cost challenge facing the California gas system and associated customers. Given those challenges, California's energy policy and business community will need to consider strategies to reduce the cost of the gas system.

A key premise of this analysis is that California's gas system requires reinvestment to ensure safety. Any strategy to reduce costs will need to be implemented with that imperative in mind. Such reductions might be possible via a variety of mechanisms, including:

- Halting expansion of the gas system. Gas infrastructure is long-lived, with a typical distribution main having a book life of between 50 and 65 years (PG&E 2018, SCG 2019). Adding new infrastructure increases the size of the gas system financial obligation California will face in the future. Insofar as throughput declines and customer exits can be expected, these additional obligations will increase the cost of gas service for remaining gas customers, with all the potential negative consumer equity implications outlined in Chapter 4. Avoiding new infrastructure could help slow the growth of future financial obligations without incurring any risk of declines in system safety or reliability.
- Targeted retirement of the gas distribution system. California's gas utilities spend nearly $3.5 billion per year in operations and maintenance to ensure safe and reliable gas service. That ongoing O&M expense is in addition to capital reinvestments to replace aging infrastructure. A potential response to these expenditures could be to reduce the overall footprint of the state's gas distribution system. Doing so would reduce the need to reinvest in, and potentially reduce the O&M costs associated with, aging infrastructure. However, this strategy is somewhat speculative, hinging on successful identification of geographies that are ripe for retirement and successful targeting of electrification efforts. That overlay is particularly important because early retirements of utility infrastructure and consumer end-use equipment carries real economic costs.
- Derating of infrastructure to reduce reinvestment and O&M costs. It may be possible to reduce the cost of maintaining existing gas infrastructure if, for instance, certain segments of the gas system could be operated at lower pressures.

There are not sufficient data available at this time to allow precise modeling of each of these mechanisms. Instead, this study models scenarios that stipulate a decrease in gas system capital reinvestment and annual O&M. These scenarios are defined by two key parameters.

1. Percentage reduction in annual capital expenditures. This analysis models the amount of capital that needs to be reinvested as the previous year's depreciation, grossed-up by a real capital escalation factor of 1 percent per year. The exact percentage chosen can be thought of as capturing either how sensitive capital expenditures are to system utilization or how successfully a targeted gas distribution program has been implemented.
2. The year in capital reinvestments that can start being reduced: This figure represents how quickly a targeted electrification/targeted retirement program can be ramped up. This study assumes that such a program would need to achieve enough gas disconnections to avoid substantial early equipment retirement costs.

Using those parameters, the research team defined three gas system cost reduction scenarios (Table 4). These scenarios are meant to illustrate the effects of reduced gas system expenditures. These cases are compared against a "no action" scenario where the state's gas revenue requirement is equal to the Reference scenario forecast.

Table 4: Gas Cost Reduction Scenarios

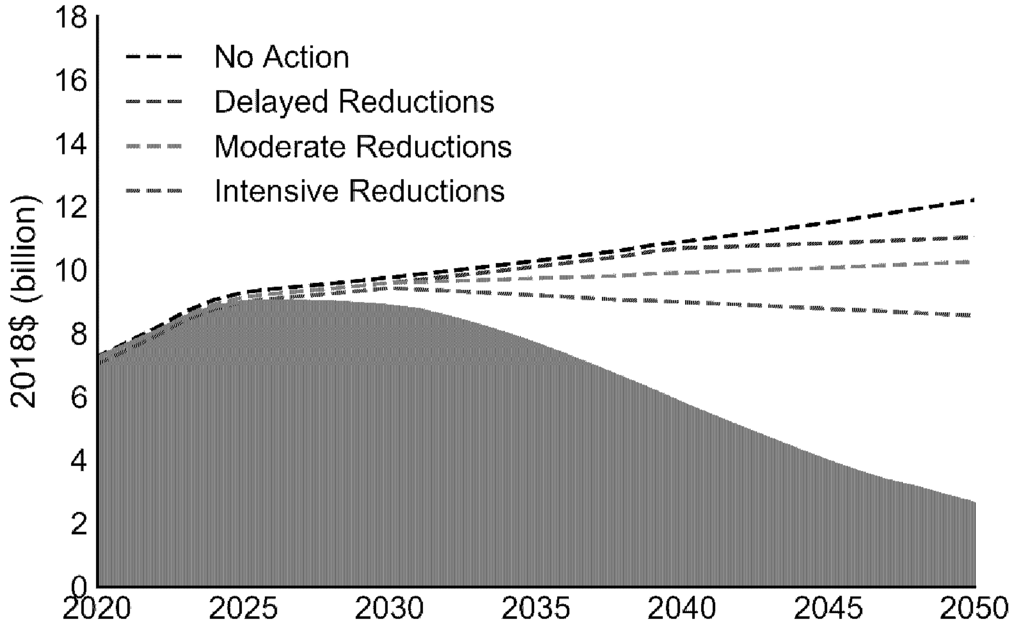
Retirement Scenario Name	Year Reinvestments Are Decreased	% Reinvestment Avoided
Intensive Reductions	2030	50%
Moderate Reductions	2030	25%
Delayed Reductions	2040	50%

Source: E3

Figure 32 shows California's gas revenue requirement in each of these scenarios.

Strikingly, even the most ambitious revenue requirement reduction scenario modeled, the "intensive retirements" scenario, does not reduce the state's gas system revenue requirement below that of the current value. This result occurs for two reasons. First, as discussed in Chapter 4, the state's gas system revenue requirement is expected see a marked near-term increase as utilities continue their safety-related upgrades to the state's gas system. By 2025, these investments increase the state's revenue requirement by more than one-third. The second reason is real escalation of gas capital costs. This study assumes, based on historical indices of gas capital costs, 1 percent real escalation of capital and operations and maintenance costs. The compounding effect of this real cost escalation puts upward pressure on the reinvestment costs of the gas system. Some of the growth assumed within that escalation rate could be offset by avoiding expansion of the gas system.

Figure 32: Gas Cost Reduction Scenarios



Source: E3

The cost reduction scenarios modeled in this analysis are meant to represent a set of plausible futures where the gas system revenue requirement can be reduced below the no action baseline. Exactly what magnitude of cost decreases are achievable in practice is not yet known. However, what this analysis does indicate is that even a very aggressive set of cost-reduction measures can probably only mute—and certainly cannot eliminate—the cost and equity challenges facing the state's gas system. Further measures are needed to ensure energy affordability and equity.

Equitably Allocate the Costs of the Gas System

The cost challenges facing the gas system result from declining throughput and customer exits. The customer rates and residential bill impacts results presented above reflect a world where gas system costs are allocated similarly to today. That means residential customers continue to pay for the bulk of the gas distribution system, depreciation schedules follow current assessments of the useful life of assets, and the gas revenue requirement is recovered entirely via rates. However, current methods of allocating gas system costs were designed for a world in which gas demand was expanding in California. Current cost allocation methods may not be appropriate in a world with rapidly decreasing gas demand.

Cost allocation changes could take different forms. Within the gas regulatory context, costs could be shifted from customers that no longer use that system (that is, residential) to customers that continue to use the system (that is, industrial). It could also be advisable to shift costs within customer classes over time. For instance, accelerated depreciation could allow long-term obligations to be paid for when a larger share of customers continue to receive gas service. Finally, costs could be shifted outside the gas system. Such a shift could be based on achieving procedural fairness and equitable outcomes. This section examines several mechanisms to reallocate remaining gas system costs.

Shift Cost Allocation Between Customer Classes

Today, gas delivery in California is allocated to customers based on their utilization of the system. "Utilization" can be defined in a variety of ways but typically includes total annual consumption and peak demands.[32] For this analysis, researchers assumed that transmission costs are allocated to customers based on their share of annual throughput, while distribution costs are allocated based on the existing share of revenue each customer class pays to that part of the system. In practice, distribution costs are allocated based on peak demands, using either a peak-day or peak-month method.

A key challenge with cost recovery in a future with high building electrification is that throughput falls most rapidly in the gas distribution system. Further, those throughput reductions occur in roughly equal proportion between the two primary users of the distribution system, residential and commercial buildings. These reductions lead to rapidly increasing costs for remaining gas distribution customers. A potential solution could be to allocate distribution costs to a broader set of gas system customers. This analysis models changes in gas cost allocation as a percentage shift from current allocations of distribution costs toward a system throughput-based allocation. To illustrate the effect of this cost reduction, it further models a scenario where the percentage of distribution costs that are allocated based on throughput increase from 0 to 40 percent in 2050. Such a shift could reflect a different allocation of peak-day or peak-month loads by customer classes.

Accelerated Depreciation

Accelerated depreciation shortens the period over which capital investments are recovered. For instance, a utility asset with a baseline depreciation schedule of 20 years could instead be collected over 10 years. In practice, this collection schedule would effectively double the annual depreciation charge for that asset. This approach could be justified for two key reasons. The first is that, as a matter of principle, depreciation schedules are meant to reflect the useful life of an asset (Bilich et al 2018). In current practice, the useful lives of assets are typically assessed based on a likely survivor curve derived from historical experience. In the future, an empirical survivor curve is a less accurate predictor of useful life than expected utilization over time. If utilization is expected to decrease such that the asset is no longer used, then the associated useful life could plausibly be considered shortened. A second reason to consider accelerated deprecation is that it would effectively allow the fixed costs of the gas system to be collected over a larger group of ratepayers. Accelerated depreciation would shift fixed-cost recovery to periods before large-scale electrification and customer exits from the gas system occur (Figure 33).

Exit Fees

The gas system was built with the expectation of a stable long-term customer base. Customers that leave the gas system no longer contribute toward the fixed costs of infrastructure that was built on their behalf. As shown above, this situation shifts those fixed costs to remaining gas customers, with the associated rate bill effects and equity concerns. A potential measure to address this issue could be to charge customers that leave the gas

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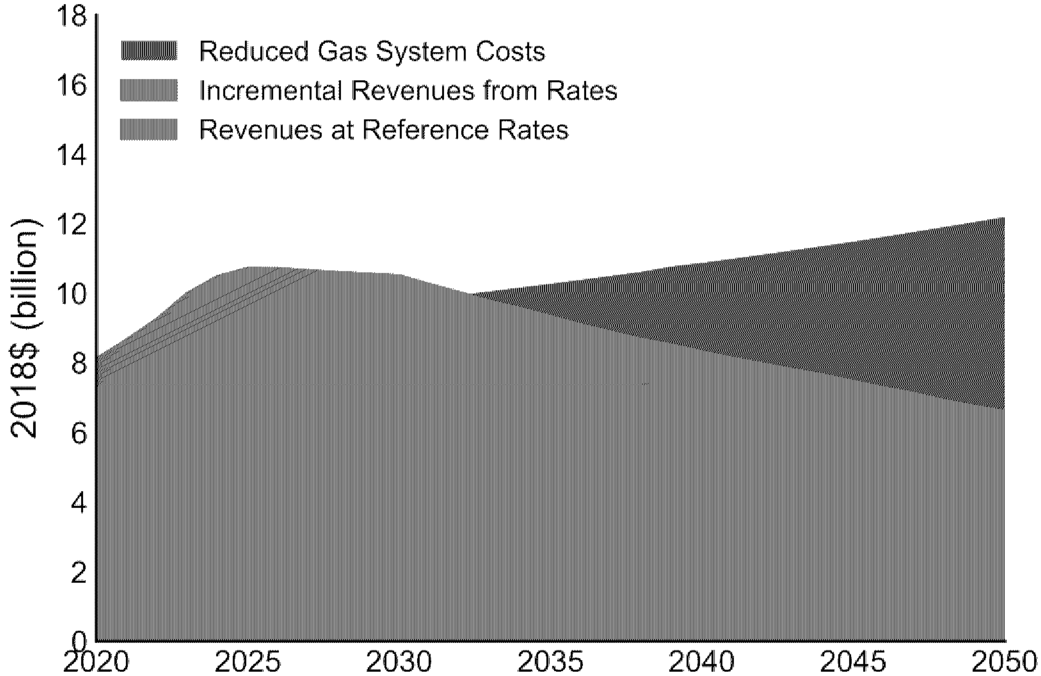
32 Peak demands are assessed based on daily and monthly consumption in the distribution system (SCG TCAP 2019).

system an exit fee. Such an exit fee could be collected either as a lump sum or amortized over a longer time frame. This study assumes the latter approach because it avoids adding a substantial upfront incremental cost that could slow otherwise beneficial electrification. This approach is modeled as a $5-per-month exit fee applied over a 15-year period, collecting a total of $900 per exiting customer (Figure 34).

Figure 33: Revenue Requirement With Intensive Reductions and Accelerated Depreciation



Notes: The red wedge shows the cost savings associated with gas system cost reductions and accelerated depreciation. The blue wedge shows incremental revenue collected through gas rates. The blue wedge increases revenues substantially in the near term, but doing so enables deeper cost savings in the future than can be achieved by reduced reinvestment alone.

Source: E3

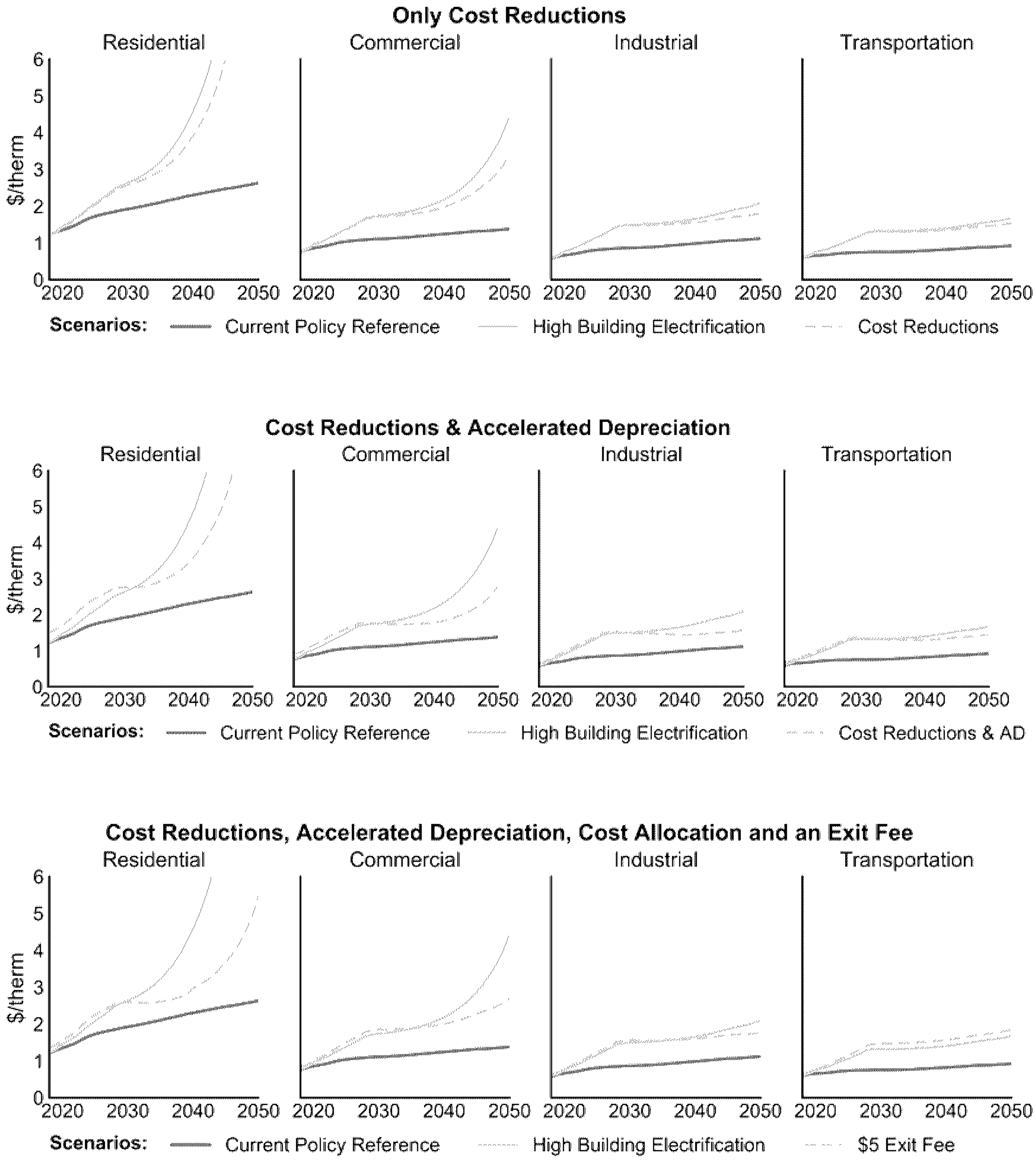
Other Funds

Given the magnitude of gas system cost recovery challenges, there may be good reason to commit funds from elsewhere in the economy to reduce the cost stresses on the gas system and related customers. Potential sources of these funds include the state's general fund cap-and-trade revenues, a transition charge on the bills of all electric ratepayers, or decreased returns for utility shareholders. This analysis treats these types of measures as a source of "additional funds" without attempting to attribute a specific source. Instead, the research team aims to explore what magnitude of additional funds are required after other strategies are exhausted.

Effect of Gas Transition Mechanisms on Rates

Figure 34 shows the effects of gas transition mechanisms on the rates paid by residential, commercial, industrial, and transportation customer rates. The first row shows the rates that would follow from the "Intensive Cost Reductions" scenario described above. Reducing gas system costs does reduce rates somewhat, but rates continue to escalate rapidly for residential and commercial customers. The next row layers accelerated deprecation onto retirements. This layering leads to increased customer costs in the near term but lower rates in later periods. The final row adds a shift in cost allocation and a $5-per-month exit fee. This scenario markedly reduces residential and commercial customer rates but still leaves costs that are likely untenable for low- and middle-income Californians.

Figure 34: Natural Gas Rates With Gas Transition Mechanisms



Source: E3

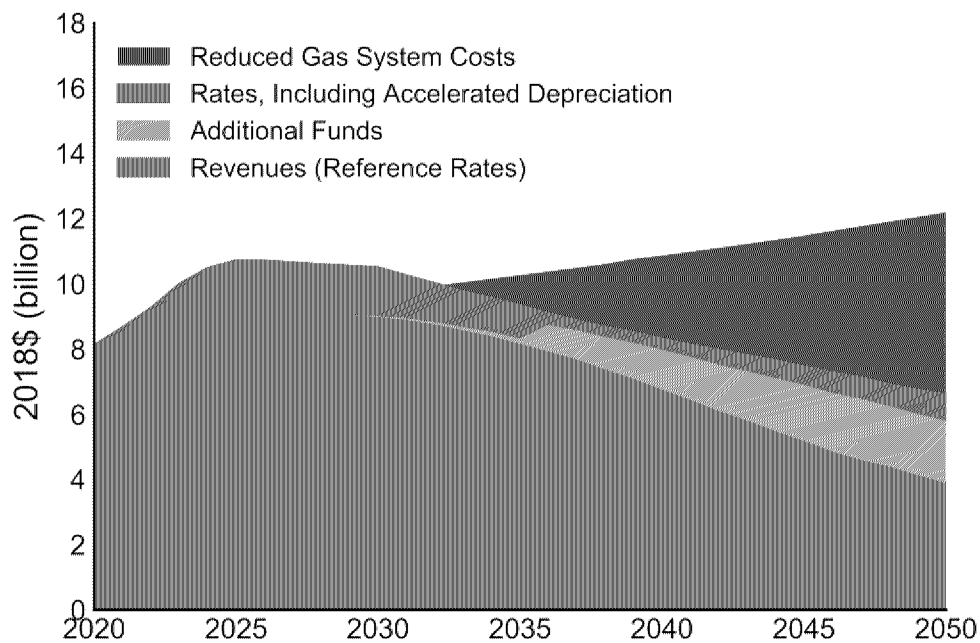
Example Gas Transition Strategy

This section offers an example gas transition strategy that uses a combination of the mechanisms described above. The strategy aims to manage the rate effects of decreasing gas throughput for all customer classes, with an aim of reducing the financial impacts of the transition on the most vulnerable Californians. The research team is not recommending any strategies here but rather illustrating what a systematic treatment of this issue could entail. The example gas transition strategy includes the following assumptions:

- Gas system cost reductions: Following the intensive cost reductions case, this strategy assumes a 50 percent reduction in capital reinvestment and associated operations and maintenance expenses.
- Accelerated depreciation of gas system capital: This strategy shortens the depreciation schedule of all existing and new capital to half that used today.
- Shift gas customer cost allocation: This strategy assumes that by 2050, 40 percent of distribution costs are allocated based on total system throughput.
- Gas customer exit fee: A $5-per-month would be collected for 15 months on exiting customers' electric bills.
- Additional funds: Starting in 2035, additional nonratepayer funds are used to cover a share of the gas system revenue requirement. The amount of additional funds rises to $2 billion per year in 2050.

Figure 35 shows the effect of the gas transition strategy on California's gas system revenue requirement.

Figure 35: Revenue Requirement With Gas Transition Strategy



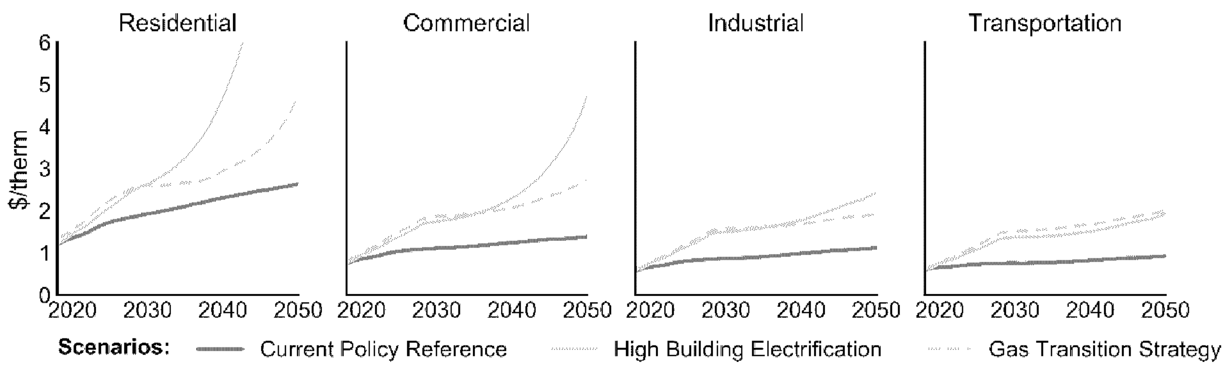
The orange wedge represents additional unspecified "additional funds" that are used to reduce bill impacts on remaining gas customers

Source: E3

The state sees a more rapid near-term increase in its gas revenue requirement due to accelerated depreciation (depicted in blue). However, the additional near-term expense allows deeper gas system cost reductions in later years (depicted in red). While incurring more near-term costs may not be preferable from a time value of money perspective, the cost reduction achieved in later years eases the challenge of achieving an equitable gas system transition. This example still requires a substantial infusion of "additional funds" of $11 billion in net-present value terms (depicted in orange).

Compared to the base high building electrification scenario, the example gas transition strategy in Figure 37 reduces rates for all customers except those in the transportation sector, whose gas rates are little affected by these changes. Residential customers see the largest decreases in rates relative to the base case because of reduced distribution system costs and a shift toward throughput-based cost allocation.

Figure 36: Customer Rates After a Gas Transition Strategy in the HBE Scenario



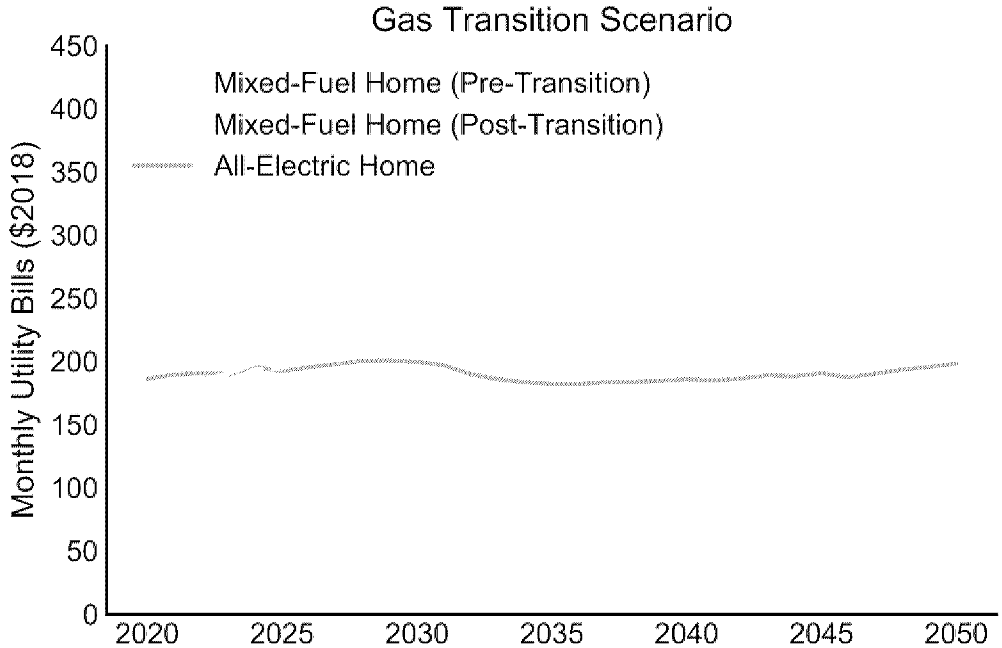
Source: E3

Residential customers also see large bill savings as a result of the example gas transition strategy. In the base case, those customers' bills increase to more than $600 per month, an amount that is cut by more than half after the example gas transition strategy (Figure 37). Mixed-fuel customer bills are slightly higher in the near term due to the additional accelerated depreciation expense, but those costs are relatively small on a per-capita basis compared to the savings achieved further out in the study period.

Sensitivity of Results to Early Retirements

The example gas transition strategy reduces the cost of the gas system by $4 billion annually in 2050 and $25 billion cumulatively in net-present value terms. However, gas system infrastructure retirements may not be achievable without early replacement of consumer end-use equipment. There are two real economic costs that stem from replacement of equipment. The first is that the equipment has remaining useful life. The second is the opportunity cost of purchasing a new appliance earlier than a consumer would have otherwise. All else being equal, these costs are tied to the average lifetimes of equipment that are retired. Post-2040, no new gas equipment is sold in California in the high building electrification scenario, so the age of remaining equipment increases after that year, and the cost of early retirement decreases.[33] Though not modelled in this analysis, it would be the case that by the mid- to late-2050s early retirement costs in the high building electrification scenario would approach zero.

Figure 37: Residential Bills Before and After the Example Gas Transition Scenario



Source: E3

This study tests two early retirement sensitivities: one where 20 percent of building equipment is retired early over the study period and one where 10 percent of building equipment is retired early. The sensitivities assume that the oldest equipment is retired first and economic costs include the two categories mentioned above. These percentages are meant to reflect a successful, though not perfect, targeted electrification program that replaces most appliances on burnout. Table 5 summarizes the NPV costs of each sensitivity.

Table 5: Cost of Early Retirement Sensitivities

Early Retirement Sensitivity	**Incremental NPV Cost**
10% Early Retirement	$4 billion to $6 billion
20% Early Retirement	$8 billion to $12 billion

Source: E3

These sensitivities illustrate the potential trade-offs between reducing gas system expenditures and the costs associated with achieving those retirements. If gas system cost reductions require large-scale early retirements of gas equipment, then those cost savings may be somewhat eroded.

33 Assuming an average equipment lifetime of roughly 15 years for gas furnaces, the early retirement costs in the high building electrification scenario approach $0 in the mid-2050s.

CHAPTER 6: Conclusions

Achieving California's climate policy goals requires transformational changes across all sectors of the state's energy economy. This study focuses on the role of the state's gas infrastructure, particularly the low-pressure, retail gas distribution system, examining different scenarios for how gas use will change in California. A key finding is that gas use decreases in all scenarios that meet an 80 percent reduction below 1990 emissions by 2050 target. Common drivers of that throughput decline across scenarios are steep reductions in gas use in electric generation and energy efficiency in industry and buildings. The key source of throughput variation in scenarios developed in this study is the amount of electrification in buildings. Scenarios with more building electrification lead to lower overall retail gas demand, with especially sharp declines in buildings. The level of gas demand, in turn, has profound implications for the overall amount and distribution of costs related to achieving California's climate policy objectives.

Scenarios with more gas demand require a combination of more mitigation elsewhere in the economy and higher levels of RNG. Relying on mitigation elsewhere in the economy means that more energy-intensive sectors of the California economy, like heavy-duty trucking and industry, would need to carry a greater share of the GHG reduction load. If those challenging mitigation measures do not prove workable, then the remaining strategy to achieve the 80 percent by 2050 reduction is to increase the share of RNG in the pipeline.

Another key finding of this study is that relatively inexpensive RNG (for example, biomethane from landfills and wastes) is limited and cannot alone reduce the GHG intensity of pipeline gas enough to achieve 80 percent reduction. Once the biomethane portion of the RNG supply curve is exhausted, then the state must turn to more expensive hydrogen and yet more expensive SNG. The result is that by 2050, the commodity cost of blended pipeline gas is more than four to seven times that of natural gas today. This premium leads to large increases in rates and total costs for all customers that use pipeline gas today. Importantly, the no building electrification scenario leaves 56 percent of the pipeline as natural gas. If more pipeline decarbonization were needed—as may be the case in a carbon-neutral scenario—the cost of the marginal RNG resource, SNG with DAC, would be between 10 and 22 times that of natural gas today. Indeed, the level of costs seen in the no building electrification scenario suggest that there will be some level of economic electrification based on price alone.

A conclusion of this analysis is that scenarios with more building electrification have lower total societal costs. However, these scenarios raise challenging issues related to the cost of maintaining the state's retail gas distribution infrastructure in the context of lower utilization. If throughput declines and gas system costs do not, then large financial obligations will be left to be paid by a smaller number of customers. In the later years of the study period, this situation leads to rapidly increasing gas customer bills and rates. These rates and bills are unlikely to be consistent with an economically sustainable gas system. Particularly concerning is the prospect that low- and moderate-income Californians or renters, who may be unable to electrify due to upfront costs or lack of home ownership, could bear the impact of these cost increases.

Another consideration around building electrification pertains to risk and uncertainty. The choices facing California regarding building decarbonization present asymmetric risks, particularly because of the time required to transform building infrastructure and the urgency of addressing climate change. The main barriers to building electrification are upfront capital cost and consumer acceptance. However, once these costs are paid and consumers gain familiarity with electric appliances, even if inexpensive sources of RNG become available later, the state's climate goals will still be met, and residents will be able to heat their homes relatively affordably. In contrast, should building electrification be delayed in the hope that RNG technology will progress more rapidly than considered in the optimistic P2G cost scenario here, and these RNG cost reductions do not materialize, then it will be difficult to recover from delays in building electrification and it may prove difficult to reduce emissions at reasonable cost. Further, customers who do not electrify face the risks associated with high cost of gas, while customers who electrify, do not face the same level of rate impact risk.

The results of the two bookend scenarios indicate that California should begin investigating a natural gas system transition strategy. A gas transition strategy could have several goals, ranging from cost reductions to protection of gas utility workers. This study focuses on components of a gas transition strategy that relate to reducing total system costs and the bill impacts for remaining gas customers. Results from this analysis suggest that there is no silver bullet strategy to manage these challenges. Instead, a suite of measures will need to be considered, including reductions in gas system costs, accelerated depreciation, changes to cost allocation, and infusion of electric- or non-ratepayer funds. The gas distribution system continues to be used throughout the study period in these scenarios, so such a strategy will need to be developed without compromising the safety and reliability of the remaining system.

This study also sets out the contours of an ongoing research agenda for California. A clear finding of this study is that RNG, particularly biomethane, is used in all mitigation scenarios that achieve an 80 percent reduction by 2050. Electrolytic fuels appear to have more limited roles in an 80 percent reduction policy regime but may have larger roles in achieving the state's 2045 carbon-neutrality target, particularly in sectors of the economy that are otherwise difficult to decarbonize. Research by UCI suggests that there is a wide range of potential cost trajectories for those technologies, so further consideration of how to achieve costs consistent with the "optimistic" P2G scenario of this study is warranted. Identifying the role of these zero-GHG gaseous fuels—both on their own merits and in comparison to alternatives—in providing resiliency benefits to the state of California was beyond the scope of this study and is a topic that may warrant further investigation, as are questions around the possibility of exceeding the 7% hydrogen blend limit in the gas system.

Another area deserving of further research relates to the development of the gas transition strategy itself. Many important next steps are recommended for additional research in the arenas of policy questions, engineering questions, and legal and regulatory questions. Key policy questions include the following:

- How should the benefits and costs of a gas transition strategy be allocated among stakeholders?
- How can California protect low-income residents, and gas workers, during a gas transition?

Key engineering questions around gas pipeline safety and costs include:

- To what degree can targeted electrification efforts safely reduce gas distribution expenditures? To answer this question, more data are needed to understand the geographic details of the gas system in California, as well as the replacement schedules for the existing gas system.
- What is the cost of targeted electrification, considering the potential for early retirements of consumer equipment? A better understanding is needed of the real-world technical and economic options to reduce gas system expenditures. Pilots and real-world research could help understand the costs and options to launch targeted electrification in communities in such a way that would enable targeted retirements of the gas distribution system and would consider the impacts on the electric distribution system of targeted electrification, along with the potential for cost savings on the gas distribution system.

More research is needed to identify the legal and regulatory barriers to implementing a gas transition strategy, along with targeted electrification programs. For example:

- Should natural gas companies be able to collect the entire book value of their assets? Should shareholder return be affected in a gas transition strategy? How does the timing of a gas transition strategy affect the answer to these questions?
- Should California gas utilities' obligation to serve be redefined?

Finally, this study does not include an in-depth investigation of the role of the high-pressure gas system to deliver decarbonized fuels in the context of achieving California's 2045 carbon neutrality goal. This study, done in the context of an 80 by 50 target, assumes that unabated natural gas continues to serve industrial and electric generator loads. In a carbon neutral future, zero-GHG gaseous fuels may play a larger role in those sectors.

This research paper does not seek to make policy recommendations, but rather highlight key issues for further policy debate and illuminate some implications of meeting the state's climate goals. With foresight and coordination, Californians can plan for an equitable, low-carbon future.

LIST OF ACRONYMS

Term	Definition
AAEE	Additional achievable energy efficiency
AEC	Alkaline electrolytic cells
APEP	Advanced Power and Energy Program
CARB	California Air Resources Board
BEV	Battery-electric vehicle
CCS	Carbon capture and storage
CEC	California Energy Commission
CFC	Chlorofluorocarbons
CNG	Compressed natural gas
CPUC	California Public Utilities Commission
CO_2	Carbon dioxide
DAC	Direct air capture
E3	Energy and Environmental Economics, Inc.
EE	Energy efficiency
EJ	Exajoule, a unit of energy equal to one quintillion (10^{18}) joules
EPIC	Electric Program Investment Charge
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
F-gas	Fluorinated gas
GGE	Gallons of gasoline equivalent
GHG	Greenhouse gas
GRC	General rate case
GWh	Gigawatt-hour, a unit of energy in electricity
GWP	Global Warming Potential
H_2	Hydrogen
HBE	High building electrification scenario
HDV	Heavy-duty vehicles
HFC	Hydrofluorocarbons

Term	**Definition**
HHV	Higher heating value
HVAC	Heating, ventilation, and air conditioning
IOU	Investor-owned utility
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicles
LHV	Lower heating value
MDV	Medium-duty vehicles
MW	Megawatt, a million watts, a unit of capacity in electricity
NBE	No building electrification scenario
PCC	Postcombustion capture
PEMECs	Proton exchange membrane electrolytic cells
P2G	Power to gas
PHEV	Plug-in hybrid electric vehicle
PJ	Petajoule, a unit of energy equal to one quadrillion (10^{15}) joules
PM	Particulate matter
NOx	Oxides of nitrogen
RNG	Renewable natural gas
RR	Revenue requirement
RPS	Renewables Portfolio Standard
SB	Senate Bill
SLCP	Short-lived climate pollutant
SOEC	Solid oxide electrolytic cells
SNG	Synthetic natural gas
TRC	Total resource cost
TRL	Technology readiness level
TW	Terawatt is a trillion watts (10^{12}), or a million megawatts
TWh	Terawatt is a trillion watt-hours (10^{12}), or a million megawatt-hours
UCI	University of California, Irvine
VMT	Vehicle miles traveled
ZEV	Zero-emission vehicle

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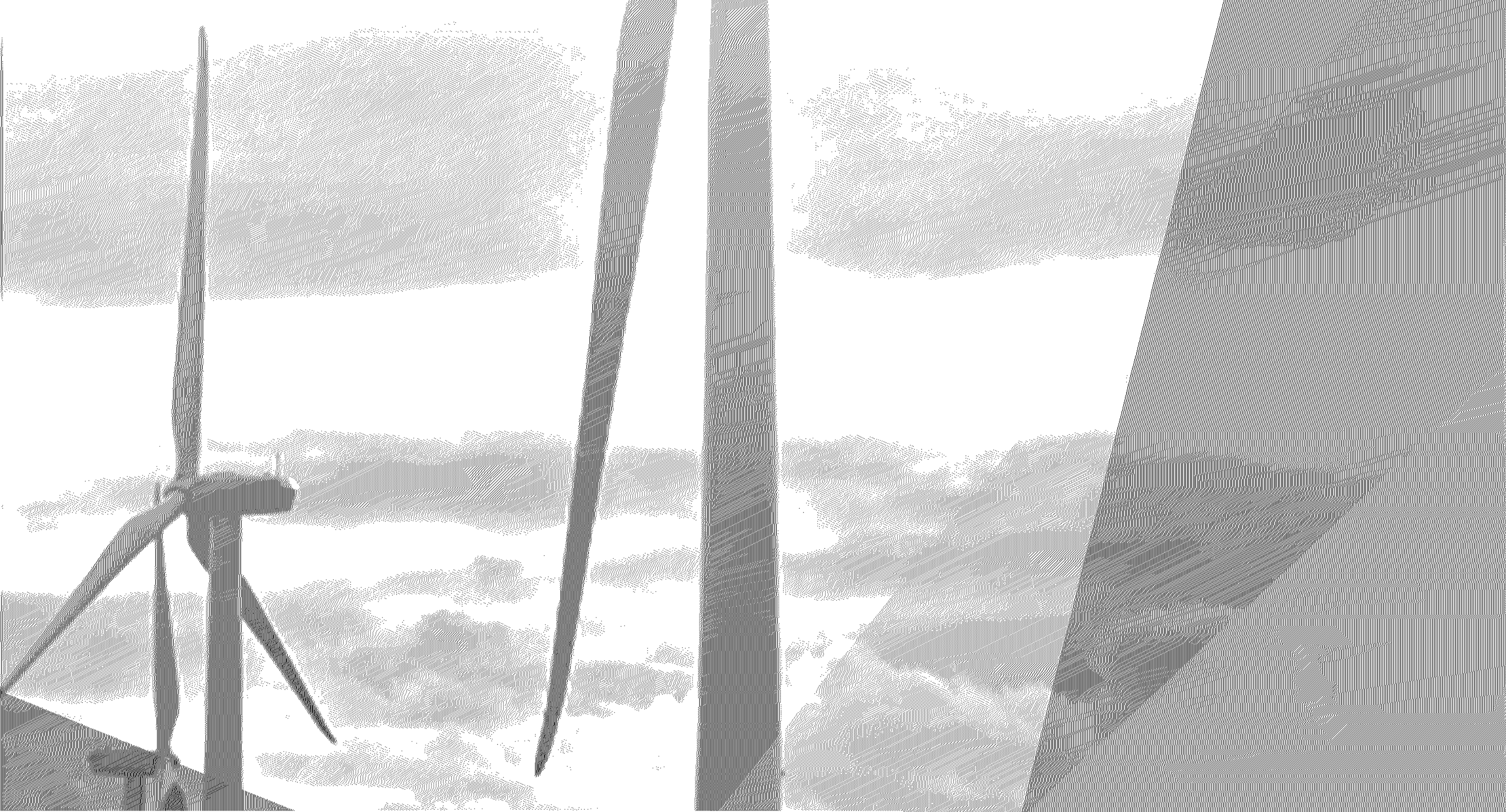
ATTACHMENT 2
Conservation Advocates Comments

Energy Pathways to Deep Decarbonization

A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study

December 2020



Executive Office of Energy and Environmental Affairs

Massachusetts Global Warming Solutions

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This report was prepared by Evolved Energy Research for the Commonwealth of Massachusetts as part of the Decarbonization Roadmap Study.

Evolved Energy Research
Ryan Jones
Ben Haley
Jim Williams (University of San Francisco)
Jamil Farbes
Gabe Kwok
Jeremy Hargreaves

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1 Executive summary

In January 2020, during his annual State of the Commonwealth address, Governor Charlie Baker committed Massachusetts to an aggressive target of net-zero greenhouse gas emissions by 2050. Following the Governor's commitment, in April 2020 Energy and Environment Affairs Secretary Kathleen Theoharides formally established Net Zero as the Commonwealth's new legal limit for greenhouse gas emissions for 2050. This report focuses on the largest single component of these emissions, carbon dioxide (CO_2) from energy use, and how it can be dramatically reduced or eliminated while maintaining a vibrant economy in the Commonwealth. The report is based on a detailed modeling analysis of eight potential pathways, or technology strategies, that the Commonwealth could follow to reach its Net Zero target. The analysis compares and contrasts these pathways in order to highlight both the common elements across different approaches to transforming the energy system, and the relative costs and tradeoffs between them. It includes in-depth analysis of topics such as regional electricity planning and operations, including offshore wind and transmission; the use of electricity versus decarbonized gas in buildings; and the use of distributed versus central station solar photovoltaic (PV). It raises topics that are seldom discussed at present but will be important in a decarbonized system, such as cross-sector coupling between electricity, transportation, and bioenergy. The research was carried out using the latest available modeling tools and data and is meant to provide both broad results and detailed analysis for a technical audience. This report was developed under the auspices of the Massachusetts Executive Office of Energy and Environmental Affairs (EEA), which has been charged with mapping out strategies to reach the Net Zero target. Subsequent EEA reports will cover other aspects of the Net Zero challenge and will also provide an overall synthesis and policy recommendations.

This is a technical report and does not make policy recommendations or determine the preferred pathway for Massachusetts. However, it does provide significant relevant information, both quantitative and qualitative, about costs, benefits, risks, and tradeoffs among the different strategies that should be taken into consideration when making policy decisions. It also identifies areas where more information will be needed before major policy choices are made and suggests specific research topics and potential pilot projects that could help provide this information. The origins and applications of long-term energy planning studies ("pathways studies") of this kind are discussed in Section 2.3, and the uncertainties and limitations inherent in such exercises are discussed in Section 3.3. Limitations notwithstanding, a number of important and robust findings have emerged from this study, which are highlighted in this Executive Summary.

1.1 Main Findings

Following a detailed analysis, this report finds that energy system transformation consistent with Massachusetts' Net Zero limit is feasible and that there are multiple pathways to reach the target. All pathways involve some tradeoffs that will need to be carefully considered, and all will require decades of sustained collective action. That said, there are four main energy-sector transformation strategies common to all net-zero pathways:

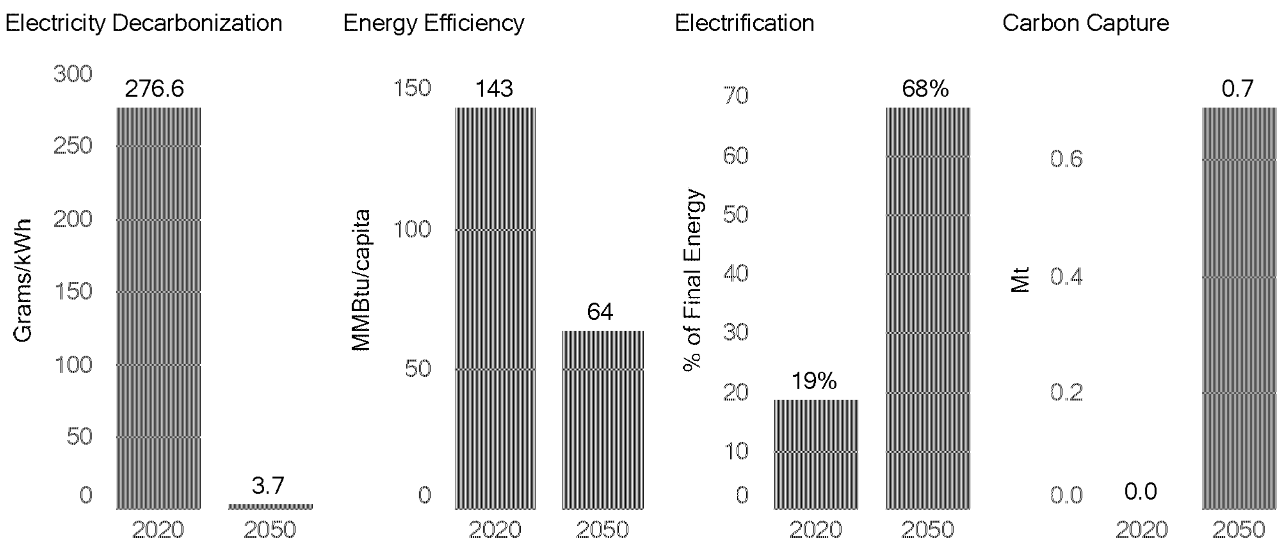
- **Increasing energy efficiency** – Increasing the efficiency of energy use across the economy significantly reduces costs while also reducing the scale of infrastructure additions required for deep decarbonization.
- **Electrifying end-use technologies** – Electricity is the least-cost means of supplying zero-carbon energy, and in many cases, electrification also increases energy efficiency. The greater the efficiency benefits,

and the more flexible the end-uses in terms of their time of use, the more competitive electrification is relative to using decarbonized fuels.

- **Decarbonizing electricity** – As the main form of energy consumed, electricity is the foundation of a decarbonized energy system. For total energy system emissions to reach the target, the carbon intensity of electricity must reach nearly zero.
- **Using carbon capture technology** – Not all end uses can or will be electrified, therefore some fuels are required. Carbon capture is an integral part of managing fuel use in a net-zero energy system, applied to the production of net-zero fuels and/or to capturing emissions from fuel combustion.[1]

These basic strategies— "the pillars of decarbonization"— have been identified in previous pathways studies, in the U.S. and internationally. The key metrics for each pillar in Massachusetts are shown in Figure ES1, which contrasts the Net Zero system in 2050 to today's system.

Figure ES1. Four pillars of decarbonization for the All Options pathway. Key metrics include a 98%+ reduction in the carbon intensity of electricity production, a 55% reduction in per capita energy consumption, a 3.5x increase in the share of final energy delivered by electricity, and captured carbon within Massachusetts of 0.7 MMt.



The modeling included a number of assumptions that increase the realism and comparability of these results. No behavior change was assumed that would decrease the demand for "energy services" such as driving, flying, heating, and manufacturing. Consequently, these results demonstrate that the Net Zero target was achievable even while meeting the latest U.S. government projections of long-term energy service demand. All technologies used are either already commercially available or have been demonstrated at a large pilot scale. There was no early retirement of end use equipment before the end of its economic lifetime. Finally, a number

[1] Carbon capture is a pillar of decarbonization that is applied in all pathways, including the 100% primary renewable energy pathway in which captured carbon is needed for producing renewable fuels. However, carbon capture and storage (CCS), in which the captured carbon is geologically sequestered, is not; CCS is used in only one pathway, in which the sequestration occurs out-of-state. Most carbon capture opportunities are also outside Massachusetts, in states better suited for the production of net-zero fuels; in theory all carbon capture could occur out-of-state. However, since carbon capture is essential to a net-zero energy system regardless of physical location, it is included here as a pillar of decarbonization. In these pathways, bio-asphalt is a form of carbon sequestration employed in Massachusetts, but it does not involve carbon capture.

of environmental constraints were imposed, including limits on biomass supplies, land for siting renewable energy, and geologic sequestration of CO_2.

1.2 Decarbonization Pathways

The eight decarbonization pathways were designed to inform Massachusetts policymakers about the effects of key strategic decisions and uncertainties it faces in developing policies to achieve net-zero emissions. The design framework is a scenario approach frequently used in energy planning, in which key assumptions or input values are changed one at a time. Table ES1 shows the key characteristics of each pathway relative to the All Options case, which served as the baseline from which the other pathways were developed and to which their results were compared. For other pathways, assumptions about either the cost or available technology options were changed. Section 4 in the main text provides detailed descriptions of the rationale and input values for each pathway.

Table ES1. Summary of pathways analyzed

Pathways Analyzed	*Key Characteristics / Distinguishing Features*	
All Options	**Baseline analysis –** model selecting most economic resources to meet emissions limits using baseline cost assumptions.	Least Cost
DER Breakthrough	High deployment of behind-the-meter solar + flexible loads	Least Cost
Regional Expansion	Lower-cost electric transmission + export of captured CO2	Least Cost
OSW Constrained	Region constrained to 30 GW offshore wind at higher cost. Economic expansion of nuclear allowed.	Least Cost
Pipeline Gas	Low-electrification of pipeline gas uses in buildings and industry.	
Limited Energy Efficiency	Buildings, industry, & transport remain at reference efficiency.	
100% Renewable	Fossil fuels disallowed anywhere in the economy; nuclear retired.	Highest Cost
No Thermal	Forced retirement of all gas and oil electricity generation.	Highest Cost

Variations applied to *All Options*

All pathways were analyzed using the EnergyPATHWAYS and RIO models developed by Evolved Energy Research. Section 3 of the main text provides a longer description of the modeling methods and data sources used in the analysis.

1.3 Key Results

The emissions path to Net Zero can be divided into three stages, in which different measures play the main role in emissions reductions in each stage. *Near term* emissions reductions come primarily from increasing efficiency,[2] continuing to build-out solar PV, and importing low-carbon electricity from out-of-state. In the *medium term*, further reductions come primarily from building offshore wind and achieving high levels of electrification.[3] In the *long term*, the decarbonization of remaining fuel uses (e.g. jet fuel) are added to the prior strategies. This general sequence reflects the lowest cost transition for Massachusetts, with nuances and variations in this basic template depending on the specific pathway.

[2] Even in the low-efficiency pathway, some electrification measures still resulted in efficiency improvements that decreased energy use per person.
[3] High building electrification was not assumed in every pathway, but low electrification of both buildings and transport was found to be incompatible with the net-zero emissions target given environmental constraints on biomass availability.

Economy-wide decarbonization is the result of actions taken within each sector, and across sectors. Key findings from the modeling include:

Energy Efficiency

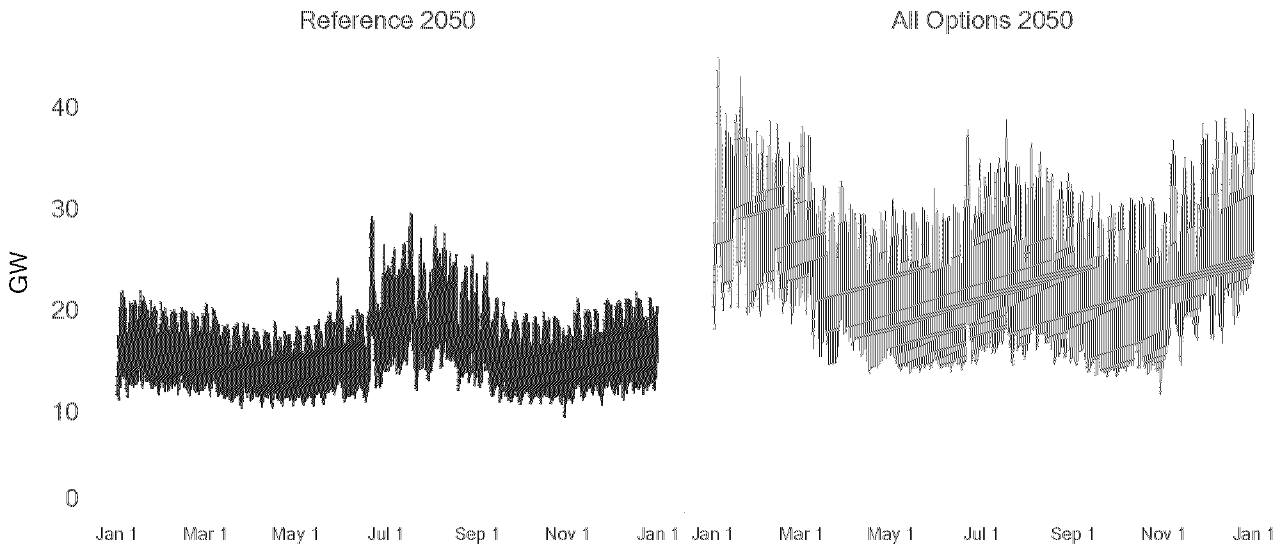
- Reduced deployment of energy efficiency resulted in significantly higher infrastructure requirements, including a 50% higher offshore wind build from 2030 to 2045.
- The efficiency measures adopted in buildings, industry, and aviation became more cost-effective as the carbon emissions limit tightened over time. By 2050, every dollar invested in efficiency returned $1.50 in avoided energy costs.

Building electrification

- Given the assumptions of this analysis, high levels of building electrification lowered the long-term cost of reaching Net Zero. With less building electrification, the long-term cost of the decarbonized fuel required to reach the emissions target more than offset modest cost savings from avoiding electrification in the near term.
- The large quantity of decarbonized drop-in fuels required is a risk factor for a low building electrification pathway. Even with nearly complete electrification of on-road vehicles, bioenergy imports would nonetheless need to increase to five times the level of ethanol imports today.
- In a low building electrification pathway, average gas rates increased from roughly $10/MMBtu to $20-$30/MMBtu due to a combination of biogas cost, lower pipeline throughput, and the marginal carbon price of the remaining natural gas in the system. This makes gas less competitive with electricity than it is today. If adoption of electric technologies is seen by customers as cost effective based on the relative retail rates of gas and electricity, there could be an uncontrolled exit from the gas system and escalating rates for the remaining customers.
- A high building electrification pathway, whether resulting from explicit policy or market choices by consumers, will require a policy strategy for how to manage an orderly and equitable exit from the gas distribution system.
- Building electrification will lead to increases in peak electric load. However, the relative impact of such an increase depends on the level of EV adoption and the flexibility of EV charging (Figure ES2).[4] After assuming high levels of EV adoption, the incremental impact of building electrification was a relatively modest 30% increase to distribution peak loads.
- Key uncertainties about building electrification that require in-depth study include the impact of space heating electrification on distribution feeders above and beyond the impact of vehicle electrification; the future cost of decarbonized fuel imports; and the eventual savings from retirement of gas distribution.

[4] The base assumption was that 50% of all light duty vehicle charging load was flexible, and that it could be delayed by up to eight hours during the day.

Figure ES2. ISO-NE system load shape comparison in 2050, after the dispatch of flexible loads.



Transportation electrification

- Rapid electrification of light-duty transportation is a no-regrets strategy for Massachusetts, including reaching 50% of sales of zero emission light-duty vehicles by 2030.
- Medium- and heavy-duty transportation must also rapidly transition towards battery-electric or hydrogen fuel cell vehicles. Nevertheless, a limited quantity of residual liquid fuel use in on-road transportation is compatible with reaching Net Zero.
- Aviation efficiency improvements are important for reducing cost and reducing the amount of decarbonized fuel imports required.

Industry

- The primary decarbonization strategies for industry are energy efficiency in the near term, electrification in the medium term, and deployment of carbon capture and use of decarbonized fuels in the long term.
- Electrification opportunities exist in lower-temperature process heat and steam generation, especially when paired with flexibility in time of use that takes advantage of available renewable generation.

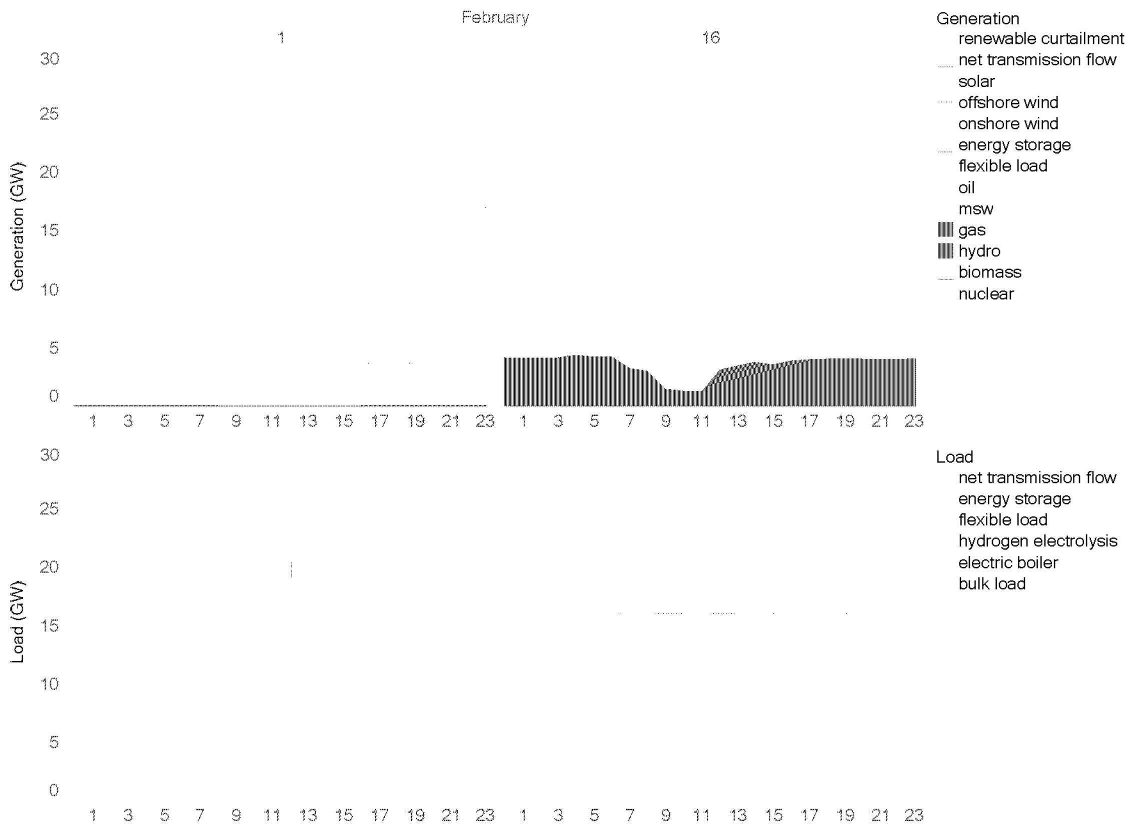
Electricity generation

- Offshore wind is the backbone of decarbonized electricity generation in Massachusetts. Across all the pathways, a minimum of 15 GW of offshore wind was installed in Massachusetts waters by 2050.
- When offshore wind deployment was limited, imported electricity from Quebec was used to make up the difference. New nuclear generation was also found to be cost-effective in the Northeast region under these circumstances.
- Solar PV made up 25%-30% of electricity generation across most pathways, limited by the cost of storing and shifting in time excess solar generation. Both rooftop PV and ground-mounted PV were needed.
- Very high rooftop solar deployment significantly reduced the land-use required for ground-mounted renewables, but also increased capital cost. In general, because the resources have similar attributes, the relative share of rooftop and ground-mounted solar did not have a large impact on decarbonization results.

Electricity balancing

- In a future with high levels of offshore wind capacity, the primary electricity balancing challenge for the region will be infrequent but long-lasting periods of fallow production. This is illustrated in Figure ES3, showing electricity operations on two simulated days in 2050. The comparison shows that thermal power plants and imports were not needed on a high-wind day but were required at a large scale to maintain reliability on a low-wind day.
- Canadian hydro is an essential element of regional balancing. In this analysis, the Quebec hydro system transitioned over time into the role of a 'battery' for the Northeast region, with electricity flowing in both directions, depending on the timing of renewable production and loads on both sides of the U.S.-Canada border. Because flows were bidirectional, total net-imports into Massachusetts from Quebec declined after 2035 in the analysis.
- Flexible operation of electrolysis facilities to produce hydrogen, and of electric boilers to produce steam, are critical enablers of a high wind and solar system. They help to reduce electricity system costs by providing productive uses for renewable overgeneration and simultaneously reducing emissions in other sectors (heavy transport and industry).
- New battery electric storage for shifting renewable energy supply in time played only a minor role in balancing the bulk power system. This was due to the combined effects of the timing of renewable generation in a wind-heavy system, existing pumped storage capacity, and the capabilities of transmission ties with Quebec. However, flexible end-use demand proved valuable for reducing transmission and distribution costs, suggesting a potentially important role for storage in similar applications.
- Because of the need for firm capacity on a handful of days, thermal generating capacity without carbon capture is the other essential component of low-cost electricity balancing. There was no significant change in the size of the gas turbine fleet in the region by 2030 in most pathways. Thermal power plants are difficult to replace economically because of the occurrence of lengthy periods with low wind output (72+ hours).
- Thermal capacity without carbon capture, while critical for reliability, operated infrequently. Thermal generation for some number of hours was needed on 1/3 of the days in 2050 but on only 12 days during the year was thermal generation required during every hour, corresponding to days with very low offshore wind production. This means thermal power plants contributed only a small share of annual generation (<6.2%). Because the actual energy produced in thermal power plants was low, even burning natural gas in them produced relatively few emissions. For the same reason, the incremental cost of replacing natural gas with a combination of hydrogen and biogas to completely eliminate emissions in electricity was small.
- Nuclear and fossil generation with carbon capture were found to be uneconomic ways of providing reliability in a high renewables system, since the limited number of hours they would operate do not justify the large incremental capital cost of replacing existing thermal power plants.

Figure ES3. All Options pathway daily operations for Massachusetts in 2050. February 1st (left, a high offshore wind generation day) is contrasted to February 16th (right, lowest offshore wind day of the year). Generation is shown in the top panel for each day, and load in the bottom panel. The right-hand figure illustrates the types of capacity, primarily gas thermal generation and transmission imports, required to maintain system reliability on low wind days. The left-hand figure illustrates the role of transmission exports and flexibly operated end uses such as electrolysis on high-wind days.



Transmission

- Expanded transmission capacity between Quebec and Massachusetts was important in all pathways, with a minimum of 2.7 GW and a maximum of 4.8 GW required above today's level. In the near term, these lines were used to import carbon-free electricity from Quebec, largely from new onshore wind projects. In the long term, the lines were used to allow bi-directional power flow for balancing a high renewables power system throughout the Northeast region.
- New transmission capacity connecting the northern part of Massachusetts with New Hampshire, and the western part of Massachusetts with New York, was found to be economic in multiple pathways.
- Interconnection of offshore wind and ground-mounted solar to load requires significant new transmission capacity in any high-renewables power system in New England.
- Substantial expansion of transmission and distribution within Massachusetts was necessary to meet the approximately doubled final electricity demand resulting from electrification.
- Mandating the retirement of all thermal gas power plants by 2050 resulted in tripling the long-distance transmission capacity required in the region to balance renewable variability.

Decarbonized Fuels

- Remaining fuel uses in 2050 included aviation, asphalt, and shipping at levels similar to today's, along with reduced but continued use of fuels in buildings, industry, and transportation. This fuel demand was met largely with fuels synthesized from biomass or derived from electricity (hydrogen produced with electricity and combined with captured CO_2).

- Liquid fuels were more cost-effective to substitute with decarbonized alternatives than natural gas because the avoided cost of replacing refined petroleum products is roughly five times greater than for natural gas.[5]
- Imports of ethanol, currently blended into motor gasoline, were gradually replaced with imports of other biofuels for different applications after the electrification of light-duty vehicles. With high electrification of both buildings and transportation, total imports of bioenergy increased 50% by 2050.
- Large supplies of biofuels other than ethanol will not be required until about 2040 unless rapid decarbonization of electricity is not achieved. Nonetheless, the cost, quantity available, and environmental sustainability of imported biofuels are major uncertainties requiring further in-depth study.

Costs and Tradeoffs

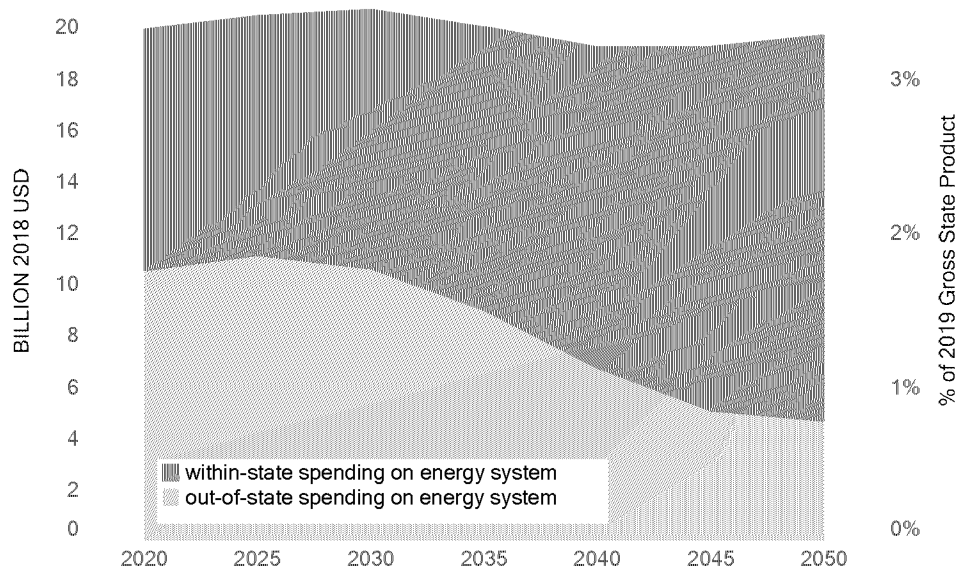
This analysis provides two types of information of value to Massachusetts residents and officials in considering policy options for reaching Net Zero. First, it highlights "no-regrets" strategies that appear in all decarbonization pathways and for which the need is unquestioned, including increasing energy efficiency and rapid deployment of renewables and electric vehicles. Second, it highlights tradeoffs and cost differences between different pathways that will have to be carefully weighed, and in some cases requires new analysis and pilot projects to fully understand the implications. Key examples include:

- Offshore wind plays a critical role in electricity generation in all pathways, but with it comes the need for transmission to bring it to shore and balance its variability, and potential impacts on visual aesthetics and marine environments. If the construction of offshore wind is not achieved at the scale suggested here, the construction of new nuclear in the Northeast region may be required in order to meet the Net Zero target.
- Natural gas is the least expensive fossil fuel and continuing to use it as a transition fuel can help reduce the cost of a low-carbon transition. On the other hand, pathways that maintain a high volume of pipeline gas consumption indefinitely, as in the Pipeline Gas pathway, will be critically dependent on the quantity and cost of decarbonized fuels available in order to reach Net Zero.
- Increasing regional coordination in electricity offers a clear opportunity to reduce overall costs, but involves building new transmission capacity, and likely requires new supporting policies in regional electricity markets. Similarly, flexible end-use loads also offer overall cost-savings, but require investment and electricity market changes.
- Retiring existing natural gas power generation in the absence of unforeseen breakthroughs in long-duration energy storage technology will lead to dramatic cost increases for providing alternative strategies for electricity balancing.
- Mandating all energy supplies, not just electricity, to be 100% renewable could lead to cost increases. Commitment to such a goal should be made only with a better understanding of long-term bioenergy cost and availability than currently exists.
- Low energy efficiency and low building electrification both lead to modest cost increases, but also result in higher use of other resources.

[5] Today, natural gas is roughly \$3/MMBtu while refined petroleum fuels are roughly \$15/MMBtu.

- In all decarbonization pathways, there is a shift away from purchasing energy from outside Massachusetts toward investing in capital equipment in the state,[6] as shown in Figure ES4. The *Decarbonization Roadmap to 2050* and the companion *Economic and Health Impacts Report* will help to quantify the macroeconomic and employment benefits from this shift towards in-state spending as seen in Figure ES4.

Figure ES4. In-state vs. out-of-state spending on energy for the reference and all options pathways, in dollars and as a percentage of 2019 gross state product ($600B).



The themes and results presented in this executive summary are described in greater detail in the main text of this document. Section 2 describes the goals of the study, the general approach taken to address them, and compares the study to past regional studies. Section 3 describes the modeling tools used in this work and the associated limits and uncertainties. Section 4 describes the eight pathways analyzed in detail, including input assumptions and why each was chosen. Section 5 presents detailed results for each pathway along multiple dimensions. Section 6 synthesizes these results into common findings, areas of competition, and outstanding research questions in order to communicate the energy system decisions faced by the region with sufficient clarity to allow policymakers and policy implementers to carefully weigh the tradeoffs and shape effective public policy in the years to come.

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[6] Implicitly assumed is that offshore wind installed in Massachusetts waters is also manufactured in Massachusetts. Economic activity within the state, region, and U.S. at large will depend on the supply-chain for different technologies, for which policy has the opportunity to help shape.

2 Introduction

2.1 Study framework

Massachusetts has set a target of net-zero greenhouse gas (GHG) emissions by 2050. This report is one component of the broader Decarbonization Roadmap Study ("Roadmap Study") led by the Massachusetts Executive Office of Energy and Environmental Affairs (EEA) that maps out strategies for reaching this target. This document focuses on how the largest single component of GHG emissions, carbon dioxide (CO_2) from energy and industry (E&I),[7] can be dramatically reduced or eliminated while maintaining a vigorous state economy. It describes eight different technological pathways for deep decarbonization of the Northeast region, with an in-depth treatment of Massachusetts.

The parallel research efforts of the Roadmap Study are shown in Table 2. This study, *Energy Pathways to Deep Decarbonization*, along with the *Non-Energy Sector Technical Report*, serve to analyze pathways to achieve a 90% reduction from 1990 GHG emissions. In addition, the Land Use study analyzed how natural and working lands in the Commonwealth can help remove residual emissions in 2050 in order to bring Massachusetts to a net-zero economy. This study also intersects with the sector analyses of buildings and transportation, which take a deeper dive into these areas. All of the sector analyses are used in developing the 2050 Roadmap and the Clean Energy and Climate Plan for 2030.

Table 1. Analyses for Massachusetts Net Zero by 2050 report.

Study	Description
Energy Pathways to Deep Decarbonization	This report. Study of the whole energy economy with particular focus on electricity and regional decarbonization strategies.
Non-Energy Sector Technical Report	Study of non-CO_2 greenhouse gas mitigation potential.
Land Sector Technical Report	Study of the CO_2 land sink and associated questions.
Transportation Sector Technical Report	Deeper dive on questions surrounding transportation
Buildings Sector Technical Report	Deeper dive on questions surrounding buildings
Massachusetts Decarbonization Roadmap to 2050	Synthesis document covering each of the sector analysis chapters
Economic and Health Impacts Report	Analysis of economic and health impacts from decarbonizing the Commonwealth's energy system.
Clean Energy and Climate Plan for 2030	Policy recommendations

This report does not set out to identify which, if any, of the eight pathways is the 'right' pathway for the Commonwealth. Instead, it compares them in order to understand the tradeoffs, decision points, risks, and commonalities. It provides policymakers, private industry, and stakeholders in the Commonwealth and regionally with the information needed to continue charting a path forward, starting with policies necessary to reach interim 2030 targets.

[7] The term energy and industrial emissions is used because this analysis also encompasses industrial process related CO_2 emissions.

2.2 Study questions

The research team set out to answer two primary questions: (1) is it possible to reach E&I emissions consistent with Net Zero by 2050 in Massachusetts; and (2) if it is possible, what are the actions required in the E&I sectors, and what are their implications? The team has concluded that the answer to the first question is 'yes' and that multiple pathways to reach the Commonwealth's goals exist; however, each comes with challenges and requires a transformation of the energy system at a pace that may seem daunting. Given the long lifetimes of energy infrastructure, the time remaining to 2050 is short. Additionally, the importance of energy services to our way of living is profound, and addressing the prevalence of fossil energy in providing those energy services in our current system is paramount. The rest of this report is dedicated to answering the second question regarding the actions, and associated implications, required to reach emissions reductions consistent with Net Zero by 2050.

The Northeast region has a unique set of energy planning characteristics, relative to the rest of the United States. The Northeast energy system is more similar to those in northern Europe, and very different from other jurisdictions in the U.S. that are also pursuing aggressive climate policy, such as California. Unique factors for the Northeast include:

- Emissions targets of at least an 80% reduction in GHG emissions by 2050 across the entire region;
- High population density leading to difficult resource siting;
- Significant interties with a large hydro-electric system (Hydro Quebec);
- Large offshore wind potential;
- Moderate solar resource quality;
- No geologic sequestration potential;
- And, large winter heating loads.

Deep decarbonization pathways in Massachusetts must account for each of these factors and may differ in the details when compared to strategies employed elsewhere based on a different mix of resources, challenges, and opportunities. In this analysis, we have drawn on the experience of other regions in mapping decarbonization pathways, but with tools, data, and constraints tailored specifically to the Northeast. Our analysis also builds on a rich set of previous analyses discussed in section 2.4.

2.3 The role of pathways in planning

This analysis uses the term "pathways" to mean a blueprint for the energy system that reaches future GHG reduction targets. The term is used in referring to both a specific strategy and to a set of different possible blueprints (as in, "multiple pathways to deep decarbonization"). The term 'pathway' was first used by the Deep Decarbonization Pathways Project (DDPP) in 2014,[8] and was coined to capture the path dependency[9] within different decarbonization strategies. While the physical transformations represented by these pathways

[8] Deep Decarbonization Pathways Project. http://usddpp.org/

[9] Path dependency is another way of saying history matters. Technological decarbonization is a stock turnover problem in which a set of mutually supporting actions must be taken in sequence. A vision of a transformed energy system is only useful when it can be mapped to a set of incremental steps starting from the current energy system, a process often referred to in the decarbonization literature as backcasting.

are informed by economic, social, and political constraints, they should not be mistaken for the impacts of a specific policy or market intervention.

The study of long-term decarbonization pathways has been a growing trend after early success using them in California. Our ability to model decarbonization pathways begins with our ability to represent the existing energy system with a high degree of accuracy. Significant effort goes into benchmarking and stress-testing the models of our current energy systems until researchers have a high degree of confidence that changes in inputs will produce meaningful outputs. After California, other states (Washington, New York) followed suit with their own pathways analyses. Pathways analysis has become an integral part of energy planning processes, and yet, because of the breadth of topics covered and the time horizon analyzed, it is still a unique activity within state-level public policy processes and merits some clarification.

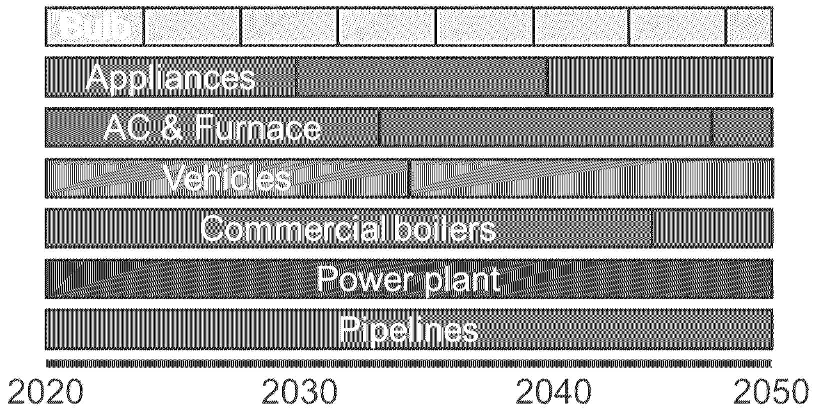
The most critical clarification is that pathways are not forecasts of what will happen. While the energy system physics and emissions accounting that underpin our models are well established, projections of technological progress (particularly cost) and energy service demand has a mixed track record—even over timespans much shorter than 30 years. This means that selecting a single pathway as the basis for public policy is fraught, since the assumptions that cause it to be a better option in the present may end up shifting over time. Input uncertainty necessitates an ongoing planning process, with periodic updating as new information becomes available and progress, or lack thereof, toward goals is achieved.

Rather than providing a prediction of the future, pathway studies are valuable for four reasons:

- Avoiding dead-end strategies;
- Mapping forks in the road;
- Identifying commonalities across sensitivities;
- And, situating near-term policy targets with respect to long-term goals.

Infrastructure that produces, delivers, and consumes energy is both capital intensive and has very long lifetimes. This is illustrated in Figure 1, which shows the number of replacement cycles for common infrastructure types between now and mid-century. If a pathways analysis looked only 10 to 15 years ahead, as is typical in electric utility integrated resource plans, decisions might be made that efficiently reduced emissions to hit near-term targets but were inconsistent with long-term goals, locking in higher emissions or increasing cost after necessitating early retirement. Thus a 30-year pathways study is able to test a given decarbonization strategy against this backdrop of infrastructure lifetimes in order to understand whether an emissions dead-end will be encountered on a given path. The timing of decision forks can also help to avoid stranded assets.

Figure 1. Overview of the lifetimes of common energy consuming or producing infrastructure. A simplified overview of the lifetimes of common energy consuming or producing infrastructure are compared against the 30-year time period left to reach the net-zero target. The black vertical lines delineate points of natural retirement and the number of segments correspond to the number of replacement cycles between now and 2050. The lifetime of vehicles varies by location and duty-cycle. The lifetime of power plants and pipelines is longer than 30 year and thus no natural retirement is shown on this figure.



As mentioned, the future trajectories of many variables, including technology cost and performance projections, are highly uncertain. However, it is possible to develop ranges of values in which the high and low estimates have a high probability of encapsulating the eventual revealed value for any variable. Creating multiple pathways (eight in this analysis) allows us to test the sensitivity of results to a range of input assumptions. The most useful result is not the precise blueprint embodied in any specific pathway but identifying those strategies that are common across all pathways along with identifying the drivers of differences among pathways. As will be detailed later in this report, a set of strategies can be identified over the next 10 years that are common to all pathways that successfully reach the net-zero target.

Finally, pathways studies can be very valuable in near-term target setting. Back casting from a 2050 net-zero energy system to the present allows the identification of certain milestones or benchmark values (often ranges) that are consistent with being on track to reach the long-term goals. Near-term targets will be discussed in more detail in the Clean Energy and Climate Plan for 2030 and are not a focus in this report.

2.4 Past work

This report is the latest in a line of analyses in the Northeast on decarbonized energy systems. It is the first study to examine energy and industrial emissions targets consistent with net-zero GHGs by 2050 for the region. It is also the first to represent the transition from 2020 to 2050, including intermediate years, using optimal capacity expansion modeling methods, as well as the first to represent transmission within New England in a study of long-term regional coordination.

The modeling team for this report also wrote the 2018 report “Deep Decarbonization in the Northeast United States and Expanded Coordination with Hydro-Québec” (“2018 DDPP Study”).[10] The Massachusetts analysis in this study improves upon the 2018 DDPP Study by increasing the geographic granularity (10 instead of 4

[10] Sustainable Development Solutions Network, Evolved Energy Research, and Hydro-Quebec, Deep Decarbonization in the Northeastern United Stated and Expanded Coordination with Hydro Quebec, April 2018. https://irp-cdn.multiscreensite.com/be6d1d56/files/uploaded/2018.04.05-Northeast-Deep-Decarbonization-Pathways-Study-Final.pdf

electricity load zones), by employing optimal capacity expansion in the electricity and fuels systems instead of scenario analysis, and by expanding the breadth of the research questions. The 2018 DDPP Study also focused on 80x50 emissions[11] targets, rather than Net Zero. The modeling conducted for this report includes a total refresh of data and assumptions, including new factors overlooked in the 2018 work, such as the impact of vehicle electrification in Quebec on the energy available for export.

The findings from the 2018 DDPP Study were reinforced by a study released in the same year titled "A Decarbonized Northeast Electricity Sector: The Value of Regional Integration" ("2018 Pineau Study").[12] The 2018 Pineau Study looked at electricity only, with an emissions reduction of goal of 80% below 1990 levels in that sector, which is inconsistent with a net-zero goal for the region. The study was the first to use capacity expansion to look at trans-border coordination, but it did not solve for transmission expansion, it used present day load shapes, and it did not solve for intermediate years on the way to 2050—instead imagined a blank-slate scenario in which the power systems start from scratch with only hydro remaining.

National Grid also released an 80x50 study in 2018 that primarily focused on the intermediate year 2030 and, like the 2018 Pineau Study and 2018 DDPP Study, analyzed all of New England together.[13] The pace of change analyzed is much slower than the pace identified in this study as necessary to reach a net-zero target in some sectors, namely electricity, but much faster in others, like transportation electrification.

Northeast Energy Efficiency Partnerships (NEEP) released a study in 2017 titled "Northeastern Regional Assessment of Strategic Electrification" ("2017 NEEP").[14] This study also analyzed New England as a whole, focused on 80x50, and made timely contributions to identifying the barriers around electrification in the Northeast.

A recent look at electrification of buildings was released in 2020 by the Brattle Group titled "Heating Sector Transformation in Rhode Island – Pathways to Decarbonization by 2050" ("2020 Brattle").[15] This study finds the electrification of water heating to be cost effective, but the economics in space heating between electrification and renewable gas to be uncertain. It is likely these findings were affected by the omission of other sectors in the analysis. For example, vehicle charging is typically not coincident with space heating peak load, and while either can trigger distribution system upgrades, load factors are higher, and distribution system economics improved, when both are combined. Also, the same feedstocks that are used to make renewable gas have competing uses such as aviation fuel, driving up renewable gas costs and limiting availability. In addition, the assumptions used by Brattle about heat pump technology performance, heat pump cost, decarbonized electricity generation cost, and coincidence between heating peak load at households throughout New England, are different from those in this study, as outlined in Section 7.

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[11] In this analysis, 80x50 emissions target means an 80% reduction in GHG emissions by the year 2050 off of a 1990 baseline.

[12] A Decarbonized Electricity Sector: The Value of Regional Integration, June 2018, http://energie.hec.ca/wp-content/uploads/2018/06/ScopingStudy_NortheastHydroModelling_13june2018.pdf

[13] National Grid, Northeast 80x50 Pathway, https://www.nationalgridus.com/news/assets/80x50-white-paper-final.pdf

[14] Northeast Energy Efficiency Partnership, Northeast Regional Assessment of Strategic Electrification, July 2017, https://neep.org/sites/default/files/Strategic%20Electrification%20Regional%20Assessment.pdf

[15] The Brattle Group, Heating Sector Transformation in Rhode Island, https://www.brattle.com/reports/heating-sector-transformation-in-rhode-island

The latest in the line of studies examining the value of coordination between Canada and the U.S., "Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower" was released in 2020 by MIT ("2020 MIT")[16]. The findings are broadly similar to the previously described work on the topic, namely, that increasing regional transmission and coordination has significant value for a decarbonizing electricity system. However, the capacity expansion framework employed in this study did not have transmission within New England, did not model any intermediate years between the present and 2050, and lacked some key technology options required in a least-cost regional electricity system. For example, the difference in renewable curtailment between 99% and 100% electricity decarbonization cases would be reduced significantly if a portion of the observed curtailment was used to make clean fuels, allowing its use in thermal power plants and thereby avoiding the addition of renewables with high marginal curtailment rates.

A decarbonization study within Massachusetts, The Carbon Free Boston Report[17] produced by the Boston University Institute for Sustainable Energy for the Green Ribbon Commission, evaluated the impact of near city-wide electrification on demand to show large increases in winter electricity consumption. The report also noted that if Boston were to achieve its carbon neutrality goals, it would need to make a large procurement of renewable energy beyond those prescribed for utilities by state policy. With Boston currently consuming more than a tenth of the Commonwealth's energy, and other communities making similar goals, there may be a patchwork of town-level polices that could complement or potentially complicate the Commonwealth's efforts.

The detailed assumptions and methodology for this study are presented in Sections 7 and 9 to allow for additional points of comparison between our findings and prior work.

[16]MIT Center for Energy and Environmental Policy Research, Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower, February 2020, http://ceepr.mit.edu/publications/working-papers/719

[17] Boston University Institute for Sustainable Energy, Carbon Free Boston Reports, http://sites.bu.edu/cfb/carbon-free-boston-report-released/

3 Methodology overview

Section 3 provides an overview of the modeling methodology used in this analysis, a summary of the data inputs, and highlights many of the uncertainties inherent in this type of pathways analysis.

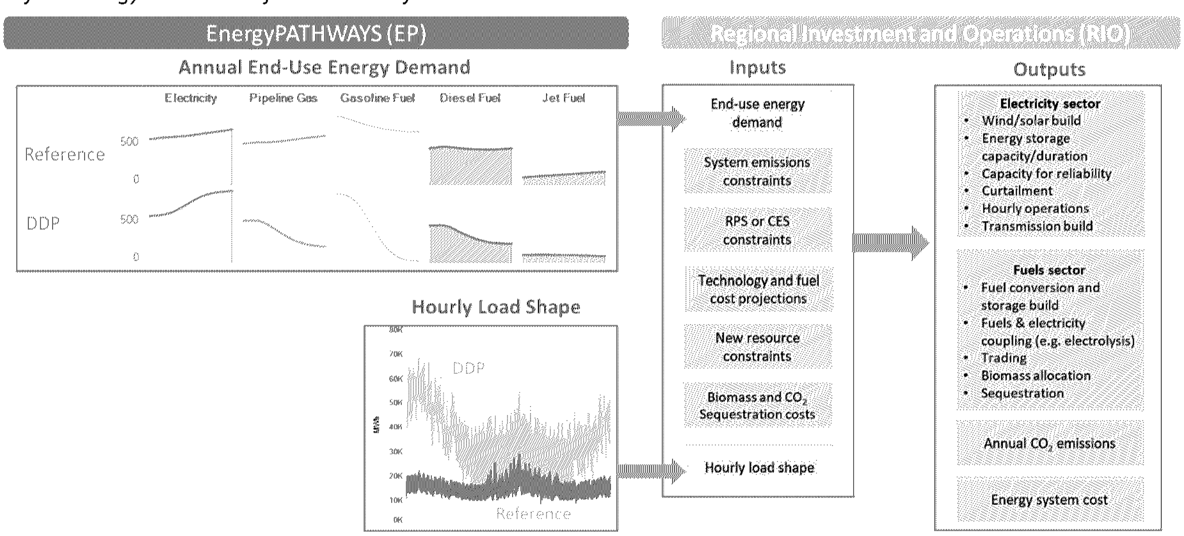
3.1 Modeling framework

Modeling of the energy and industrial sectors in this study was performed using RIO and EnergyPATHWAYS (EP), both of which are numerical models with high temporal, sectoral, and spatial resolution developed by Evolved Energy Research to study energy system transformation. EP is a bottom-up stock accounting model used to create final-energy demand across sixty-four demand subsectors and twenty-five final energy types. This final energy demand for fuels along with time-varying (8760 hour) electricity demand profiles are used as inputs to RIO, a linear programming model that combines capacity expansion and sequential hourly operations to find least-cost supply-side pathways.[18] This pair of models produces energy, cost, and emissions data over the 30-year study period, 2020 – 2050. Interactions between EP and RIO are illustrated in Figure 2.

RIO has unique capabilities for this analysis because it models detailed interactions among electricity generation, fuel production and consumption, and carbon capture with high temporal granularity, allowing accurate evaluation of coupling between these sectors in the context of economy-wide emissions constraints. Additionally, RIO tracks fuels and energy storage state of charge over an entire year, making it possible to assess electricity balancing in high variable generation systems; RIO also solves for all infrastructure decisions on a five-year time-step to optimize the energy system transition, not only the endpoint of the period. This is the first study of the Northeast to combine these capabilities to examine net-zero economy-wide scenarios.

The following two sections provide additional detail on the EP and RIO models with a full methodological description provided in the Section 9.

Figure 2 EnergyPATHWAYS and RIO modeling flow-chart using illustrative data (study results are not pictured). EnergyPATHWAYS is used to create final energy demand and hourly electricity shapes that get passed into the RIO model. RIO optimizes the decisions to meet this final energy demand subject to user-defined constraints.



[18] Capacity expansion refers to the capability in an optimization model to choose the capacity of power plants in addition to their operation.

3.1.1 **EnergyPATHWAYS (EP)**

EnergyPATHWAYS (EP) is a bottom-up stock-rollover model of all energy-using technologies in the economy, employed to represent how energy is used today and in the future. It is a comprehensive accounting framework[19] designed specifically to examine large-scale energy system transformations. It accounts for the costs and emissions associated with producing, transforming, delivering, and consuming energy in the economy.

The model assumes decision-making stasis as a baseline. For example, when projecting energy demand for residential space heating, EP implicitly assumes that consumers will replace their current water heater with a water heater of a similar type. This baseline does; however, include efficiency gains and technology development that are either required by regulatory codes and standards or can be reasonably anticipated based on techno-economic projections. Departures from the baseline are made explicitly in scenarios through the application of *measures*. Measures can take the form of changes in sales shares (the adoption of a specific technology in a specific year) or in changes of stock (the total technology deployed in a specific year). Approximately 30 economic subsectors are represented by stock rollover, meaning changes in stock as new stock is added and old stock is retired. Other sectors that lack sufficiently granular data to create a stock representation are modeled with aggregate energy demands that trend over time or are exogenously specified from sources like the U.S. Annual Energy Outlook (e.g. aviation). These non-stock subsectors still have fuel switching and electrification measures applied at an assumed cost, but with less specificity in the underlying technology transition.

Inputs to determining final energy demand include:

1. Demand drivers – the characteristics of the energy economy that determine how people consume energy and in what quantity over time. Examples include population, square footage of commercial building types, and vehicle miles traveled. Demand drivers are the basis for forecasting future demand for energy services.
2. Service demand – energy is not consumed for its own sake but to accomplish a service, such as heating homes, moving vehicles, and manufacturing goods.
3. Technology efficiency – how efficiently technologies convert fuel or electricity into energy services. For example, how fuel efficient a vehicle is in converting gallons of gasoline into miles traveled.
4. Technology stock – what quantity of each type of technology is present in the population and how that stock changes over time. For example, how many gasoline, diesel, and electric cars are on the road in each year.

EP determines sectoral energy demand for every year over the model time horizon by dividing service demand by technology efficiency, taking into account the stock composition. Service demand and technology stocks are tracked separately for each zone (zones are shown in Figure 6) and the aggregate final energy demand must be met by supply-side energy production and delivery, modeled in RIO.

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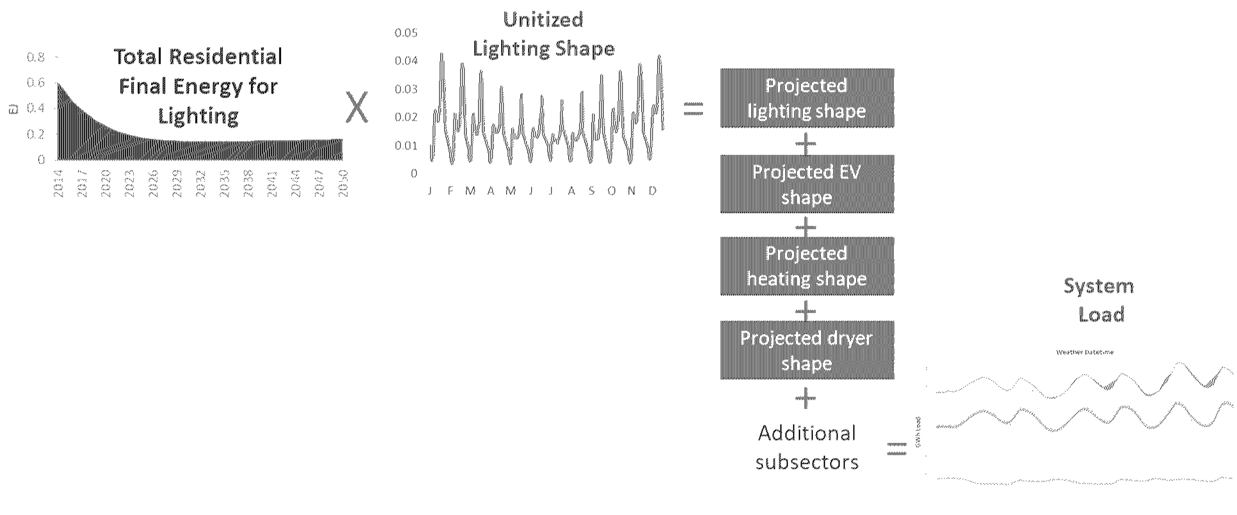
[19] EnergyPATHWAYS is a scenario accounting tool that tracks user-defined decisions on the evolution of end-use energy. Unlike RIO, it does not optimize decisions based on cost or other criteria. The demand-side lends itself to scenario analysis because: (1) consumer decisions often do not reflect a cost minimization; (2) demand solutions between subsectors have fewer interactive effects than on the supply side; (3) the basic strategies of efficiency and fuel-switching (electrification) have few degrees of freedom when studying net-zero carbon targets (e.g. actions do not "trade-off" against one another as might happen when studying less aggressive carbon targets because all are actions are required at a high degree).

Due to the importance of hourly fluctuations in electricity demand when planning and operating the electricity system, a final step is taken in EP to build hourly load shapes bottom-up for future years, illustrated in Figure 3. Each electricity-consuming sub-sector in the model has a normalized annual load shape with hourly time steps. Electrical final energy demand is multiplied by the load shape to obtain the hourly loads of each subsector. These are aggregated to obtain estimates of bulk system load. Benchmarking is done against historical system load shapes and correction factors are calculated and applied to correct for bias in the bottom up estimates. After calibration, the calculated bottom-up load-shape in the first year matches historical system-wide load. The same correction factors are carried forward and applied to future years.

Figure 3 EP estimates system load shapes bottom-up by multiplying annual energy consumption by hourly allocation factors representing service demand patterns. Estimates for hourly allocation factors come from a variety of sources, listed in Section 7.6. A benchmarking process is used to compare bottom up estimates with 'known' historical bulk load that results in a series of correction factors, applied across future years.



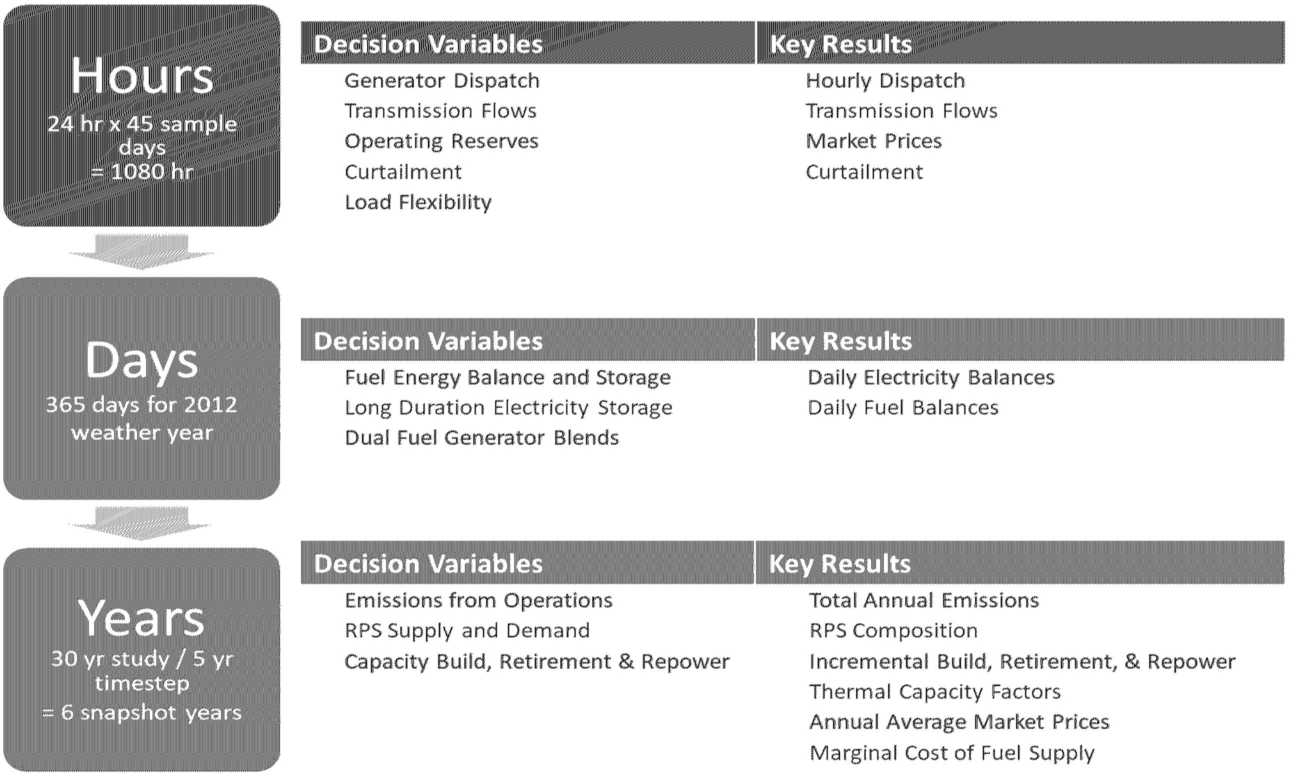
3.1.2 **Regional Investment and Operations Model (RIO)**

On the supply side, least-cost investments in electricity and fuel production to meet carbon and other constraints are determined using a capacity expansion model called the Regional Investment and Operations model (RIO). RIO is a linear program that optimizes investments and operations starting with current energy system infrastructure. It incorporates final energy demand in future years, the future technology and fuel options available (including their efficiency, operating, and cost characteristics), and clean energy goals (such as RPS, CES, and carbon intensity). Operational and capacity expansion decisions are co-optimized across the ten study zones.

Multiple timescales are simultaneously relevant in energy system planning and operations, and the emerging importance of variable generation (wind and solar) in future power systems means that high temporal fidelity in electricity operations has increased in importance. RIO decision variables and temporal scales are shown in Figure 4.

The most important distinction between RIO and other capacity expansion models is the inclusion of the fuels system, making it possible to co-optimize across the entire supply-side of the energy system, while enforcing economy-wide emissions constraints within each zone. This is important for accurate representation of the economics when electricity is used for the production of fuels, for example when renewable over-generation is used for the production of hydrogen.

Figure 4 Relevant time scales in RIO along with the decision variables and key results for each. The model works to find a solution to each decision variable that minimizes total energy system cost while respecting all user-defined constraints, such as annual carbon emissions.



RIO utilizes the 8760 hourly profiles for electricity demand and generation from EnergyPATHWAYS but optimizes operations for a subset of representative days ("sample days") before mapping them back to the full year (Figure 5). Operations are performed over sequential hourly timesteps. Clustering of days using several dozen features or diurnal 'characteristics' is used with careful attention to ensure that the sampled days represent the full range of conditions encountered in the historical weather year. The clustering process is designed to identify days that represent a diverse set of potential system conditions, including different fixed generation profiles and load shapes. The number of sample days impacts the total runtime of the model and trades off with the ability to represent a range of historical conditions. Across the ten Northeast region zones, 45 sample days was found to strike the right balance, giving both good day sampling statistics (provided in Section 7.1) and reasonable model runtimes (72 hours).

Figure 5 Operational framework for the RIO model. Forty-five sample days map back to 365 days over which fuels and long duration storage are tracked. The model represents years 2020 – 2050 with a 5-year timestep.

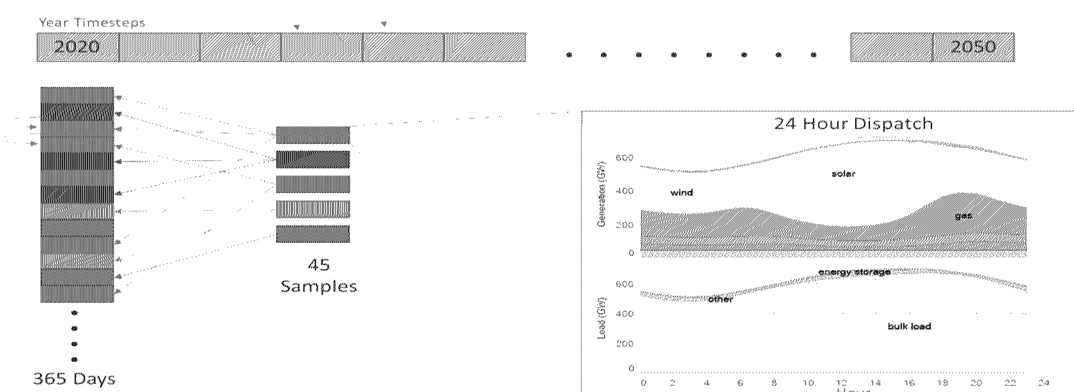


Table 2 provides a full list of RIO features along with the specific configurations used here. Additional detail on the RIO model is provided in the appendix.

Table 2 List of important RIO features and parameters

Feature	Settings used for the Massachusetts DDP Analysis
Optimal generator selection	All generator types listed in Section 7.8.
Optimal energy storage selection	Optimal selection of energy & capacity, priced separately.
Long duration storage	Enabled with tracking of long duration state of charge across 365 days.
Optimal transmission selection	Enabled for all existing paths and Quebec to Maine.
Optimal fuel technologies	Flexible framework allowing for selection and operations of any fuel conversion and supply infrastructure. Fuel conversions that consume electricity allowed to co-optimize operations with electricity generation.
Fuels storage	Optimal build and state-of-charge tracking over 365 days for hydrogen.
Dual fuel generators	All existing and new gas generators capable of burning a hythane mix of up to 60% hydrogen.
Flexible load	Traditional load shedding and a detailed framework with cumulative energy constraints for end-use flexible loads. Methodology illustrated in Section 7.10.
Number of zones	10 zones co-optimized in RIO
Number of resource bins	15 NREL technical resource group (TRG) bins for wind and 6 bins for solar PV per zone.
Year timestep	Model run for the years 2020, 2025, 2030, 2035, 2040, 2045, 2050.
Hours modeled per year	45 sample days (1080 hours)
Weather years	Weather year 2012
Day sample dependency on year	No dependency. Future years sample different calendar days because electrification and increasing penetrations of renewables will change the days that are most critical to represent.
Perfect foresight	RIO has perfect foresight because all model time periods are simultaneously solved.
Electricity reliability	Determined endogenously with user-specified parameters adjusting the conservatism discussed in section 9.2.5.
Renewable capacity value	Determined endogenously as pre-computed values can have little utility with increasing electrification and changes in system load shape.
Load shapes	Built bottom-up in EnergyPATHWAYS
Generator retirements	Announced retirements are enforced. Otherwise, retirement of generators before the end of their physical lifetimes is optimized with the benefit being savings in fixed O&M.
Generator repower/extension	Solved endogenously. At the end of their physical lifetimes, generators can be repowered at (typically) lower cost than new construction.
Annual carbon emissions constraints	Straight-line path to 5 million tonnes in 2050 for Massachusetts. Proportional carbon constraints across other zones, as s explained in Sections 2.1 and 4.1
Cumulative carbon emission constraints	None applied
Carbon taxes	None applied
RPS/CES	Existing state policy (2019)
RPS/CES qualification	Existing state resource qualifications
Annual resource build constraints	Annual maximum builds by resource group defined with compound growth rates to represent supply-chain constraints

Cumulative resource build constraints	Potential constraints enforced for all renewables with data derived from the NREL ReEDS model.
Fuel prices	Specified exogenously for fossil and with supply curves for biomass and carbon sequestration (sequestration is only available to the Northeast in one pathway that allows pipelines south for CO_2 transport).
Biomass allocation	Determined endogenously between electricity and fuels
Carbon sequestration/use allocation	Determined endogenously between electricity, fuels, and industry

3.1.3 Cost Methodology

The cost estimates for the decarbonization pathways are derived using a suite of methodologies that cover the whole energy system. Table 3 provides a list of the cost calculation methods for each component of the energy system, along with examples.

These costs are presented in the report in two different ways. First shown are gross system cost. This includes capital and operating costs for anything that produces or delivers energy along with incremental costs above the baseline for demand-side technologies. Costs incurred outside of Massachusetts (fossil fuel refining) for energy products consumed within Massachusetts are allocated along with consumption. Second is net system cost, which focuses on differences between gross system costs between two pathways. Here we use the All Options pathway, explained in Section 4, as the comparison point for all net cost calculations.

Not included in the cost estimates presented here are any macroeconomic feedbacks, benefits from avoided climate change, benefits from improved air quality, policy & implementation costs, and employment impacts. The societal costs and benefits induced by decarbonization, including employment and avoided public health damages, were evaluated for each of the pathways from a macro-economic perspective using the IMPLAN model and are presented in the (forthcoming) 2050 Roadmap study.

All costs are assessed on a societal basis. This means, for example, that the cost of biomass in Massachusetts is summed up for each price tier of the biomass supply curve, as opposed to being calculated based on the marginal price of the final tier, as might happen in a market for biomass. Using the societal method is appropriate from a public policy perspective because, in this example, the market profits from biomass growers within the Commonwealth are not a true cost, but rather a cost transfer. The same dynamic exists in electricity markets, where a societal cost approach is also taken. The societal cost here does not include explicit assessments of the different costs across members of society; where public policy is concerned with the distribution and equity of costs and benefits to across society, these impacts are discussed further in other reports within in the Roadmap study.

All cost inputs and outputs in this report are shown in 2018 dollars.

Table 3 List of energy system costs included in this analysis and the basic methods used for each.

Supply/Demand	Fixed/Variable	Method	Costs	Examples
Demand	Fixed	Technology stock	Levelized equipment costs of all energy-consuming equipment in the economy represented at the technology level	Electric vehicles
Demand	Fixed	Generic cost per unit of energy saved	Incremental energy efficiency measure costs. Represents demand-side costs we do not have the technology-level data to support bottom-up.	Industrial energy efficiency measures
Supply	Fixed	Technology stock	Levelized equipment costs of all energy producing, converting, delivering, and storing infrastructure in the economy represented at the technology level	Solar power plants; wind power plants; battery storage; hydrogen electrolysis facilities
Supply	Fixed/variable	Revenue requirement	Projected revenue requirements based on current revenue requirements, anticipated growth levels consistent with scenarios (i.e. growing peak demand) and type of costs (i.e. the costs can be fixed investments or variable costs that can decline with lower demand).	Electricity T&D costs; gas T&D costs
Supply	Variable	Commodity costs	Costs based on exogenous unit cost assumptions	Biomass, fossil gasoline, fossil diesel, natural gas, etc.
Macroeconomic	Various	IMPLAN model	Induced costs and benefits from the energy system transformation	Gross state product; jobs
Macroeconomic	Various	IMPLAN model	Health benefits from improved air quality	Reduced healthcare costs

3.1.4 **Key data assumptions**

Complete lists of data sources are listed in Section 7. Table 4 serves as a summary, focusing on those data inputs of highest impact on the analysis with references to the detailed descriptions. In addition to Section 7, a data input catalog Excel sheet provides many of the electricity and fuels data inputs used in the analysis.

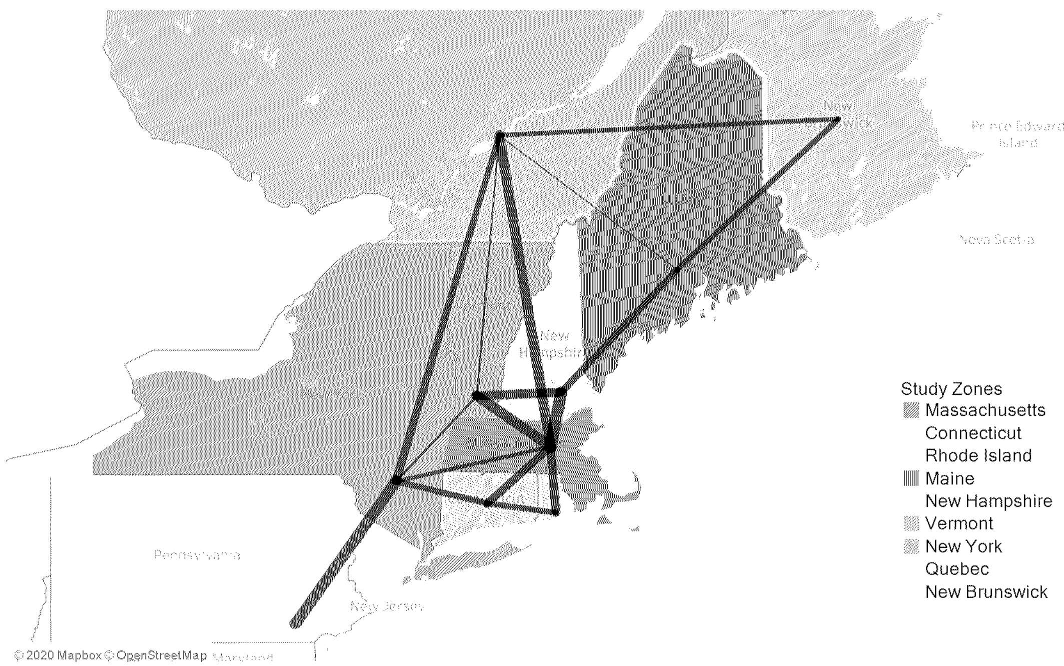
Table 4 Key data assumption summary table.

Data Assumption	Section	Summary
Weather year	7.1	Weather year 2012 is used for presentation of all results. Electricity shapes and T&D estimates were also done for 2011 because it has higher peak HDD and CDD events. Because the 2011 weather year did not directionally change any of the study's conclusions, it is not a focus within the report. Projections of annual average heating and cooling degree days include the impacts of a warming climate as estimated in the U.S. Annual Energy Outlook 2019.
RIO day sampling	7.1	45 sample days each for the snapshot years 2020, 2025, 2030, 2035, 2040, 2045, 2050.
Imported net-zero carbon fuels	7.2	Net-zero carbon hydrogen imports at $20/MMBtu, gas at $30/MMBtu, and liquid fuels at $40/MMBtu. See Section 4.1 for further detail on carbon lifecycle assumptions.
Fuel conversion cost and potential	7.3	Compilation of public techno-economic studies with cost declines observed for most technologies. Data is summarized in the Excel input catalog. Biomass potential from DOE 2016 Billion Ton Report.
Carbon sequestration	7.4	Available in the Regional Coordination pathway at $71/tonne, including transport costs
Building heating costs & performance	7.5	Based on a combination of Mass CEC heat pump database values, NREL's electrification futures study, and Navigant inputs to DOE NEMS model
End-use load shape profiles	7.6	A variety of sources are used. For space heating, in house regressions using Energy Plus building simulations performed by NREL and historical HDD & CDD data by county from NOAA.
Electric & gas delivery infrastructure assumptions	7.7	Escalation or retirement of existing financial stocks based on assumed ratios between peak/throughput growth and revenue requirement growth. Calculations are done by customer class with the average across all classes for electricity growth $205/kW-year.
Generator cost and potential	7.8	Cost and performance based on NREL Annual Technology Baseline (ATB) 2019 with regional cost multipliers by technology. Technology potentials and spur line costs from the NREL ReEDS model (v2018).
Behind-the-meter solar PV	7.9	Behind-the-meter solar growth trajectory was an input assumption rather than an output. Seven gigawatts were assumed to be adopted in Massachusetts by 2050 in all pathways except for DER Breakthrough where this was increased to 16.9 GW.
Flexible end-use load	7.10	Enabled for vehicles, space, & water heating across all pathways. The DER Breakthrough pathway has increased flexible load penetration and vehicle to grid. Existing load-shedding DR programs are maintained in all years.
Inter-regional transmission flow limits and expansion cost	7.11	$5,600/MW-mile within New England and $9,400/MW-mile to Quebec with a low-cost sensitivity (Regional Coordination) assuming $3,300/MW-mile within New England and $4,700/MW-mile to Quebec
Hydro-Quebec operational constraints and expansion cost	7.12	Daily minimum capacity factors of 30% and a maximum hourly ramp rate of 20% across all dispatchable hydro. Ability to shift hydro budgets between seasons. Expansion costs assumed from NREL ATB 2019.
Cost of capital & discount rates	7.13	Societal discount rate 2% real Demand-side: 3-8% real depending on subsector Nuclear 6% real Offshore wind 5% real All other electricity generation 4% real Fuel conversion technologies 10% real
Demand-side sales share assumptions	7.14	Made by assumption and iteration based on supply-side modeling. Varies by pathway.

3.2 Regional representation

The EnergyPATHWAYS (EP) and RIO models were run for each of ten zones: six New England / ISO-NE states plus four neighboring regions (New York, Quebec, New Brunswick, and rest of the U.S.). A map of the analysis geographies is given in Figure 6. Transmission flows and capacity expansion were economically determined across 17 transmission paths in the region. Massachusetts is interconnected to five neighboring states (CT, RI, VT, NH, NY) plus direct interties with Quebec.

Figure 6 Study regions used in the EnergyPATHWAYS and RIO models. Final energy scenarios were produced for each colored region, along with "rest of U.S." to establish boundary conditions for NY. The transmission topology used in the RIO model is shown in the map where the width of each black line represents 2020 transmission transfer capability. The large number of zones external to Massachusetts were represented because of the importance of inter-state and cross-border interactions when all states are pursuing deep decarbonization.



For the U.S. zones, EP and RIO scenarios were developed specifically for this study. In Quebec and New Brunswick, electricity load shapes developed in EP in 2018 as part of the North American Renewable Integration Study (NARIS), conducted in partnership with NREL,[20] were used.

For Northeastern states, each pursuing aggressive climate policy in an interconnected system, the regional context is essential for understanding any single state. This is becoming more critical over time as renewables emerge as the leading strategy in electricity decarbonization because of the benefits of geographic diversity in a high renewables electricity system. Northeastern states have a common set of resources to select from, and potentially to compete over, when decarbonizing (for example, imports from Quebec, sites for building wind generation, or zero carbon fuel imports). Thus, the availability and robustness of any strategy depends, in part, on what other states are doing.

[20] National Renewable Energy Laboratory, North American Renewable Integration Study, https://www.nrel.gov/analysis/naris.html

Assuming collective action generally creates boundary conditions in decarbonization modeling exercises that increase its difficulty.[21] For example, one state could decarbonize by making fuels with any available biomass in the region but would encounter problems if all the states attempt to implement the same strategy. Similarly, one state might be able to run a deeply decarbonized economy by building out offshore wind in only the richest, most accessible, least expensive lease areas, but if every state in the Northeast sets similar renewable generation goals, that low-hanging fruit would be quickly exhausted.

States must assume that eventually all neighboring jurisdictions share common targets. This removes logical inconsistencies in the energy system transition and helps ensure any decarbonization strategies do not inadvertently depend on collective inaction (as would be the case if a strategy was unable to be universalized). For this reason, this analysis assumed the percent reduction between 2020 and 2050 in energy and industrial emissions across all zones matched that of Massachusetts. The presumption here is that targets will eventually coalesce around net zero by 2050, even if most Northeastern state policies currently focus on 80x50 targets.[22]

3.3 Uncertainties and caveats

Section 2.3 described the value of creating long-term pathways. Here we describe some general uncertainties that apply to any pathways exercise, plus others that apply specifically to Massachusetts. Instead of returning to these caveats multiple times in the presentation of the results, they are enumerated here once for the reader.

3.3.1 **General uncertainties**

The first important point is to reiterate that none of the pathways in this study are forecasts. The energy system of the future will inevitably turn out differently than whatever is analyzed here. Aspects that we may not have considered at all will influence how the system evolves in yet unimagined ways. As a thought experiment, consider what strategies a decarbonization plan formulated in the year 1990 would have emphasized; the world's first offshore wind farm, a key strategy presented in this work, was still a year away from construction in Denmark. Clearly, the value of this study lies not in creating a rigid blueprint as the basis of an unvarying 30-year plan, but in informing the public and decision-makers based on the state of current knowledge. Pathways have been used most successfully in recent years through a process of periodic updating—a dynamic in which near-term decisions are informed by the long-term perspective, while the long-term perspective is continually updated based on newly emerging information.

Second, decarbonization pathways studies by their nature focus heavily on the physical transitions of technology and infrastructure but ignore many human and institutional factors because of the difficulty of quantifying them and incorporating them into mathematical models. For example, this study assumes a smooth and continuous growth in the sales of new electric transit buses. The transit authorities in the region, such as the Massachusetts Bay Transit Authority (MBTA), have in the past tended to purchase buses in large orders, retiring and replacing as much as a third of their fleets in a single procurement. Because they were not

[21] Not considered here is the fact that learning—technical and institutional—is likely to accelerate with collective action, leading to reductions in the cost of energy system transitions. This benefit is difficult to quantify and is not factored into the analysis.

[22] Because Massachusetts remains this study's focus, we did not quantify non-CO2 and land related emissions across each zone in order to determine whether each zone achieved net-zero.

included in the analysis, these factors are not emphasized in this report, but this does not diminish their importance.

Similarly, equity and distributional impacts between pathways are not quantified in this report. The energy data used to populate the EnergyPATHWAYS and RIO models are primarily state-wide aggregates, and as a result, the models can quantify impacts on the average household, but not, for example, households in a given zip code. Qualitative discussions of the distributional impacts are brought into the discussion where possible, but further discussion of the interactions between decarbonization policies and equity are primarily addressed in the 2050 Roadmap report, rather than this document.

As noted in Section 2.3, one valuable result from modeling a set of pathway sensitivities is the identification of commonalities between pathways. The common findings for the set of eight pathways run in this report are discussed in section 6.1. That said, the sensitivities that were modeled are by no means exhaustive, and the dimensions of the problem that are both important and uncertain are far more numerous than the number of pathways it was feasible to explore. With more time and computational resources, additional dimensions could be explored.

3.3.2 Massachusetts-specific uncertainties

The novelty of the energy system transformation imagined across the U.S. in this analysis requires many assumptions to be made in the modeling that are necessary but uncertain. Table 5 lists some of the largest uncertainties and the ways this analysis has tried to deal with them. The uncertainties themselves motivated the design of many of the pathways discussed in the next section.

Table 5 Key areas of uncertainty in modeling decarbonized energy systems in Massachusetts and how they were addressed in the pathway design.

Uncertainty	Explanation	How addressed in modeling
Ability to site renewables	New England has been one of the most difficult locations in the U.S. to site renewables due to high population densities, expensive and disconnected land for development, and strong opposition to disturbances to natural lands.	Onshore wind in New York and New England was given a cost multiplier reflecting a siting premium in the region. Solar was assumed to be more expensive to develop in the southern New England states (Connecticut, Rhode Island, and Massachusetts). The cost scalers were based on NREL and EERE solar and wind reports.[23]
Ability to site transmission	The Northeast has seen many transmission projects delayed or canceled due to siting challenges. The ability to build transmission to connect renewables to load and to help balance renewables through geographic diversity are essential to scenarios with high wind and solar penetrations.	Transmission projects that have been built in the region are consistently some of the most expensive in the country. Pathways use pessimistic interregional transmission costs to discourage strategies that over-rely on potentially unachievable transmission builds.
Cost of offshore wind	Both near-term procurement contracts and 30-year techno-economic estimates for offshore wind costs have fallen dramatically in recent years, despite large challenges developing initial projects in the Northeast. Europe has proven that affordable offshore wind is possible in the right environment, but how and when that experience will translate into inexpensive offshore wind in New England is still uncertain.	Given the importance of offshore wind for the region, this uncertainty was tested in a pathway that used higher offshore wind cost and lower potential & performance.

[23] Solar cost multiplier of 1.2x derived from: National Renewable Energy Laboratory, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018, November 2018, https://www.nrel.gov/docs/fy19osti/72399.pdf
Onshore wind cost multiplier of 1.8x derived from: U.S. Office of Energy Efficiency & Renewable Energy, 2018 Wind Technologies Market Report, https://www.energy.gov/eere/wind/downloads/2018-wind-technologies-market-report

Electricity operations in high wind and solar systems	The challenges arising in high renewable systems have been well documented (Figure 40). While technical solutions abound, exact cost and implementation details may not be known in advance.	These concerns are primarily addressed through careful design of the modeling tools used (section 3.1) and ensuring that the designed electricity system is robust to periods in the historical weather record that correspond to very low renewable production. Extensive discussion of the methods by which the envisioned systems balance supply with demand are provided in section 5.4.3.
Customer adoption of electric and efficient technologies	Demand-side adoption of efficient and predominantly electric technologies are important pillars of energy system decarbonization. Yet, this adoption depends on customer decisions, which can be influenced through policy mechanisms such as incentives and mandates, but ultimately not controlled. This means any energy system transition is partially predicated on customer behavior regarding energy use, and not just policy to shape energy supply.	Exploration of customer uptake rates at different levels of incentives and in response to a variety of regulatory schemes are explored in the Buildings and Transportation technical reports. In this work, we studied a high pipeline gas scenario and low efficiency adoption scenario, both of which test alternative demand-side outcomes.
Load shapes for electric heating	Predicting future peak load from heating is sensitive to a set of uncertain factors. These include: (1) future heat-pump COPs at very low temperatures; (2) temperature, solar gain, and wind-speed distributions across the state; (3) heat-pump sizing practices; (4) use of supplemental electric heating; (5) customer set-points and willingness to participate in flexible load programs; and (6) improvements to building shells (infiltration, insulation, and thermal mass).	This analysis uses a sophisticated set of regressions developed in the NREL Electrification Futures Study.[24] with recent updates to low temperature heat-pump performance. A range of assumptions were tested on HVAC flexibility as well as building shell efficiency. Finally, comparison is done to Quebec load shapes, which because its heating is primarily electric today, can serve as a good empirical benchmark—despite other differences (half the number of households in New England; primarily electric resistance heating; and colder average climate)
Flexibility of end-use loads	Building and transport electrification applications are unique in the magnitude of inherent energy storage available (chemical in batteries and thermal in space and water heating). This means shifts in the timing of electricity consumption are possible with almost no impact to the customer and large cost savings. However, participation in these programs, the degree to which load can be shifted without affecting service, and exact systems for control are all uncertain.	All pathways embed a moderate amount of flexible end-use load. The value of major breakthroughs in end-use load flexibility was quantified in the DER breakthrough scenario. Flexible load assumptions are provided in Section 7.10.
Electric distribution cost increases from load growth	The cost impact of load increases on distribution systems is a hyper-local question that varies by circuit. Therefore, exactly how a doubling of load will impact the distribution revenue requirement is difficult to quantify when analyzed at a state level.	The approach taken in this study is to scale existing revenue requirements with increases in peak load by feeder (residential, commercial, & industrial). We assume a doubling of peak leads to an 80% increase in revenue requirement, which translated to an average distribution growth cost of $205/kW-year. This scaling coefficient of 0.8 may be higher or lower and cost results are discussed with this uncertainty in mind.
Gas distribution cost savings when gas throughput declines	All decarbonization scenarios resulted in declines in gas distribution pipeline throughput. The declines are most dramatic in scenarios with high building heating electrification. The cost estimation problem here is the inverse of electricity distribution problem above—as gas throughput declines it is uncertain how quickly the pipeline revenue requirement could be reduced. This question is also hyper-local and depends on the	As with electricity distribution, the geographic granularity of this study is insufficient to quantify all the relevant factors, nor can some of the key questions, like the geographic patterns of customer adoption, be definitively forecasted. Instead, pipeline revenue requirements can shrink using a revenue requirement scaling similar to electricity distribution, but only at a very slow rate

[24] National Renewable Energy Laboratory, Electrification Futures Study, https://www.nrel.gov/analysis/electrification-futures.html

	geographic patterns of electrification, the depreciation of existing assets, and safety considerations.	(assumed 50 year book-life). This approach recognizes the fact that large portions of the gas system will need to be maintained for a long time, even assuming rapid electrification.
Low-carbon fuels	There is significant uncertainty in the availability, cost, and life-cycle impacts of low-carbon fuels (including bio- and synthetic liquid fuel and gas substitutes). In addition, should such feedstocks, processes, and life-cycle considerations be determined it is still unclear how these considerations would be incorporated into Massachusetts' GHG Inventory.	Availability and cost of biogenic-based fuels are bounded by the US DOE's Billion Ton Study. RIO uses the domestic production of synthetic fuels from, for example, captured carbon and electricity-derived hydrogen when economically competitive against alternative emissions reduction strategies. As a simplification, such drop-ins are considered to have a net-zero carbon emissions profile. This assumption is discussed further in Section 4.1 of this report and in Appendix Z of the Roadmap Report, alongside implications for policy and GHG accounting frameworks.
Impact of COVID-19	The COVID-19 has had large impacts on the demand for energy services in 2020.	The impacts of COVID-19 are not estimated as part of this analysis. Much of the modeling work was conducted in early 2020 when the impacts of COVID-19 were still emerging. This modeling work was not revisited because: (1) The impact from COVID-19 on energy consumption is still not precisely known at time of publication; and, (2) the impacts from COVID-19 are not expected to change the long-term findings of the analysis.

4 Pathway definitions

We explored eight net-zero emissions pathways for the Northeast. The analysis started by defining a pathway we call “All Options,” which was created using assumptions found compatible with deep decarbonization in previous studies. Pathways are varied one dimension at a time in order to isolate the impact of specific factors. The eight pathways are described in Table 6. The dimensions of variation studied include:

- Behind the meter (BTM) solar and flexible end-use load explored in the “DER Breakthrough” scenario;
- Rates of building and industry electrification explored in the “Pipeline Gas” scenario;
- Deployment of energy efficiency explored in the “Limited Efficiency” scenario;
- Ease of transborder infrastructure development explored in the “Regional Coordination” scenario;
- Availability of gas thermal power plants explored in the “No Thermal” scenario;
- Cost and potential of offshore wind in the “Offshore Wind Constrained” scenario;
- And, the availability of non-renewable inputs to the 2050 energy system (excludes nuclear & fossil) in the “100% Renewable Primary” scenario.

Aside from the differences highlighted in Table 6, data and assumptions are shared between all pathways. For example, all scenarios meet the same demand for energy services,[25] assume the same cost for demand-side technology adoption, and meet the same emissions targets. Data inputs are from public sources and are provided along with important assumptions in Section 7. The assumption of consistent service demand is of particular importance as a design criterion as a way to show the feasibility and affordability of a technological transition to deep decarbonization. With this in mind, energy conservation and lifestyle change could significantly ease parts of the transition.

For several pathways listed in Table 6, descriptors “High,” “Medium,” and “Low” are used as a shorthand for describing the assumptions. This shorthand is used due to the complexity of the inputs, which are difficult to describe succinctly in one table row. For example, different heat pump adoption rates are specified for space and for water heating, each separately for residential and commercial customers. The detailed sales share inputs and resulting stock shares are provided for Massachusetts in Section 7.14.

An important clarification is that the pathway titled “All Options” pathway is not meant to be interpreted as an endorsed pathway for the Commonwealth. Indeed, it is not lowest cost or necessarily preferred along other dimensions. Instead, the role of “All Options” is as a point of comparison between different pathways—a role that is played by a reference or baseline scenario in most studies. This study is not an investigation of whether Massachusetts should decarbonize,[26] given that the net-zero target is current state policy; thus, a reference scenario, while it was developed, is not a focus within the results.[27] Thus, the seven other pathways represent deviations from All Options meant to explore how technological evolutions could ease the transition to a net-zero future or how certain constraints or secondary goals could make that transition different, if not more

[25] For example, demand for maintaining a comfortable indoor temperature can be met using any combination of fossil energy (e.g. natural gas-fired furnaces), electric energy (e.g. heat pumps), and efficiency measures (e.g. air sealing and weatherization).

[26] This report does not discuss the quantitative benefits from avoided climate damages or the cost of climate adaptation, and thus, gives an incomplete picture of the societal net benefits of decarbonization. Many of these elements are discussed in the Roadmap Study.

[27] The reference scenario represents a baseline loosely based on the 2019 U.S. Annual Energy Outlook. Carbon emissions are not capped, and only minor changes are assumed to occur on the energy demand-side. For example, electric vehicle adoption is much lower than assumed in the decarbonization pathways.

difficult. The Pipeline Gas pathway assumes low electrification of gas applications in buildings and industry (e.g. water heating). Other types of electrification are still assumed, for example heat pumps still replace fuel oil in buildings. The Pipeline Gas pathway does not pre-constrain the composition of gas in the pipeline (e.g. biogas or hydrogen) but instead solves for this mix in the supply-side optimization in RIO, which is subject to the emissions constraints.

Table 6 Scenario matrix contrasting the eight net-zero emissions pathways. The "All options" scenario serves as a common point of comparison across the seven variations that test key uncertainties or explore alternate strategies. The differences from the All options scenario are highlighted in orange. Each of the qualitative descriptions (e.g. high vs. low) are defined in Section 7.

	All Options	DER Breakthrough	Pipeline Gas	Limited Efficiency	Regional Coordination	No thermal	Offshore Wind Constrained	100% Renewable Primary
Mass BTM solar in 2050	7 GW	17 GW	7 GW	7 GW	7 GW	7 GW	7 GW	7 GW
Flexible end-use loads	Medium	High w V2G	Medium	Medium	Medium	Medium	Medium	Medium
Building & industry electrification	High	High	Low electrification of pipeline gas applications	High	High	High	High	High
Energy Efficiency	High	High	High	Reference efficiency across buildings, industry and transport	High	High	High	High
Captured CO_2 Export	No	No	No	No	Yes	No	No	No
Intra-regional transmission cost	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec	$3,300/MW-mile within New England; $4,700/MW-mile to Quebec	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec	$5,600/MW-mile within New England; $9,400/MW-mile to Quebec
New gas power plants	Disallowed in Massachusetts	Disallowed in Massachusetts	Disallowed in Massachusetts	Disallowed in Massachusetts	Disallowed in Massachusetts	Disallowed everywhere	Disallowed in Massachusetts	Disallowed in Massachusetts
New offshore wind power plants	Economic, ATB low	Economic, ATB low	Economic, ATB low	Economic, ATB low	Economic, ATB low	Economic, ATB low	30 GW Northeast Cap w ATB mid	Economic, ATB low
New nuclear power plants	Disallowed	Disallowed	Disallowed	Disallowed	Disallowed	Disallowed	Economic[28]	Disallowed
Existing nuclear	Maintain	Maintain	Maintain	Maintain	Maintain	Maintain	Maintain	Retire
Use of fossil fuels	Constrained by emissions	Constrained by emissions	Constrained by emissions	Constrained by emissions	Constrained by emissions	Constrained by emissions	Constrained by emissions	No fossil fuels in 2050

[28] A base assumption of 'no new nuclear build' in the Northeast was implemented due to the perceived difficulty of siting new nuclear and noting it was not a necessary part of the solution in test runs. However, the study team also had interest in a 'nuclear breakthrough' scenario. Due to limitations on the total number of pathways we could study, the decision was made to add economic nuclear to the Offshore Wind Constrained scenario. The underlying assumption was that if any scenario would best highlight the potential role for nuclear, it was one in which offshore wind was limited.

Creating the eight pathways in the analysis was an iterative process that started with observing early model results from the All Options pathway and soliciting feedback on the list of uncertainties in Section 3.3.2. For example, after noting the importance of offshore wind to New England in early runs, the "Offshore Wind Constrained" scenario was devised to test how increases in offshore wind cost and decreases in potential would impact the results. Other pathways were developed in response to key questions on the minds of stakeholders or state policymakers, such as the role for gas in buildings and power plants or the feasibility of an energy system in 2050 that uses zero fossil fuels.

The eight pathways are themselves not exhaustive and leave some of the uncertainties described in Section 3.3.2 as subjects for future work. However, the primary goal in the pathways design was accomplished, which was to perturb the All Options pathway in various ways (some making decarbonization more challenging, others less), in order to observe the commonalities between all pathways that achieve Net Zero. The use of pathways is discussed further in Section 2.3.

4.1 Energy & Industrial CO_2 emission constraints

The emission of CO_2 from the energy and industrial sectors represents the largest, but not the only contributors to economy-wide net-zero GHG emissions. The companion *Non-Energy Technical Report* found that emissions of fluorinated compounds, fugitive methane, and other non-combustion emissions could be limited to 4.6 $MtCO_2e$ in 2050. Meanwhile, the Land-Use study analyzed how natural and working lands in the Commonwealth can help remove residual emissions in 2050 in order to bring Massachusetts towards a net-zero economy. However, because the Massachusetts GHG Inventory (a matter of law) is currently a gross emissions accounting framework, this report makes no attempt to resolve how biogenic sequestration of carbon in natural and working lands might impact a net-zero emissions accounting. During the framing of this study, EEA undertook a process to seek public comment on setting a gross emissions limit in support of net-zero emissions at an 80%, 85%, or 90% reduction from 1990 emissions levels by 2050. While the Secretary of EEA ultimately determined that 85% was the most appropriate gross emissions reduction goal, the timing considerations required that modeling for this study needed to be underway prior to that determination. Thus, the project team was instructed to target the upper bound of those options (90% or 9.5 $MtCO_2e$). Leaving a set-aside for the 4.6 $MtCO_2e$ from the non-energy sector in 2050, this left the energy and industrial sectors with a reduction target of no more than 5 $MtCO_2e$ in 2050. Interim years (e.g., 2030, 2040) were set as a straight-line reduction from the previously established 2020 emissions limit to the 2050 modeling target.

The emissions accounting framework used in this study is based on the system used for the Massachusetts GHG inventory but differs in several ways based on the net-zero framing.[29] Emissions rates for electricity generators were benchmarked against the factors assumed in the 2017 MassDEP GHG Emissions Inventory; this approximates, but does not precisely replicate the interstate emissions accounting system MassDEP uses. Within Northeastern states, imports of net-zero carbon liquid or gaseous fuels was an option in the model as a replacement for fossil fuels in applications such as aviation or building heating. Combusting these biomass- or electricity-derived synthetic fuels would result in positive gross carbon emissions within Massachusetts, but the carbon in these fuels is assumed to come either from the atmosphere or from captured carbon that would

[29] Until very recently, Massachusetts GHG targets were based on a gross emission reduction target. The assumptions made in this analysis were made for expedience and do not resolve all questions or endorse a specific methodology in the inventory moving forward.

have otherwise been emitted. Thus, their use is assumed to not result in any net emissions. Use of biomass harvested within Massachusetts is similarly assumed to be carbon neutral, a simplification of the complex, long-term carbon fluxes associated with active forest management and growth which are addressed in more detail in the *Land Sector Technical Report*. Auxiliary emissions from biomass harvest and bio-fuel production is an important consideration, but is not addressed in this study for two reasons: (1) all agricultural and industrial emissions are already accounted for separately, thus the use of life-cycle assessment (LCA) factors for biofuels would be double-counting; and (2) because the entire economy is decarbonizing towards net-zero, the LCA factors themselves would trend down over time. Appendix Z of the Roadmap Report discusses the impacts of low-carbon fuels, especially biofuels, on Massachusetts' current GHG Inventory, as well as implications for how life-cycle carbon emissions and non-GHG externalities might be incorporated into an anticipated set of updates to adapt the Inventory to a net emissions framework. Specific aspects of these fuels, such as feedstocks and applications, is discussed throughout Section 5 and in detail in Section 5.5 of this report. How Massachusetts or other states and regions that produce, import, or export zero-carbon fuels should measure and report sequestration or emissions associated with production, transportation, and utilization of these fuels is highly complex. This report does not attempt to make recommendations for such accounting procedures.

5 Results

The results of the modeling are described below in six subsections, beginning with an overview of the 2050 energy system, followed by a detailed examination of emissions, energy end uses, electricity, fuels, and costs. In most cases, the results focus on Massachusetts only, but regional snapshots are also provided. Supplemental results figures and tables are provided in Section 8. For clarity and economy of space, not all pathways are shown in all figures in this section, but in general the full set can be found in the supplemental results.

This section focuses on describing the technical results of the modeling with a minimum of commentary. The subsequent section discusses the main conceptual findings revealed by the modeling. The discussion section identifies and elaborates on commonalities and contrasts found across cases, referring back to the results presented below.

5.1 Energy system overview

The 2050 energy systems that reach a net-zero E&I CO_2 target look dramatically different from today's. A series of "Sankey diagrams" (Figure 7) provide an overview of this transformation, and illustrate at a high level how energy is produced and consumed in a net-zero system in 2050. Sankey diagrams show the flow of energy through the economy, with the left-hand side showing primary energy supplied within Massachusetts, and imports into Massachusetts, and moving through various conversion processes, such as electricity generation, to end-use consumption in buildings, industry, and transportation on the right-hand side.

The first diagram shows the current energy system of Massachusetts in 2020. Almost all energy is provided by imports of petroleum or natural gas. Natural gas use is split between buildings and electricity generation. Electricity is primarily consumed in buildings. Transportation consumes most of the petroleum, but some is consumed in buildings (distillate oil-based heating) and some in industry. Industrial energy demand in Massachusetts is small compared to consumption in buildings and transportation but has the most diverse set of final energy supplies, requiring electricity, liquids, asphalt, pipeline gas, and steam.

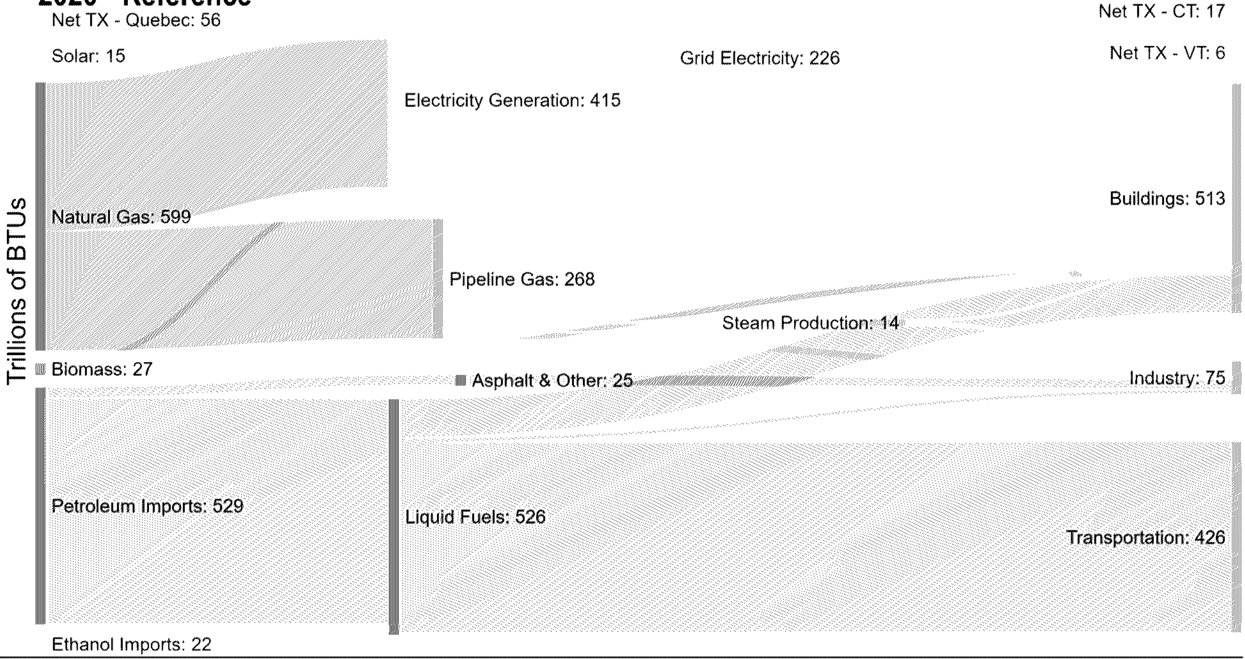
The second diagram shows the All Options net-zero pathway in 2050, which has dramatically different energy flow patterns. Overall, energy demand has decreased, electricity dominates end uses, and the source of primary energy has shifted away from fossil fuels and toward renewables. Final energy demand in buildings and transportation has decreased by about half due to same-fuel efficiency improvements plus the efficiency benefits that come from electrification.

The process of electrification has created new connections that do not exist at a significant level in the current system (i.e. electricity in transportation), and roughly doubles the amount of final energy demand that must be supplied by electricity. Electricity also has an additional new role as an intermediate energy carrier used in the production of steam and hydrogen.

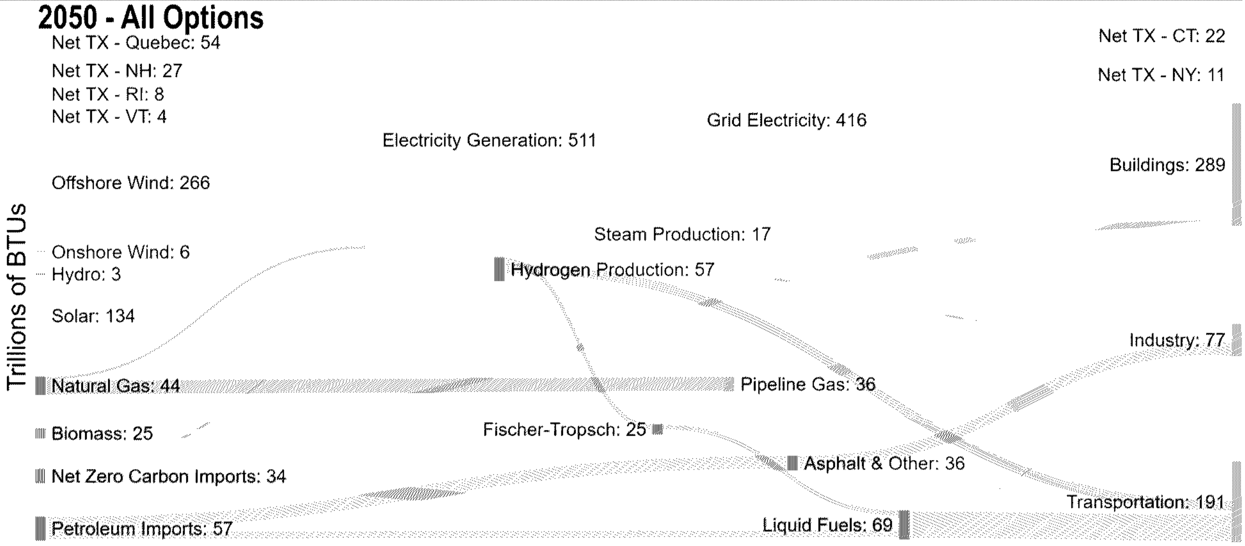
Hydrogen emerges as an important final energy carrier in transportation, with small amounts also used in industry. The source of electricity has shifted away from natural gas and towards solar and offshore wind. Both net imports and net exports of electricity have increased, indicating increased regional interdependence. Both natural gas and petroleum are still imported but decreased to roughly one-tenth of today's quantity, with new carbon neutral imported fuels taking their place in some applications. In-state biomass use has not grown but has shifted towards fuel production rather than electricity generation. Liquid and gaseous fuels are still important energy carriers (for example, in aviation), but due to electrification and efficiency the quantity of fuels required is greatly reduced.

Figure 7 Energy system Sankey diagrams for Massachusetts show the flow of energy from primary sources or imports (left) through conversion processes (middle) to final energy demand or exports (right). The width of each line is proportional to the energy flow with units shown in TBtus. Diagrams are shown for the 2020 energy system and for the eight decarbonization pathways in 2050, across three pages. The difference in line width between flows into a node and out of a node represents energy losses during conversion or delivery. To improve readability, annual flows smaller than 3 TBtus are excluded—for example, the small amount of LPG used in buildings in 2050 does not appear. Net annual transmission flows from/to neighboring regions are shown across the top of each figure and abbreviated "TX". In the Pipeline Gas and 100% Renewable Primary pathways, hydrogen is produced from electrolysis and some of it is used later to generate electricity; only the net flow is shown (in these pathways more hydrogen is produced than is consumed in electricity).

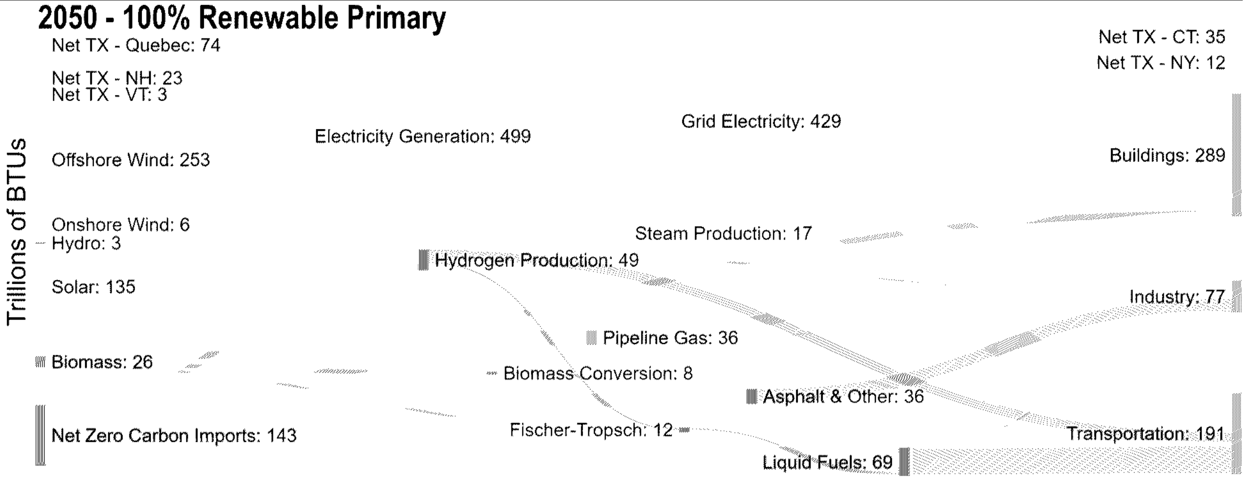
2020 - Reference



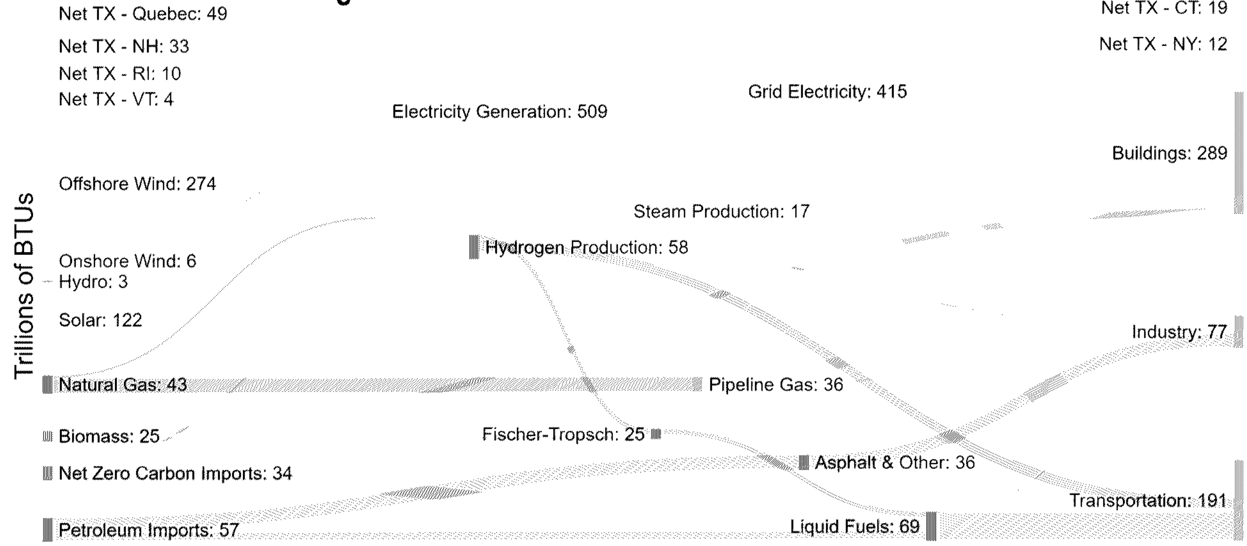
2050 - All Options



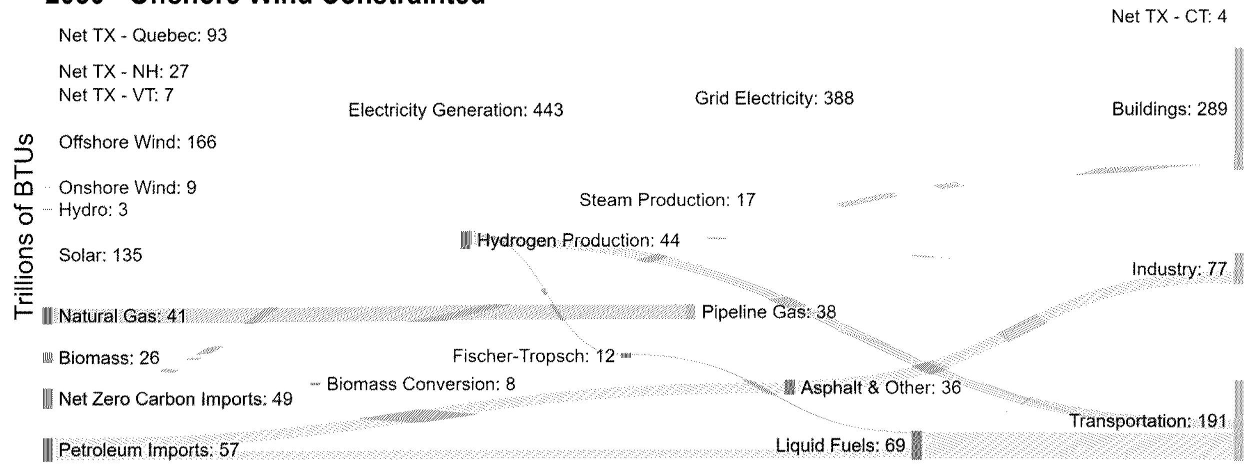
2050 - 100% Renewable Primary



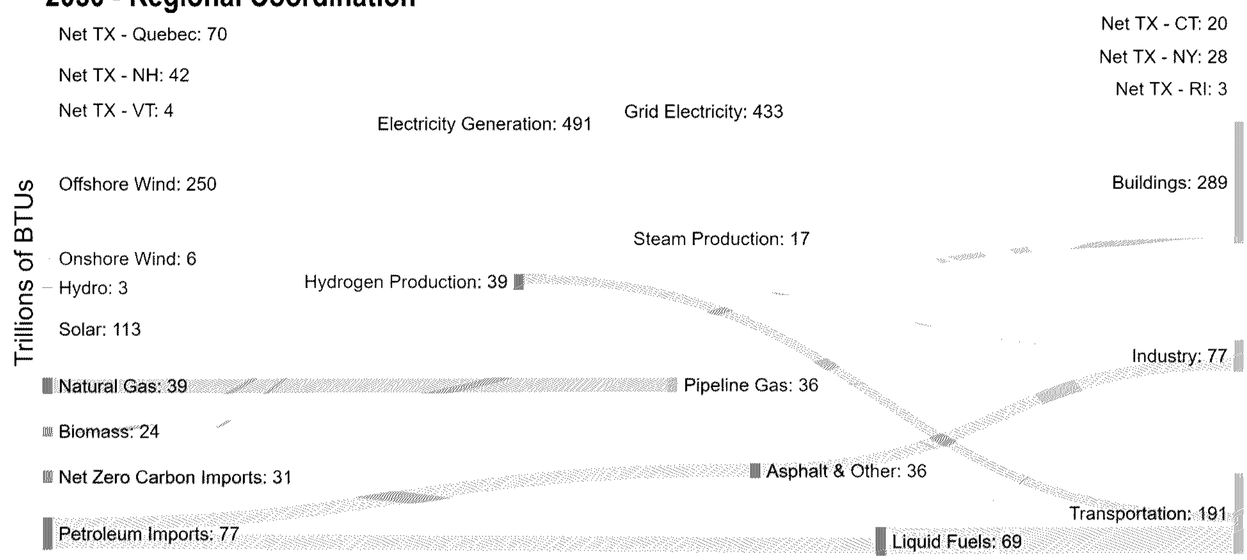
2050 - DER Breakthrough



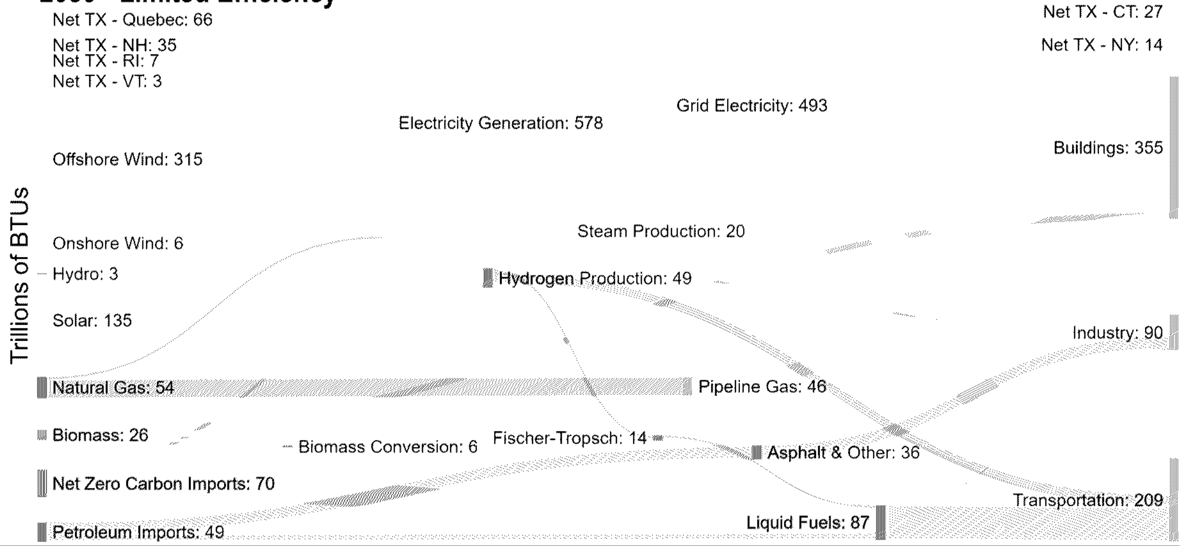
2050 - Offshore Wind Constrainted



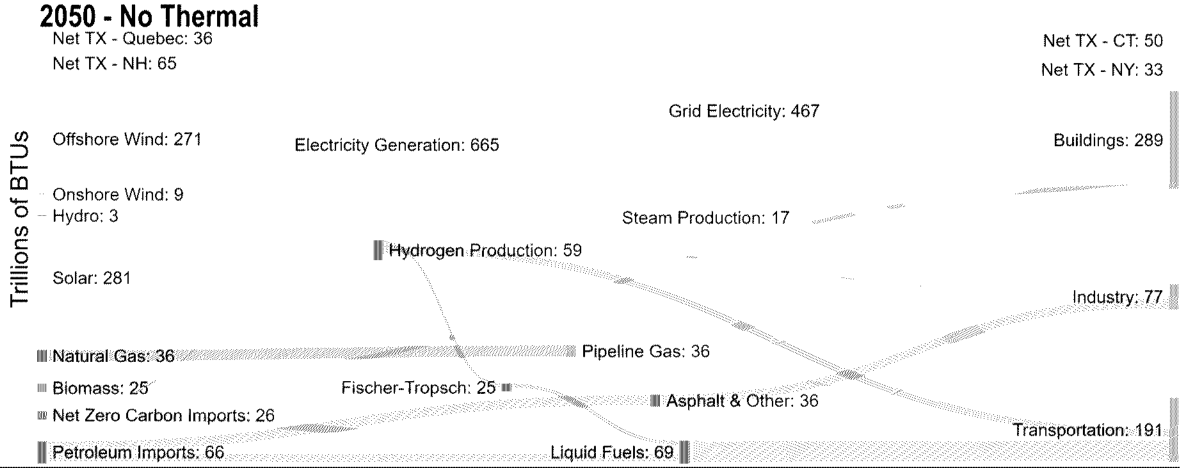
2050 - Regional Coordination



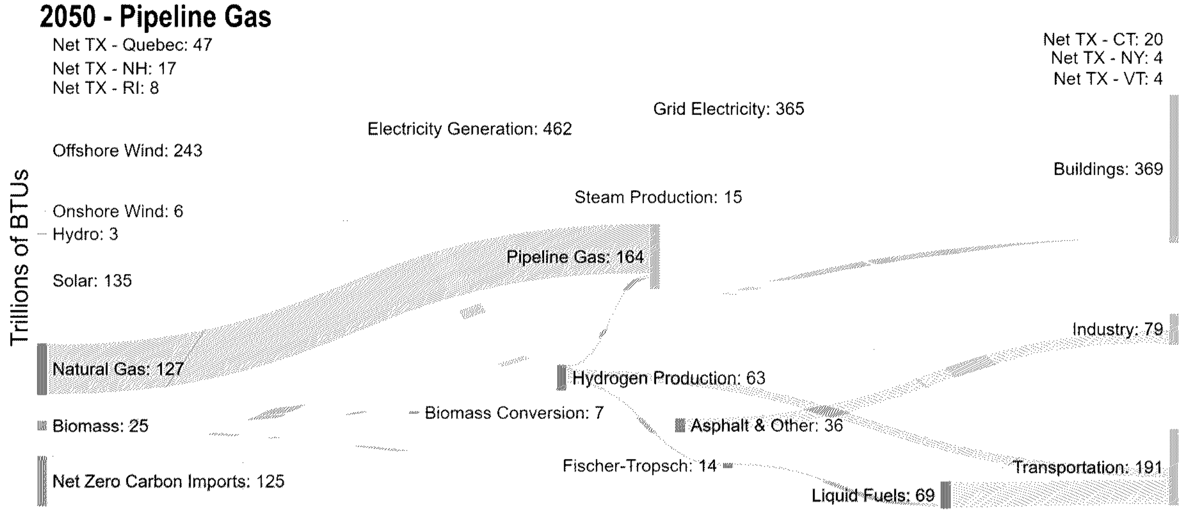
2050 - Limited Efficiency



2050 - No Thermal



2050 - Pipeline Gas



Other pathways can be described based on their differences from the All Options pathway. The bottom diagram on the first page shows that the 100% Renewable Primary pathway eliminates all fossil fuel imports and replaces them with carbon-neutral liquid and gaseous imports (hydrogen and pipeline gas). The top diagram on the second page of the figure shows the DER Breakthrough pathway, which is quite similar to the All Options pathway when viewed with the energy flows being highly aggregated. The major impacts of this pathway are a shift away from ground-mounted solar and towards rooftop PV, as well as significant electricity distribution savings from the operations of flexible load (both of which are discussed in detail in the following sections). The next figure shows the Offshore Wind Constrained pathway, which compensates for less offshore wind with greater net electricity imports. The bottom diagram with the Regional Coordination pathway shows expanded net imports from some zones, such as New Hampshire, and net exports to others, such as New York. As a result, in-state solar and wind are slightly reduced. Biomass is also used to make hydrogen for transportation fuel and the discarded carbon is then captured and exported for sequestration.

The third page of Sankey diagrams starts with the Limited Efficiency pathway at the top. The final energy demands for buildings, industry, and transport are all higher than the All Options pathways because of the lower amounts of efficiency. This has upstream implications of various kinds. The two main ones are greater electricity demand and an increase in both offshore wind and imports to supply it, and a doubling of carbon-neutral fuel imports. These incremental fuel imports are primarily required to supply a less efficient aviation sector and the carbon constraints preclude additional fossil imports. The middle diagram shows the No Thermal pathway, which is the only pathway not to use any fuel (gas or liquid) in generating electricity. As a result, the amount of solar PV in Massachusetts has increased significantly, and so has renewable curtailment.[30] The final pathway is Pipeline Gas, which is distinguishable by the large amount of gas consumed in buildings (~50% of final demand). The gas in the pipeline is a blend of imported carbon-neutral gas, imported fossil natural gas, and hydrogen from electrolysis. Natural gas imports are 2.9x larger than in the All Options pathway and the emissions budget is met by eliminating all fossil petroleum imports and minimizing gas use in electricity. An alternative pathway would be to compensate for higher pipeline gas use with a higher blending rate of carbon-neutral gas; however, this was found to be more costly given the difference in cost between natural gas relative and other refined petroleum products.

Often the carbon emission implications can be intuited from a Sankey diagram, but can't be definitively known, since the deployment of strategies that capture or sequester carbon are not shown. For example, asphalt used in construction is accounted for as an energy flow, but because the asphalt is not combusted, it results in no CO_2 emissions. The carbon accounting of the energy systems shown in the Sankey diagrams is therefore spelled out in the next section.

5.2 Emissions

5.2.1 Massachusetts CO_2 emissions

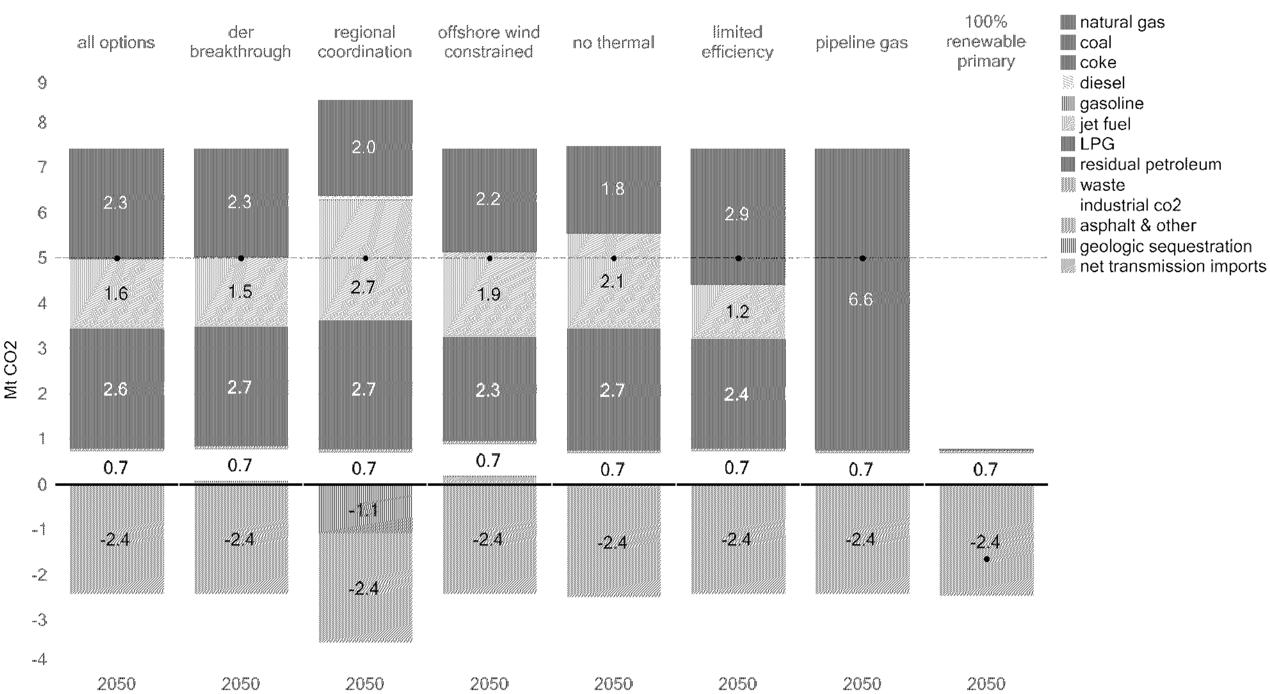
All eight pathways were successfully driven to reach the energy and industrial emissions target of 5.0 Mt CO_2, as can be seen in Figure 8. How the emissions target was derived can be reviewed in Section 4.1. Values above the x-axis represent fossil CO_2 emissions in-state, or consumption-based allocation of electricity emissions that occur out-of-state. Values below the x-axis represent negative CO_2 emissions, either in the form of carbon sequestered in asphalt, lubricants, and other products that consume petroleum products without combusting them or as CO_2 captured in-state and exported out-of-state to be sequestered geologically. Negative emissions into natural and working lands (e.g., sequestration into trees and wetlands), either in-state or out-of-state in

[30] Can be seen by comparing the size of 'Electricity Generation' to the energy that flows into 'Grid Electricity'. Note that the 2020 reference case also shows this discrepancy, but in this case, it is due to efficiency losses in thermal power plants.

the form of an offset credit are discussed in the Land-Use Technical Report and the Roadmap Study Report, but are not included in the modeling featured in this report.

In the All Options pathway, residual emissions—primarily from natural gas, jet fuel, petroleum, and industrial processes—sum up to 7.4 Mt CO_2, from which 2.4 Mt from sequestration in asphalt is subtracted to yield 5.0 Mt. The DER Breakthrough, Offshore Wind Constrained, No Thermal, and Limited Efficiency pathways have only minor differences from the All Options emissions profile. Three other pathways are significantly different from All Options. The Regional Coordination pathway creates emissions space for additional use of fossil fuels by exporting just over 1 Mt CO_2 for sequestration out-of-state. As noted in the scenario matrix (Table 7) this was the only pathway with the option of exporting CO_2, because it was assumed that building regional CO_2 pipelines would be difficult.

Figure 8. Annual energy and industrial emissions for Massachusetts in 2050 for all pathways. The net emissions constraint (5.0 Mt) is shown with a solid black line. All pathways meet this constraint, and the 100% renewable primary scenario exceeds the target, with negative emissions of -1.7 Mt CO_2 per year. The area above the x-axis shows gross emissions from combustion of fossil fuels and industrial processes, and the area below the x-axis shows biogenic carbon in asphalt that ultimately ends up sequestered in landfills. In the regional coordination scenario, CO_2 that is captured and exported out-of-state for geologic sequestration constitutes an additional source of negative emissions.



Another pathway with notable differences is the Pipeline Gas case, in which, except for industrial CO_2 emissions from lime production,[31] all emissions are from natural gas, with gross emissions of 6.6 Mt. As in other cases, the net emissions target is met when carbon sequestration in products (bio-asphalt) is subtracted. Finally, the 100% Renewable Primary pathway exceeds the emissions reductions required by eliminating all fossil fuel emissions (no fossil fuel is used anywhere in the economy) so that the only gross emissions come from industrial processes. When this is combined with negative emissions from sequestration associated with

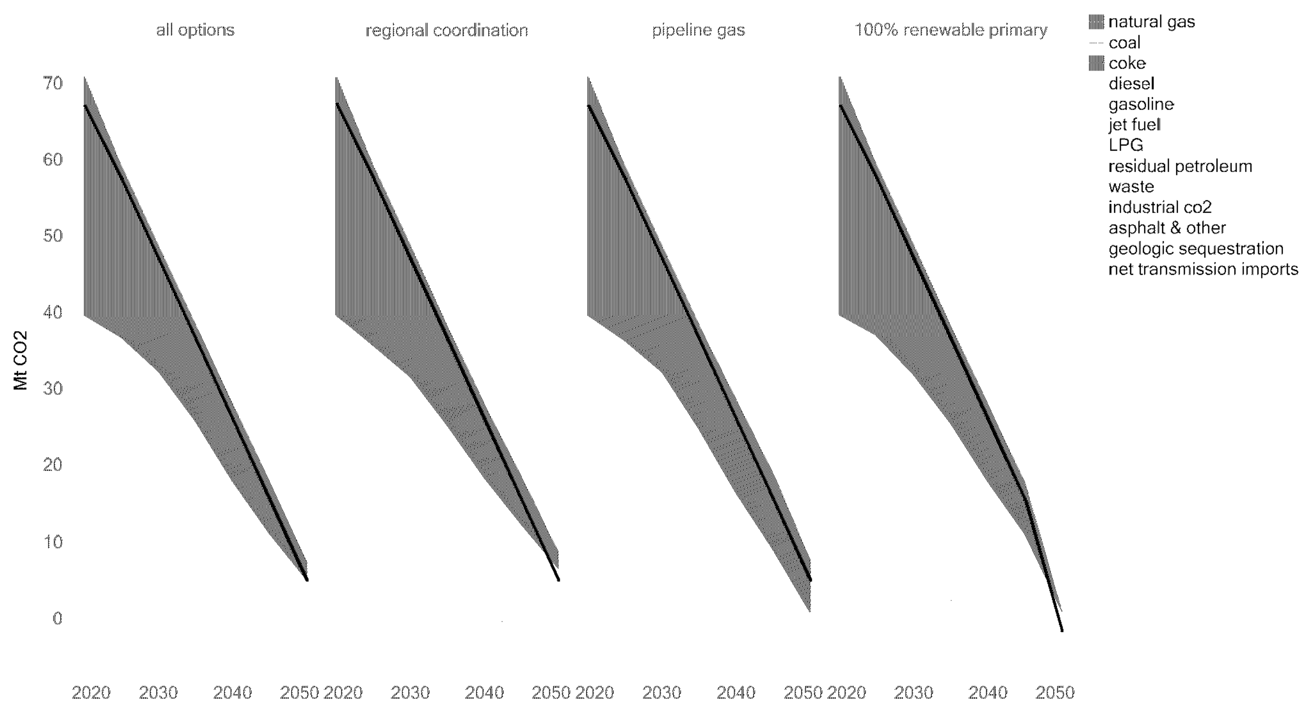
[31] These industrial emissions are assumed to be captured by 2050 and except in the Regional Coordination pathway, is combined with hydrogen in a Fischer Tropsch process to produce liquid fuels. When this fuel is burned, net positive emissions still occur, but this carbon for fuel production is lower cost than carbon from biomass within Massachusetts or from direct air capture.

asphalt (assumed to biomass-based asphalt, rather than petroleum-based in this scenario), the result is net negative emissions of 1.7 Mt CO_2.

Annual emissions from All Options and the three dissimilar pathways described above are shown in Figure 9 (results for all nine pathways including the reference case are shown annually in the supplemental materials, Figure 44). In each pathway, early declines in natural gas emissions due to electricity decarbonization, are followed by declines in petroleum fuels due to transportation electrification. Strategies of CO_2 exports and drop-in fuel replacements are not employed until after 2040. However, as noted in the discussion (Section 6.2.3), these fuels and carbon strategies must reach maturity through learning-by-doing before 2040 in order to be available at the scale required; this important dynamic is not captured in the modeling, but is an important piece to remember when crafting near term policies.

Electricity emissions reductions between 2020 and 2030 are critical for meeting a straight-line emissions trajectory between 2020 and 2050 because of stock-turnover inertia on the demand-side. The sales shares of electric and efficient end-use technologies are increased at a rapid pace (Section 5.3), but the stock composition changes slowly as a function of equipment lifetimes. Thus, the 2030 stock changes are not by themselves sufficient for Massachusetts to reach the 2030 economy-wide CO_2 benchmark. However, in electricity a combination of operational changes, renewables procurement, and increased imports, allows for a more rapid reduction in overall Massachusetts emissions. Because the emissions intensity of the ISO-NE grid is already below the national average, achieving the 2030 benchmark is particularly challenging due to the lack of the more easily implementable strategies found in many other regions (e.g. coal to gas switching).

Figure 9. Annual energy and industrial emissions from 2020-2050 for Massachusetts for four pathways. These pathways are highlighted because they show the greatest variability in the composition of emissions in 2050. The black line represents net emissions.



The supplemental results provide regional snapshots of emissions for ISO-NE states, both annual (Figure 42) and cumulative (Figure 43). Cumulative emissions across ISO-NE over the 2020-2050 period were 2.43 Gt in the All Options pathway versus 3.92 Gt in the reference case.

5.3 Demand-side transition

This section dives deeper into the final energy demand shown on the right side of the Sankey diagrams in Figure 7 to understand the changes in energy consumption. This section makes frequent use of the reference scenario to provide contrast for the decarbonization pathways. Without this, it can be difficult to tell which trends are a result of natural evolution in energy consumption, and which are strategies required for decarbonization. The reference scenario is based on the 2019 Annual Energy Outlook and both adoption of electrification and energy efficiency are assumed to be low. This scenario is not a forecast and does not represent current Massachusetts policy but is presented here only as a point of contrast.

Six of the eight decarbonization pathways share the same demand-side case—All Options, DER Breakthrough, Regional Coordination, No Thermal, Offshore Wind Constrained, and 100% Renewable Primary. To improve readability, only the All Options, Pipeline Gas, and Limited Efficiency pathways are shown in the figures that follow. Table 7 below maps each pathway to its demand-side case.

Table 7 Mapping from pathway to demand-side case. Multiple decarbonization pathways share the same demand-side case as All Options.

Pathway	Demand Case
Reference	Reference
All Options	All Options
DER Breakthrough	All Options
Pipeline Gas	Pipeline Gas
Limited Efficiency	Limited Efficiency
Regional Coordination	All Options
No thermal	All Options
Offshore Wind Constrained	All Options
100% Renewable Primary	All Options

5.3.1 **Final energy demand**

A summary of final energy demand in Massachusetts across the entire energy economy from 2020-2050 for the four demand-side cases is shown in Figure 10. As noted in Section 4 all pathways satisfy the same demand for energy services between 2020 and 2050. This means that, for example, the vehicle miles traveled, airline trips, and temperature set points in homes are identical between cases and that any changes in these values are the result of technology and not behavioral changes.[32] The service demand for 2020 is based on historical trends and do not include the impact of COVID-19. The impact of the pandemic will mean the 2020 numbers used in this analysis will differ in many ways from actual energy consumption that will be measured in the year; however, we do not expect this discrepancy to change any of the long-term findings from the analysis.

The All Options case implements both high electrification and high levels of same-fuel efficiency. The Limited Efficiency case implements the same electrification measures, but without the same-fuel efficiency

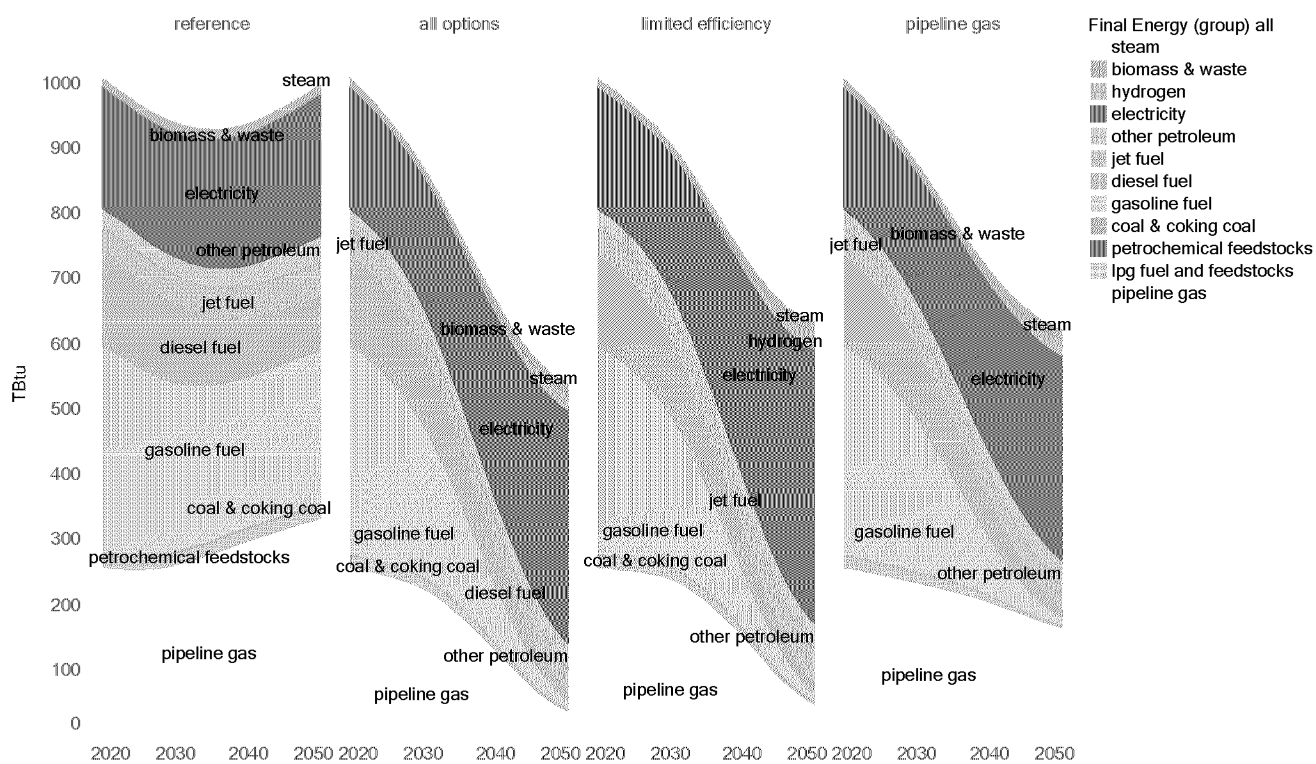
[32] As was noted elsewhere, consistent service demands across cases allows apples-to-apples comparisons, helping establish the robustness of decarbonization pathways. However, this is not to discount the potential role that energy conservation could have in mitigating the pace and scale of the energy system transition.

improvements. Finally, the pipeline gas case has the same transportation electrification and same-fuel efficiency as the All Options case, but lower rates of fuel switching away from pipeline gas.

All cases result in rapid declines in final energy demand, with the largest single factor being efficiency improvements from switching from internal combustion engines to electric drivetrains. Other reductions in final demand come from same-fuel efficiency—as highlighted by the contrast between All Options and Limited Efficiency—and the adoption of heat-pumps in buildings—as highlighted by the contrast between All Options and Pipeline Gas.

Figure 10 shows the final energy demand for the All Options, Limited Efficiency, and Pipeline Gas pathways alongside the reference case. Final energy demand for all the pathways sharing the All Options demand-side is reduced by nearly half below the reference case in 2050 (from about 1000 TBtu to about 550 TBtu). For both the Limited Efficiency and Pipeline Gas pathways, final energy demand is higher, roughly one-third below the reference case. For further insight into the differences between the cases, see the technical supplement (Figure 45), which highlights the difference in final energy demand between the reference case and the three decarbonized pathways.

Figure 10 Annual final energy demand for Massachusetts by fuel type.



Looking specifically at electricity consumption in Figure 11, it can be seen that load growth is attributable almost entirely to two sources: (1) vehicle charging; and (2) space and water heating in buildings. Other electricity demands decline in the near-term after an increase in efficiency and are roughly constant in the long-term (seen in the All Options & Pipeline Gas cases).

The differences resulting from the Limited Efficiency pathway are most stark in space and water heating where annual energy consumption increases 24% above the All Options case. As discussed in Section 5.3.5, this has significant implications for electricity system peak loads from heating.

Final energy consumption by sector is shown in Figure 12. The most dramatic changes from the reference case in all deep decarbonization pathways occur in transportation. Changes to building energy demand (residential and commercial) are less dramatic and differ across cases depending on the efficiency and electrification assumptions of each pathway. Industry shows the least change in final energy consumption in all pathways, because the opportunities for electrification are fewer and generally offer less efficiency benefit. Efficiency in industry, assumed to be 1% per year above the baseline, keeps industrial final energy demand flat. The next three sections will look closer at buildings, transport, and industry, respectively.

Figure 11 Annual electricity final demand in Massachusetts for transportation, heating, and other (all other loads). T&D losses are not included in final demand presented here but are accounted for in the supply-side electricity modeling.

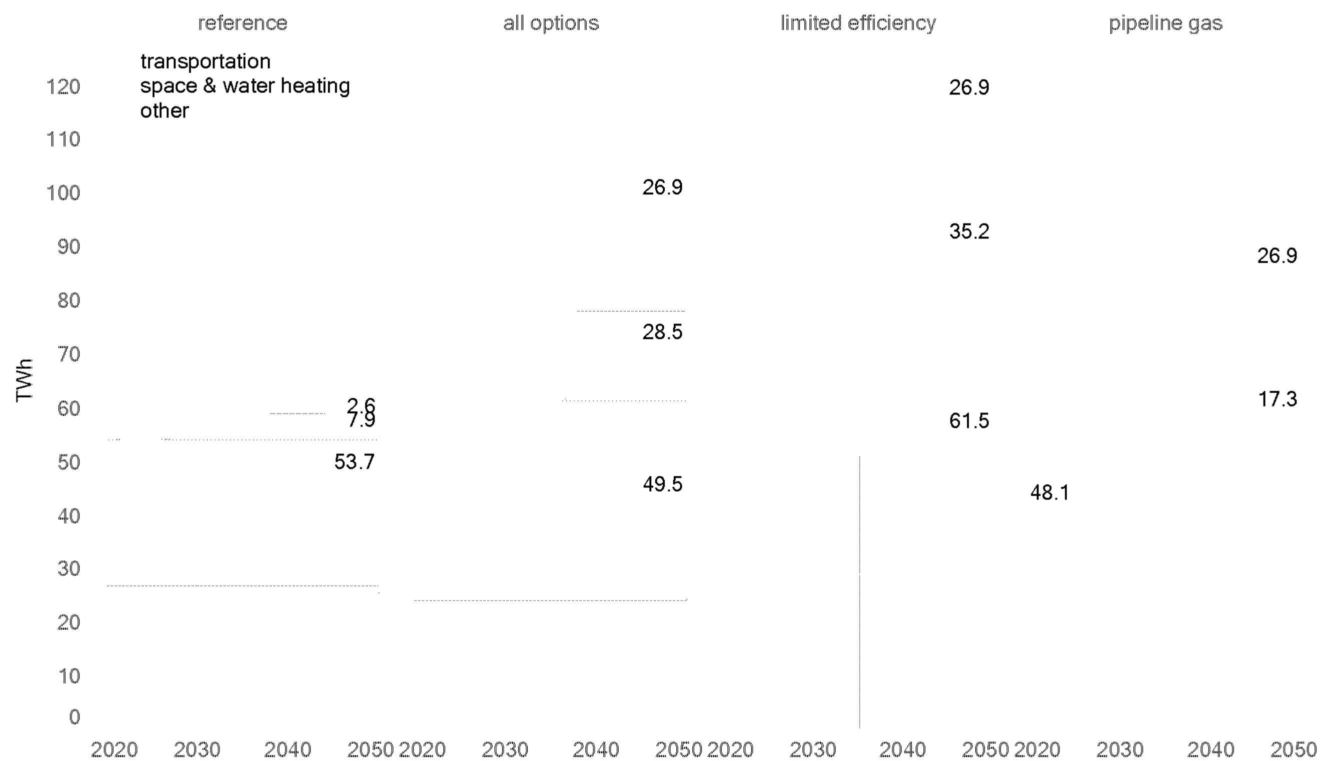
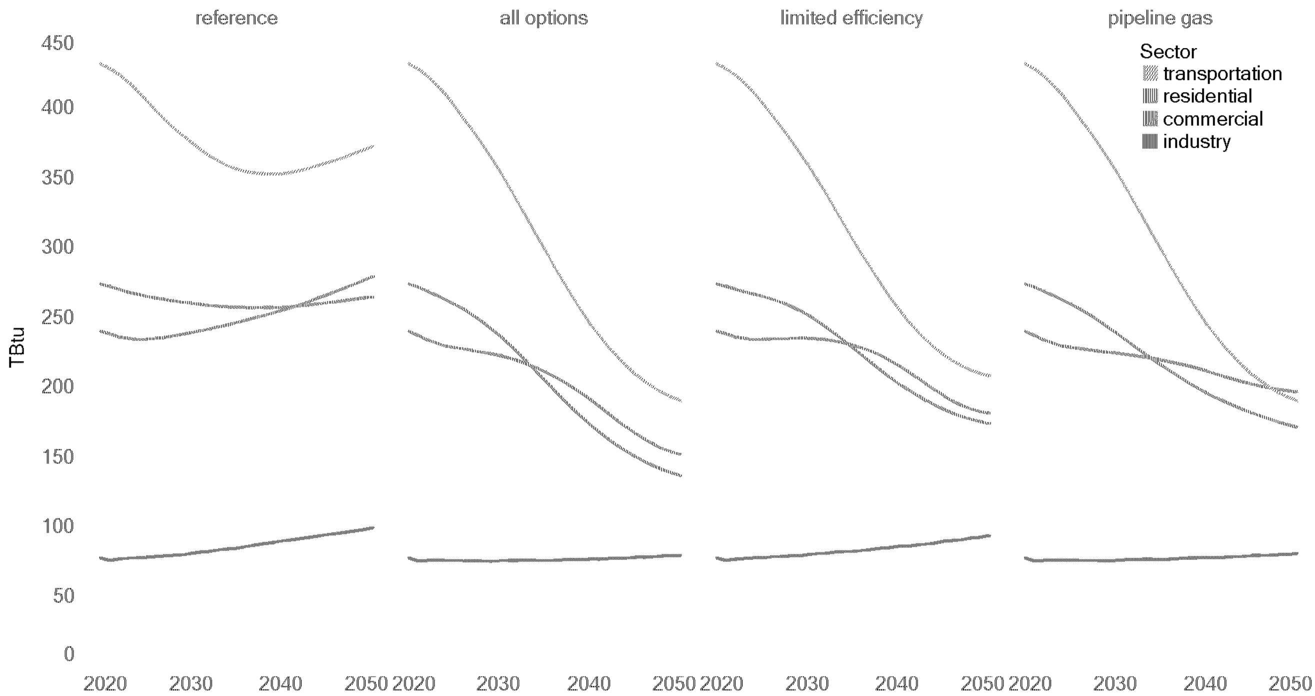


Figure 12 Massachusetts final energy demand by sector between 2020 and 2050. Differences in the levels of electrification-derived efficiency (All Options and Pipeline Gas) and same-fuel efficiency (All Options and Limited Efficiency pathway) lead to different patterns across pathways.



5.3.2 **Buildings**

Massachusetts final energy demand for all buildings by final energy type is shown in Figure 13. Distillate fuels, LPG, and pipeline gas together make up the majority of current building energy demand. Use of these fuels decreases significantly in all decarbonization pathways, accompanied by a rise in electricity demand. By 2050 in the All Options case, electricity comprises 80% of all energy consumed in the home (excludes vehicle charging).

Reductions in gas use, even to a modest extent in the Pipeline Gas pathway, come from the combination of improvements to building shells, appliance efficiency improvements that reduce hot water demand, and long-term climate-related trends in heating degree days. These factors reduce the service demand requirement for residential space heating by 30% between 2020 and 2050 (shown in supplemental materials Figure 47).

Figure 13 Massachusetts building (residential + commercial) final energy demand by fuel type. The impacts of electrification and energy efficiency can be seen in the contrast between 'reference', 'all options', and 'limited efficiency.' The pipeline gas pathway, as a result of assumptions, sees a modest decline in pipeline gas use, in part due to improved efficiency.

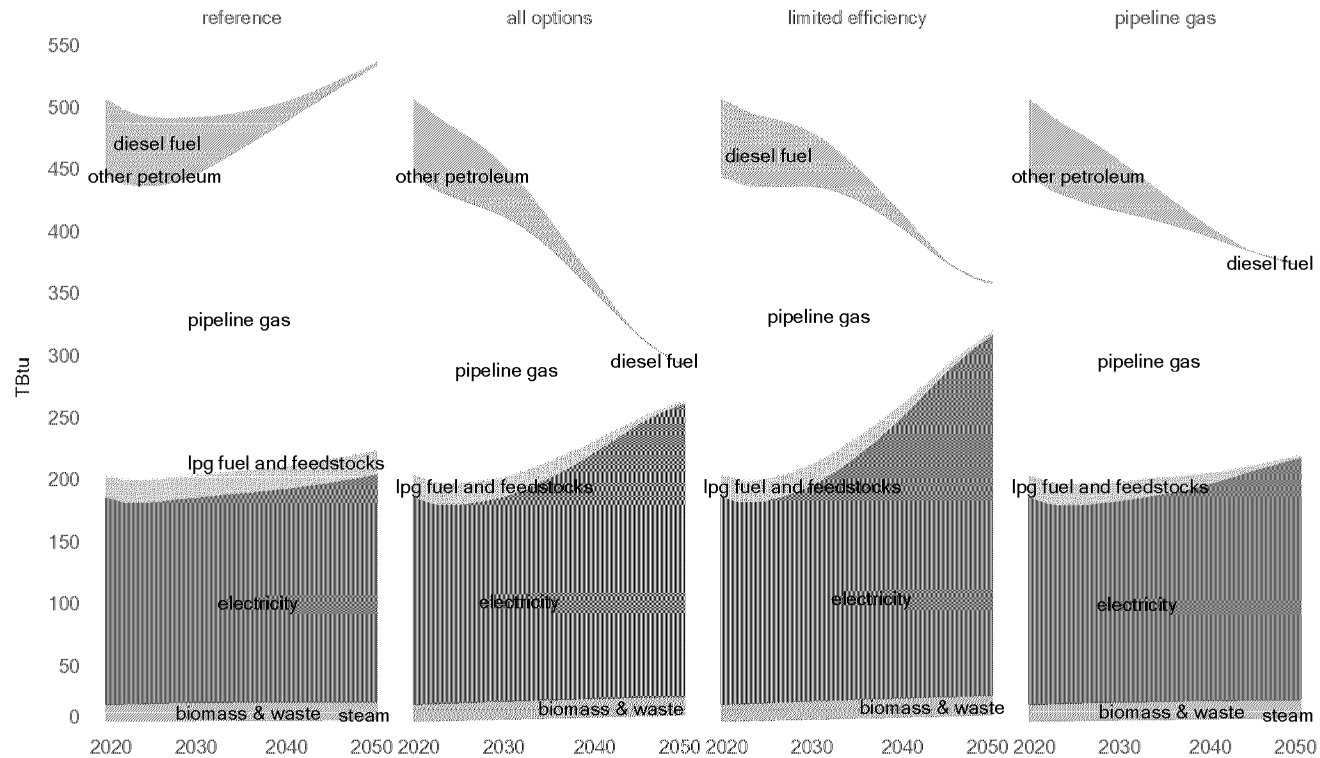


Figure 14 and Figure 15 break down the technology transitions for key subsectors in residential and commercial buildings, respectively. Distillate and LPG heating is assumed to switch to mini-split heat pumps across all cases, a trend that has already begun. The adoption of air source heat pumps and electric cooking occurs rapidly in the All Options and Limited Efficiency cases, in which heat pumps constitute 50% of new residential heating system sales in 2030. In residential buildings, virtually all heating system sales, except cordwood stoves, become electric soon after 2040. Commercial buildings undergo a similarly rapid transition in technology sales. Due to lower overall commercial heating demand[33] a larger share of electric resistance (rather than heat pump) adoption is assumed.

The pace of electrification and the ratio of air source heat pump to ground-source heat pump (as well as electric resistance) in different subsectors are both uncertain, but the implications of different trajectories downstream (for example, in electricity distribution) can be seen in the supply-side results. The emissions targets can be met under a wide range of adoption patterns, but each variation comes with its own tradeoffs and implications for costs and for effects on other sectors. For example, switching to an air-source heat pump provides space cooling benefits, with measurable public health benefits, likely directed to underserved communities, in the face of a warming climate. These issues are discussed at high degree of detail (e.g., for a variety of building typologies, locations, and uses) in the Buildings Technical Report.

[33] Lower surface area to volume ratios and larger incidental heating from lighting, plug loads, and building occupants. Large commercial buildings sometimes need to cool building interiors, even in winter.

Figure 14 Massachusetts residential building electrification. Subsectors with high electrification potential—space heating, water heating, and cooking—are shown for the All Options and Pipeline Gas pathways. Annual sales shares (based on input assumptions) are shown in the left-hand figures, the resulting technology stocks in the middle figures, and final energy demand in the right-hand figures.

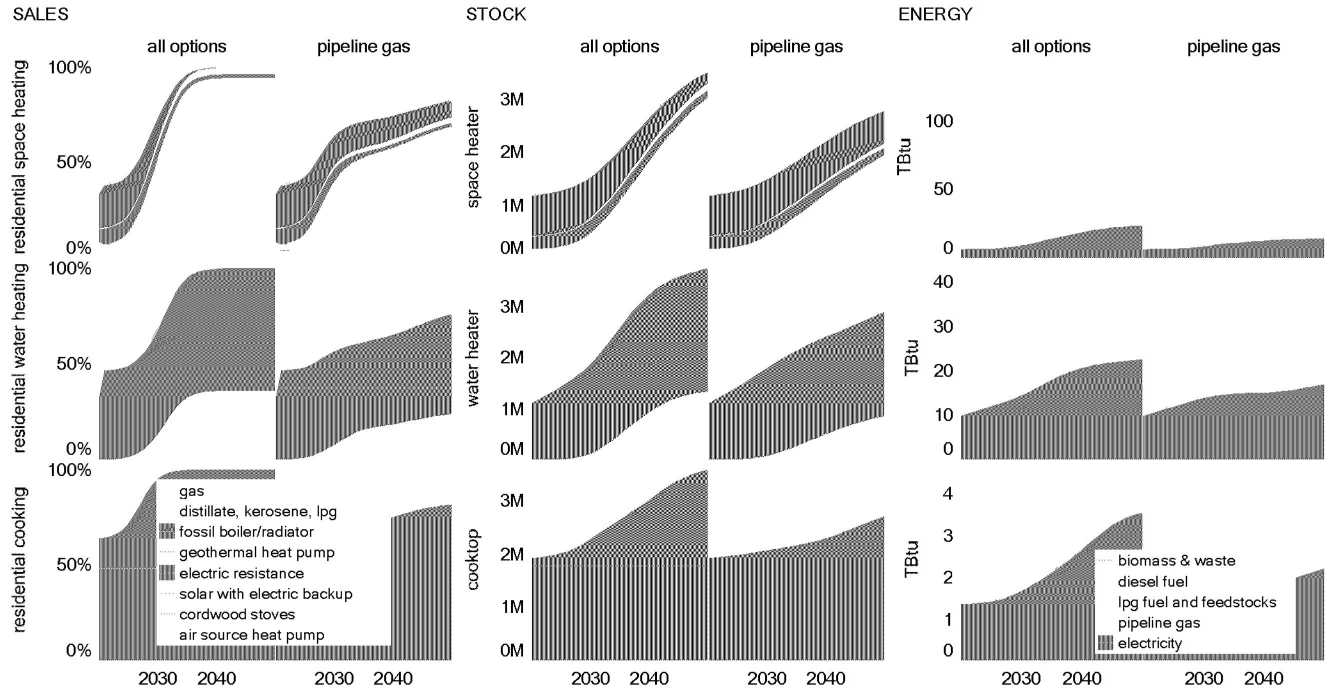
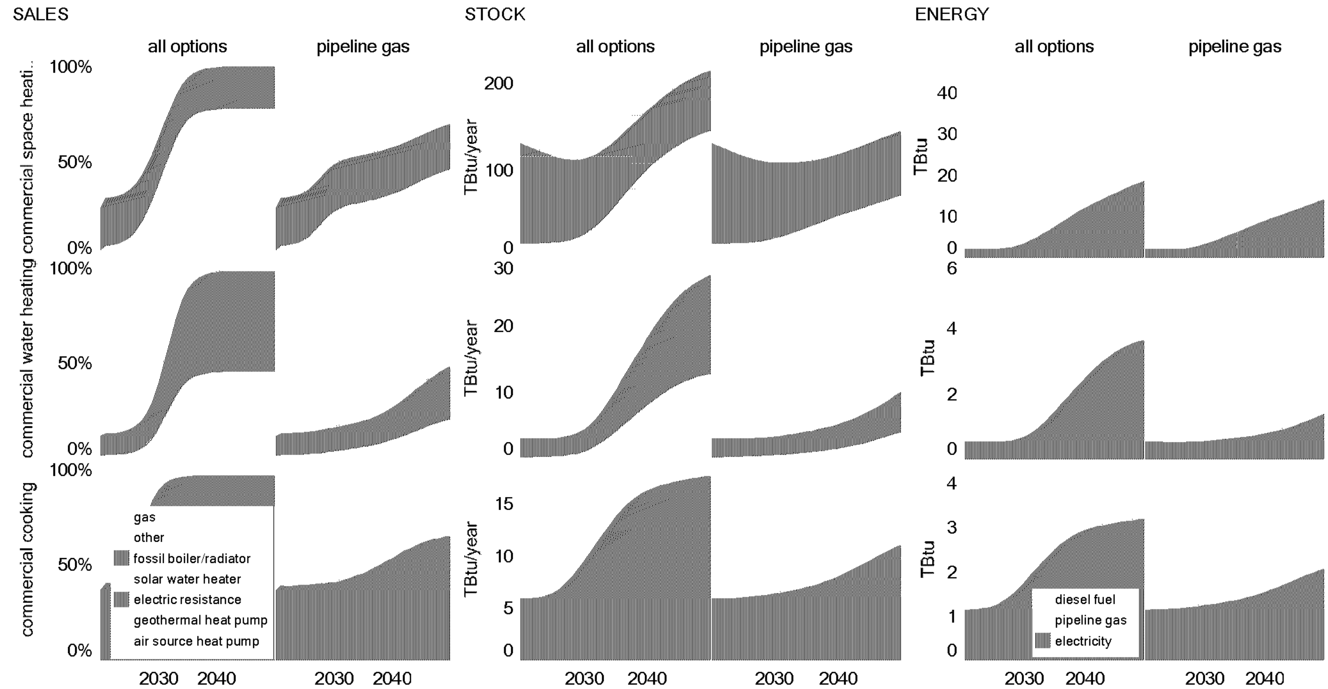


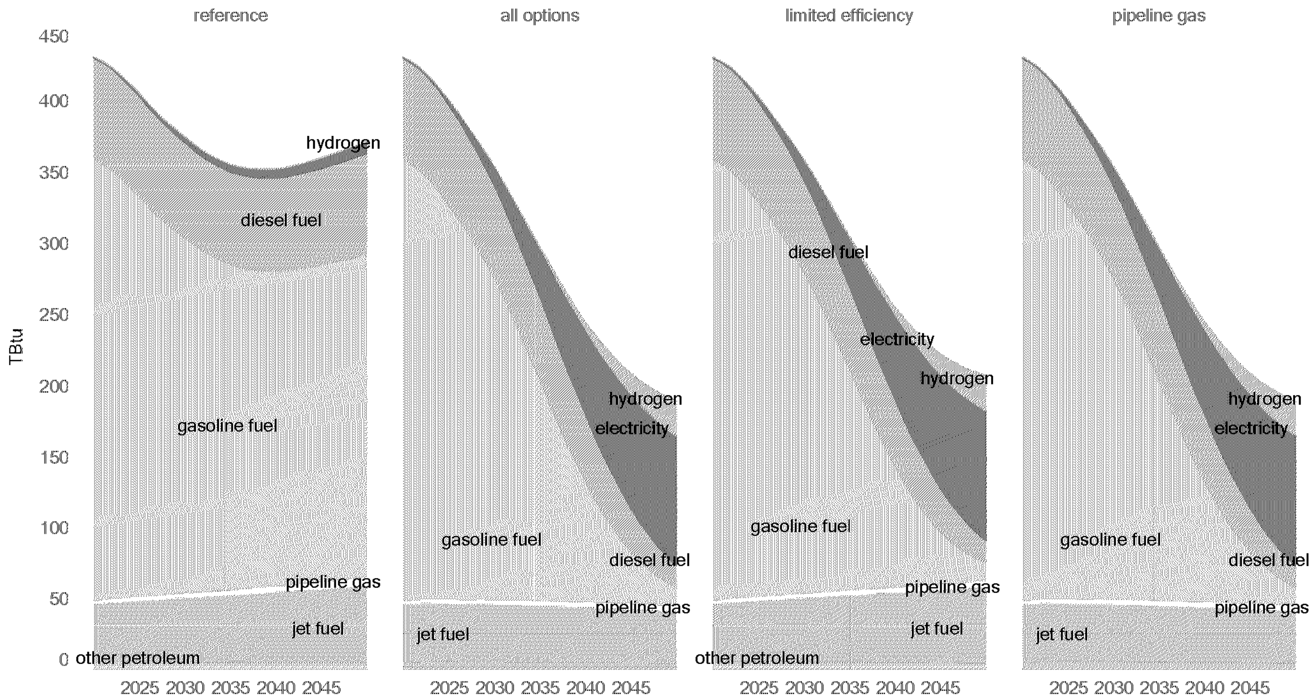
Figure 15 Massachusetts commercial building electrification. Subsectors with high electrification potential—space heating, water heating, and cooking—are shown for the All Options and Pipeline Gas pathways. Annual sales shares (based on input assumptions) are shown in the left-hand figures, the resulting technology stocks in the middle figures, and final energy demand in the right-hand figures.



5.3.3 **Transportation**

Transportation energy today comes primarily from three fuels: diesel, gasoline, and jet fuel, although compressed natural gas (CNG) and electricity both represent growing importance in certain duty-cycles. Figure 16 shows final energy demand by fuel type, 2020-2050. Diesel and gasoline use fall sharply in all deep decarbonization pathways, and electricity demand grows from minimal levels today to become the predominant source of final energy in 2050, with hydrogen playing a small but increasing role over time.

Figure 16 Massachusetts transportation final demand by fuel type compared between pathways. All compliant pathways share a common set of on-road vehicle assumptions; however, the Limited Efficiency case assumes no improvements in aviation energy efficiency.



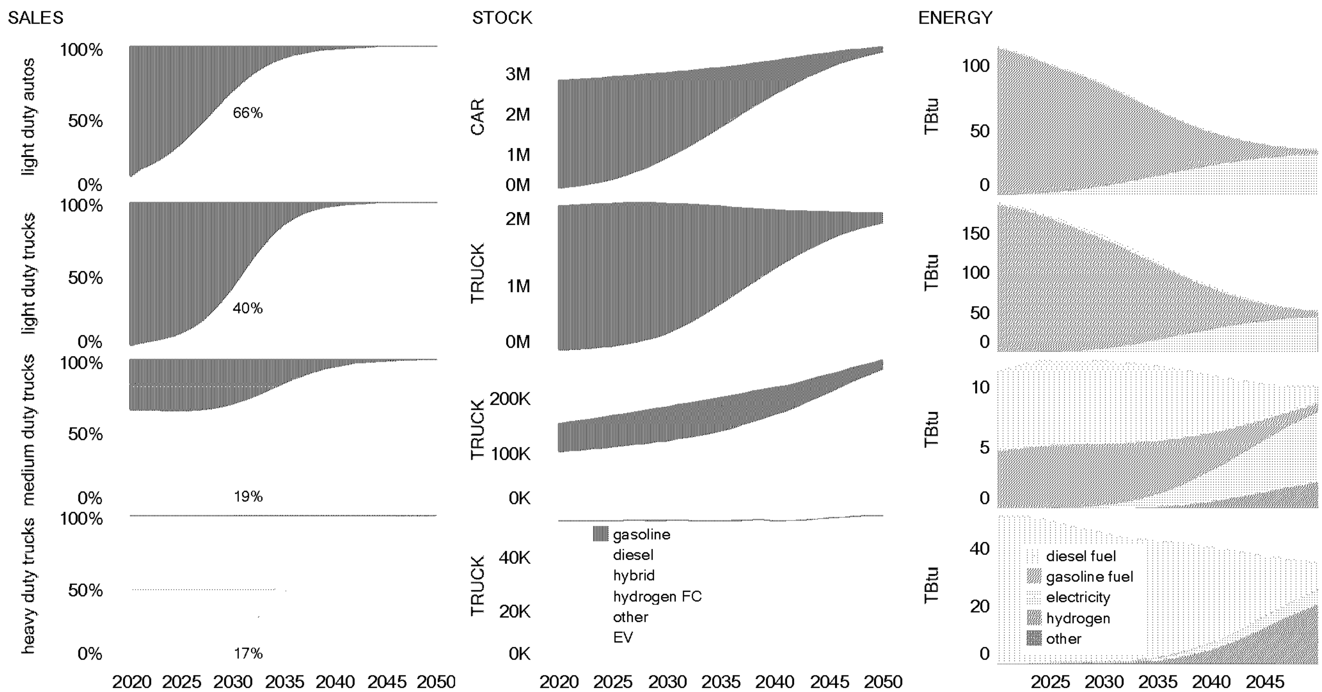
The sales, stock, and energy implications for this transformation of the main on-road subsectors (light duty vehicles, light duty trucks, medium duty trucks, and heavy duty trucks) is illustrated in Figure 17. As has been noted previously, electric drivetrains are approximately three times more efficient than internal combustion engines from a final energy perspective, which creates the dramatic decline in overall energy consumption. Light duty vehicles are assumed to become all battery electric vehicles. Medium and heavy-duty vehicles undergo a somewhat delayed transformation relative to light-duty, and with 2050 stocks split among battery electric, hydrogen fuel cell, and diesel vehicles. The split between hydrogen fuel cell and battery electric vehicles is less profound from a primary energy perspective[34] but has significant implications for delivery infrastructure (electric distribution systems and hydrogen fueling stations).

Aviation is the major off-road consumer of energy within the transportation sector. Consistent with MassDEP's GHG Emissions Inventory methodology, aviation emissions are determined from total fuel sales at commercial airports (rather than apportioning emissions according to emissions occurring within Massachusetts' airspace,

[34] Both can be supplied with zero carbon electricity, with battery electric vehicles holding a primary energy efficiency advantage.

or excluding international flights, for example). Our pathways assumed no fuel switching[35] and instead assumed continuous annual efficiency improvements of 1.5% per year. This results in a small decrease in jet fuel demand between 2020 and 2050, despite increasing passenger miles. Efficiency assumptions are discussed in Section 7.14. More detailed discussion of the timing and technological optionality for fleet- and duty-cycle transitions is included in the Transportation Technical Report.

Figure 17 Massachusetts on-road transportation subsectors breakdown by sales (based on input assumptions), the resulting stock, and final energy demand. All pathways share a common set of on-road vehicle assumptions. The percent of 2030 sales assumed to be electric is displayed on the first panel. Service demand (vehicle miles traveled) increases in all pathways, but final energy demand decreases due to the efficiency of electric drivetrains.



5.3.4 **Industry**

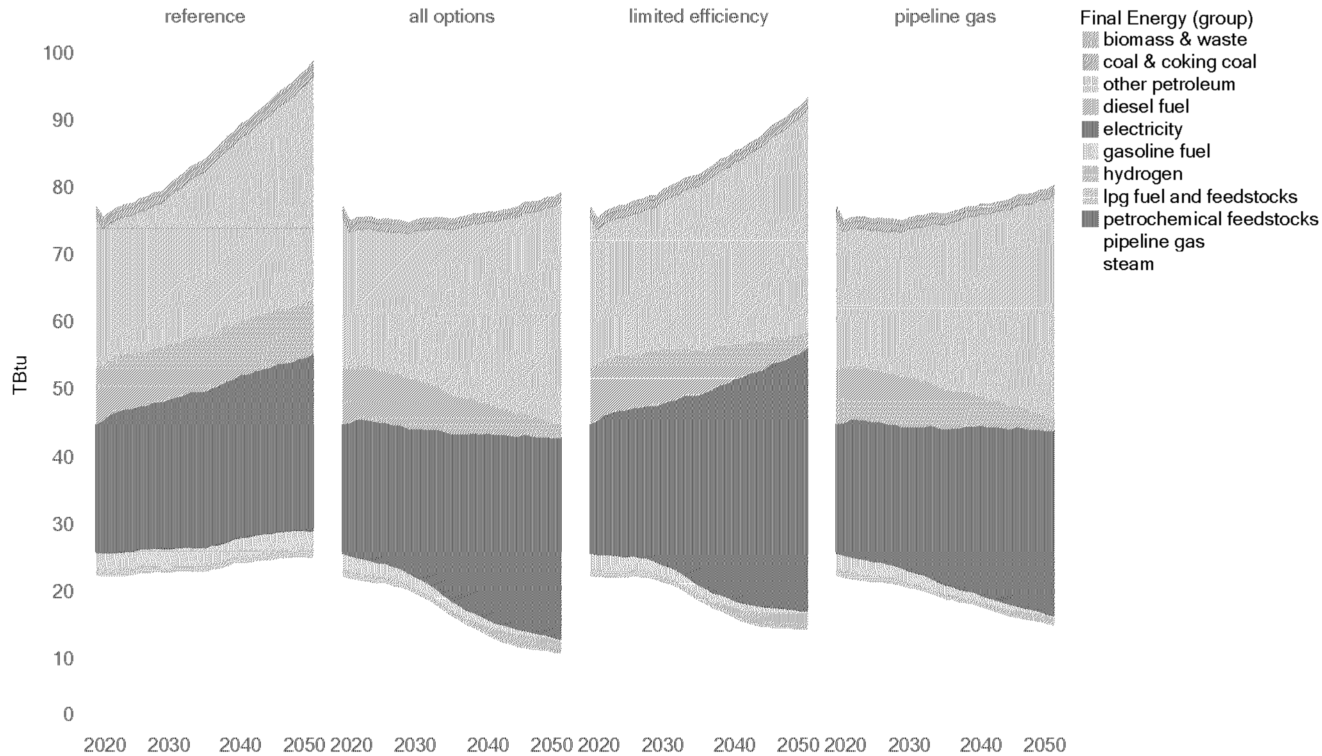
Figure 18 shows final energy demand in industry, separated by fuel type. The industrial sector within Massachusetts constitutes a smaller share of final energy demand than is the case in many parts of the U.S. The largest subsectors within industry are construction, including materials use, followed by various small manufacturing processes, paper products, and agriculture. Applications that require lower temperature process heat are directly electrified;[36] matching assumptions made in NREL's Electrification Futures Study.[37] In addition, hydrogen is used directly for a portion of the remaining energy demand in manufacturing, replacing pipeline gas. A share of construction and farm equipment that currently use diesel are electrified by 2050.

On top of the electrification measures listed above, an efficiency increase assumption of 1% per year across all of industry distinguishes the All Options from the Limited Efficiency pathway. Lime manufacturing is the most

[35] Many technologies, including hybridization and hydrogen, are being actively investigated in industry and many seem promising, particularly for short hops. However, these technologies were judged too nascent for inclusion in this analysis.
[36] Low temperature heat can be supplied with a heat pump or electric resistance element and is a more compelling electrification candidate than high temperature applications.
[37] National Renewable Energy Laboratory, Electrification Futures Study, https://www.nrel.gov/analysis/electrification-futures.html

significant source of non-combustion CO_2 emissions in the Commonwealth; it is the only such industrial process represented in this report.[38] It is assumed that carbon capture is deployed by 2045 to recover these emissions for use in the production of synthetic fuels or for export for geologic sequestration. The GHG emissions associated with the release of other non-CO_2 process emissions (such as fluorinated compounds used as refrigerants) are discussed in the *Non-Energy Sector Technical Report*.

Figure 18 Massachusetts final demand for fuels in industry. Electrification and efficiency improvements (1% per year in all cases except Limited Efficiency) result in the changes from the reference case. Most final fuel demand goes to combustion, resulting in positive gross emissions, but some does not, with the bulk of 'other petroleum' used as asphalt in construction. Use of bio-asphalts becomes a source of non-geologic sequestration.



5.3.5 **Electricity profiles**

Hourly electricity load profiles (also called load shapes) were built 'bottom-up' in EnergyPATHWAYS, as described in Section 3.1.1. Figure 19 and Figure 20 show hourly ISO-NE load shapes for the All Options and Pipeline Gas pathways. Each load shape is decomposed into three components of load: heating, transportation, and other. These represent gross load without the impact of behind-the-meter generation. The role of these components in annual electricity final demand is shown in Figure 11. Figure 48 in the technical supplement shows load shapes for the Limited Efficiency pathway, which highlights the role of efficiency in reducing heating peak load. In all of these figures, 'heating' includes water heating and some industrial processes in addition to space heating, accounting for the non-zero values of heating load during summer. In the winter, residential space heating grows over time to become an increasingly large component of peak load.

[38] Process emissions are the result of chemical processes and are unavoidable, but the resulting CO_2 can be captured.

Comparing the All Options and Pipeline Gas pathways, the main difference is in peak load for heating (31.5 GW versus 21.9 GW). The All Options pathway becomes a winter peaking system due to higher heating demand growth, while the Pipeline Gas pathway becomes a dual peaking system with both summer and winter peaks.[39]

Figure 19 ISO-NE electricity load decomposed into heating, transport, and other for the All Options pathway.

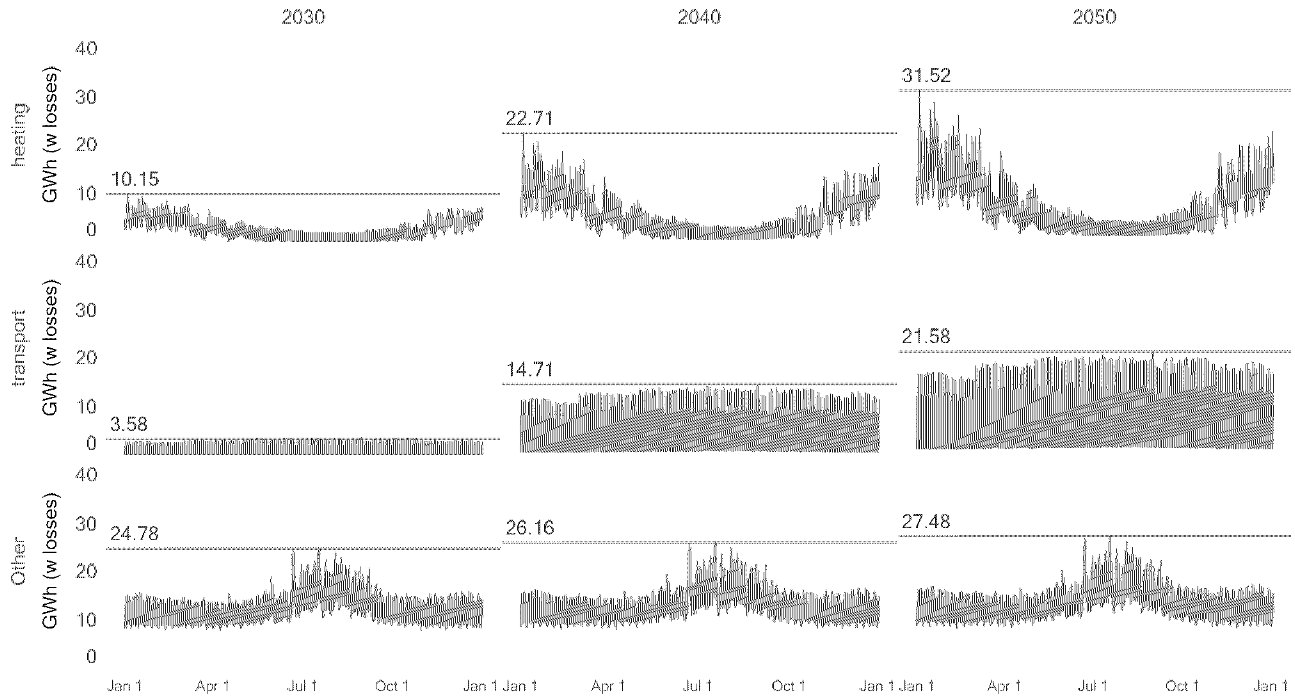
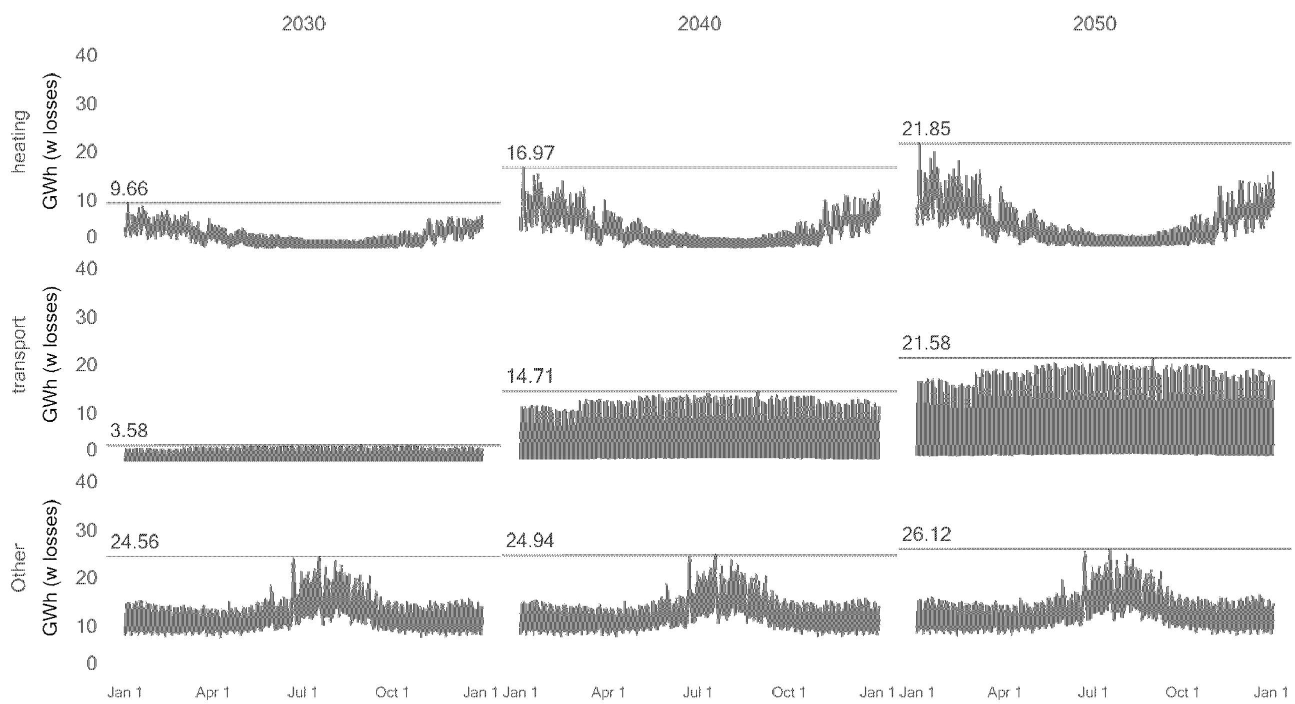


Figure 20 ISO-NE electricity load decomposed into heating, transport, and other for the Pipeline Gas pathway.



[39] For weather year 2012, which was the focus of this study, the Pipeline Gas pathway peak occurs in the summer.

Each load component has different flexibility characteristics, as described in Section 7.10. Vehicle charging provides the bulk of flexible load capability, with 50% of the unmanaged charging shape capable of being delayed by up to 8 hours. Space and water heating were also treated as flexible, but to a lesser degree.[40] Focusing only on Massachusetts, and accounting for flexible loads, Figure 21 shows the resulting load shapes in 2050 for the All Options and Pipeline Gas pathways. Winter peak heating loads in 2050, which typically occur during morning hours, are anti-coincident with today's system peak loads, which occur in late afternoon during summer. On the other hand, transportation charging load is highly correlated with existing summer loads, occurring as people arrive home from work and plug in their vehicles. As a result, summer peak on residential feeders grows somewhat in tandem with winter heating load, resulting in a smaller relative difference between the two pathways than might be assumed. This demonstrates the importance of what assumptions are made regarding the extent of transportation electrification and flexible charging behavior when evaluating what peak load will be with and without high heating electrification. This is discussed further in Section 6.2.1.

Figure 21 Massachusetts load in the All Options and Pipeline Gas pathways with end-use flexibility, separated by residential customers and commercial & industrial (C&I) customers. Growth in summer peak load from vehicle charging that is coincident with air conditioning loads reduces the relative differences between the two pathways.

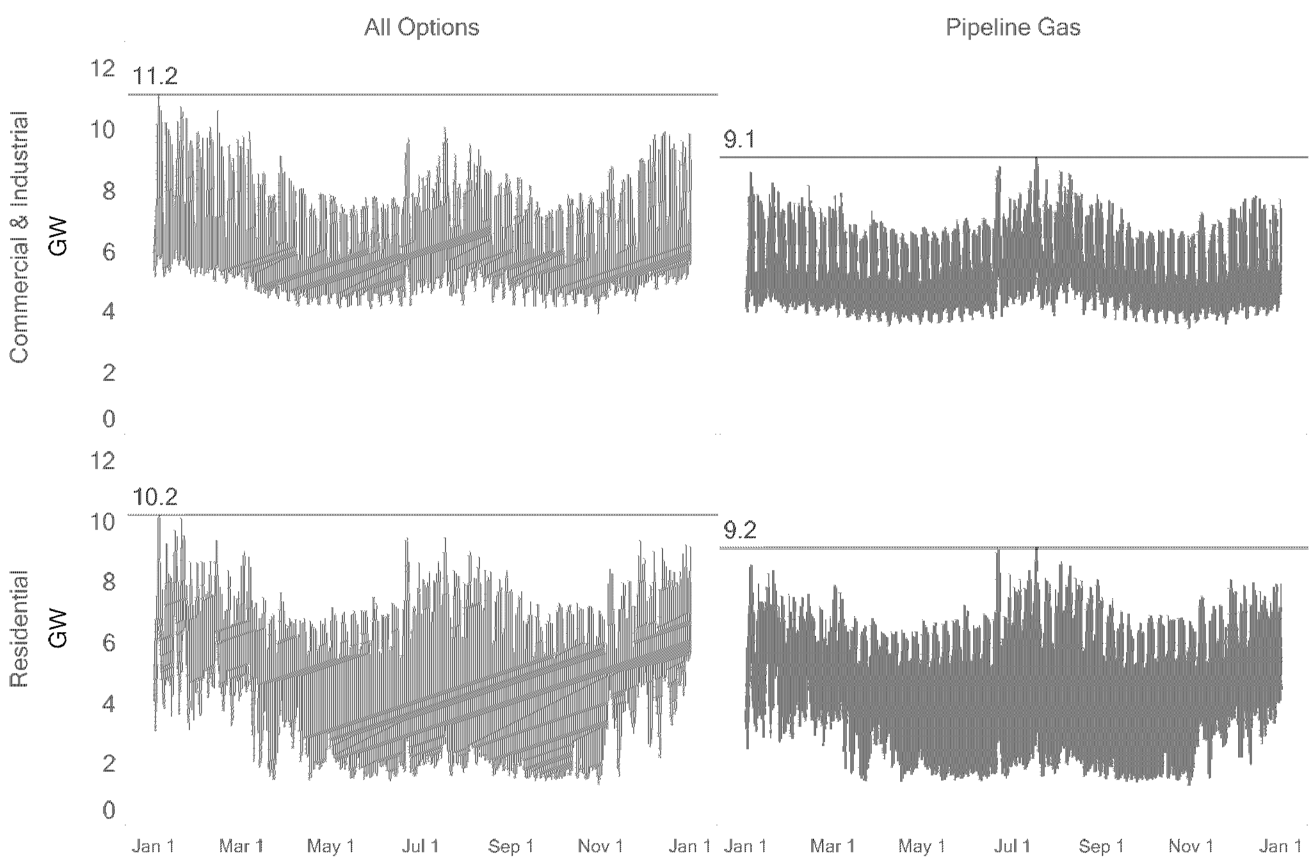


Figure 52 in the technical supplement makes an additional comparison of ISO-NE load in 2050 to Quebec's load today. This comparison provides a helpful empirical perspective on the likely trajectory of electricity load under deep decarbonization, because heating in Quebec is already highly electrified today. It also suggests that

[40] 15% of space heating and cooling load is assumed to be flexible with the ability to shift a single hour. 25% of water heating load is assumed flexible with up to a 2-hour shift.

peak loads between ISO-NE and Quebec are likely to become more coincident over time, challenging the electricity system in new ways. This is examined in the next section.

5.4 Electricity

5.4.1 Low carbon electricity systems

Electricity systems are the hub around which deeply decarbonized energy systems are organized, and in general they supply the lowest-cost zero-carbon primary energy for the economy. There are four broad technological approaches to generating decarbonized electricity, and within each there are several different technology types:

1. Renewable generation: wind, solar, hydro, and solid biomass.[41]
2. Decarbonized drop-in fuels used in thermal generation: biogas, hydrogen, and synthetic fuels (power-to-gas).
3. Fossil generation with carbon capture and storage (CCS): post-combustion CCS with 90% CO_2 capture, and pre-combustion or Allam cycle CCS with ~100% CO_2 capture.
4. Nuclear generation: existing Gen II reactors and new Gen III and Gen IV reactors, including small modular reactors (SMRs).

Renewables, drop-in fuels, and fossil fuels with carbon capture (CC) were options evaluated in all pathways, but only the Regional Coordination pathway permitted the export of carbon for sequestration out-of-state. Nuclear power was evaluated in the Offshore Wind Constrained pathway, but at costs that were not reflective of a potential breakthrough in SMR design. The costs and performance characteristics of all generating technologies are described in Section 7.8.

The RIO model was used to determine the mix of electricity technologies in future years that minimized cost while maintaining reliability and meeting carbon targets; the methodology is described in Section 3.1.2. Based on current cost and performance forecasts, the lowest cost electricity systems for the Northeast were found to be organized around renewable generation, primarily wind, solar, and hydro, plus decarbonized drop-in fuels burned in existing thermal power plants.[42] Existing nuclear capacity was maintained to the extent possible, and new nuclear capacity was built in situations in which renewable potential was severely constrained, though not necessarily in Massachusetts. Due to a lack of geologic sequestration potential in the northeast region, carbon capture on power plants was not economic in any pathway. Since wind and solar generation, the least-cost forms of electricity supply, are also both variable and intermittent, electricity systems had to be fundamentally reorganized to address the energy imbalances between renewable output profiles and load. The required changes constitute a dramatic shift in electricity planning and operations, as explored in detail in the rest of this section.

5.4.2 Energy and capacity

5.4.2.1 Massachusetts

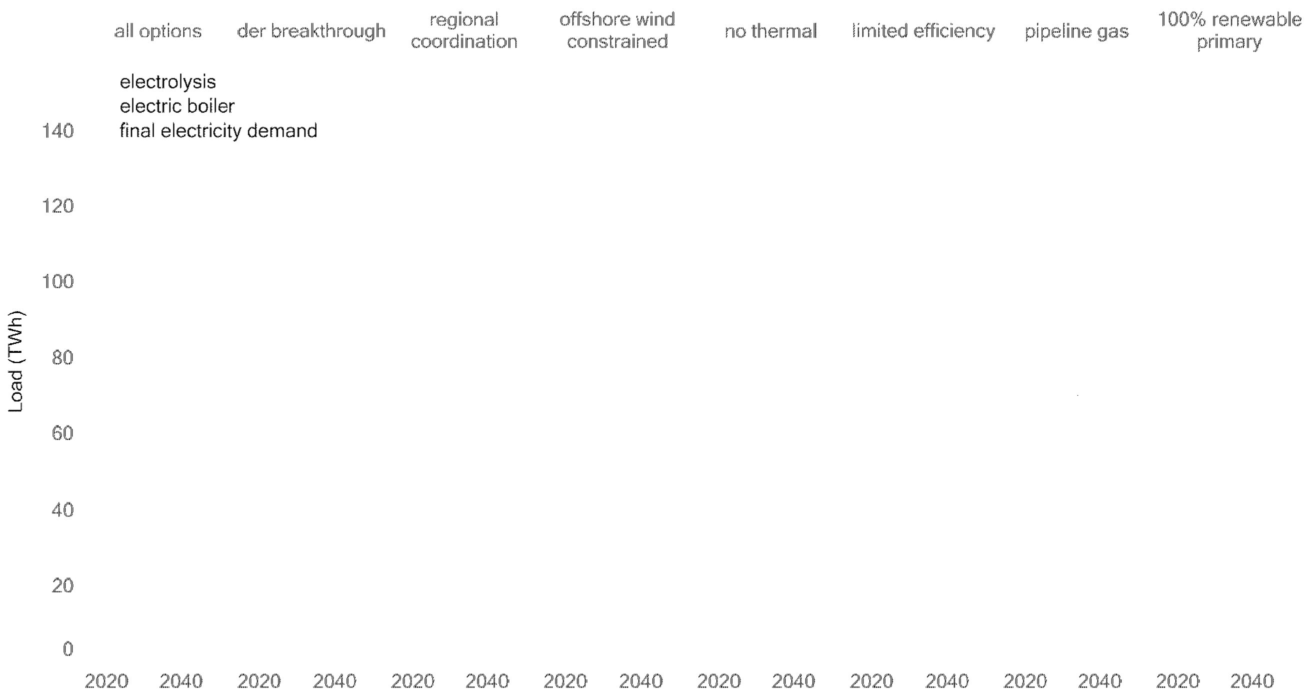
Decarbonized power systems serve two different types of electricity demand. The first type is final electricity demand, in which electricity itself is the form of energy required by end-use loads, which must be served at all

[41] Tidal, wave, and geothermal generation were not included in this work, either because they are not competitive based on current cost projections, or because their technical potential confines them to niche contributions in the Northeast. Further breakthroughs in these technologies are to be encouraged, but would not be expected to fundamentally alter the electricity sector solutions presented here.

[42] Based on the equipment lifetimes assumed in this study, most existing power plants required re-powering before 2050.

times. As described in Section 5.3.1 and shown in Figure 11, electrification results in major growth of final electricity demand, despite aggressive efficiency measures. The second type is intermediate electricity demand, in which electricity is used in flexible energy conversion processes to produce other forms of final energy such as hydrogen and steam. This second use of electricity is almost entirely new and brought about in order to reach the decarbonization goals. The optimal level of intermediate demand was determined endogenously in the RIO model, such that the overall carbon target was met at lowest cost. Both types of load are shown in Figure 22. In all pathways, hydrogen and steam production loads became significant after 2040. Their production and use are shown schematically in the Sankey diagrams in Figure 7.

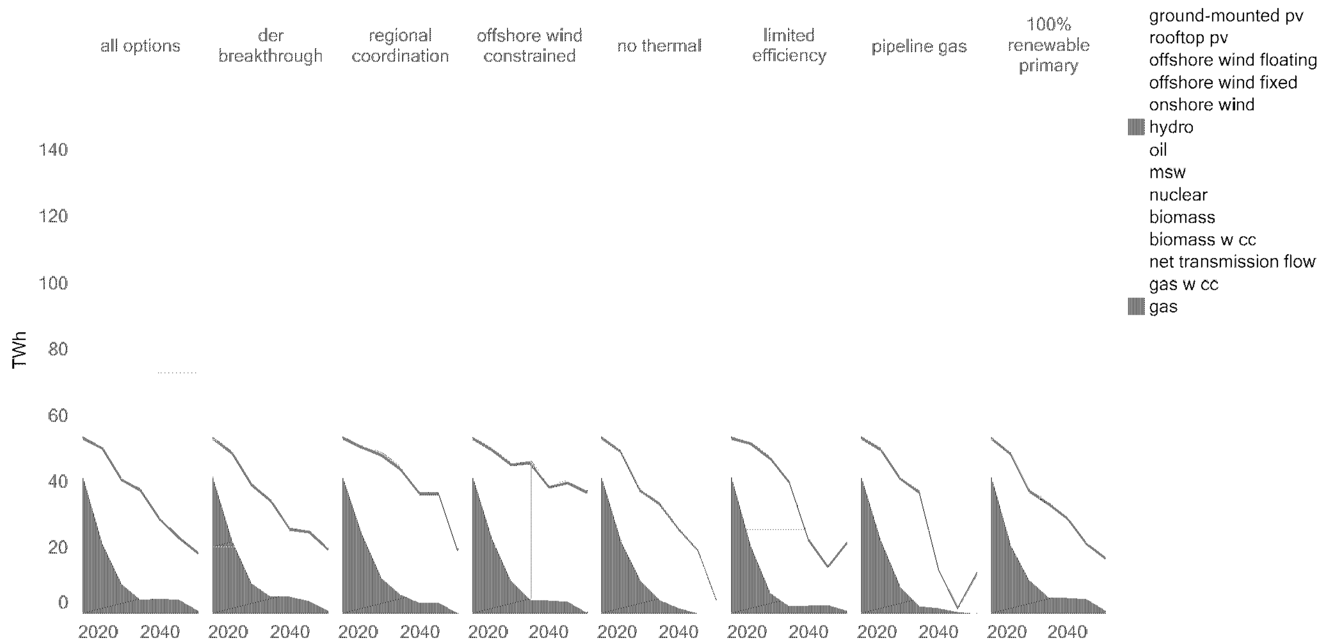
Figure 22. Massachusetts electricity consumption for end-use final electricity demand and energy conversion loads (electrolysis and electric boilers). Figure includes T&D losses. Final electricity demand was determined in EnergyPATHWAYS. Conversion loads were optimized in the RIO model to reach the emissions target at least cost.



Massachusetts electricity demand (Figure 22) was met using the supply resources shown in Figure 23. The change in generation mix as the system was decarbonized follows the same basic pattern across all scenarios: a rapid decrease in thermal generation, accompanied by a rise in electricity imports, followed by a continuous and dramatic expansion of renewable generation, especially offshore wind. Within this broader pattern, each pathway shows some variation, which are described below in comparison to the All Options pathway.

The DER Breakthrough pathway effectively traded ground-mounted PV for rooftop PV but ended up with a similar level of solar generation and overall resource profile. The Regional Coordination pathway used more imported electricity in the medium-term and delayed some offshore wind development. The Offshore Wind Constrained pathway increased imports to compensate for lower offshore wind build. The No Thermal pathway built significantly more solar PV than other pathways and had the lowest net electricity imports in 2050. The Limited Efficiency pathway had an even faster reduction in gas generation and more renewable generation in absolute terms. The Pipeline Gas pathway had a very steep reduction in thermal generation, similar renewable generation, and less imported electricity. The 100% Renewable Primary pathway is similar to the All Options pathway, with slightly less overall generation because a larger share of fuels were imported than made within Massachusetts. All pathways except for No Thermal used some pipeline gas in power generation, but gas' share of annual electricity production declined by 90% or more across all pathways.

Figure 23. Massachusetts annual electricity supply by resource type for all pathways.

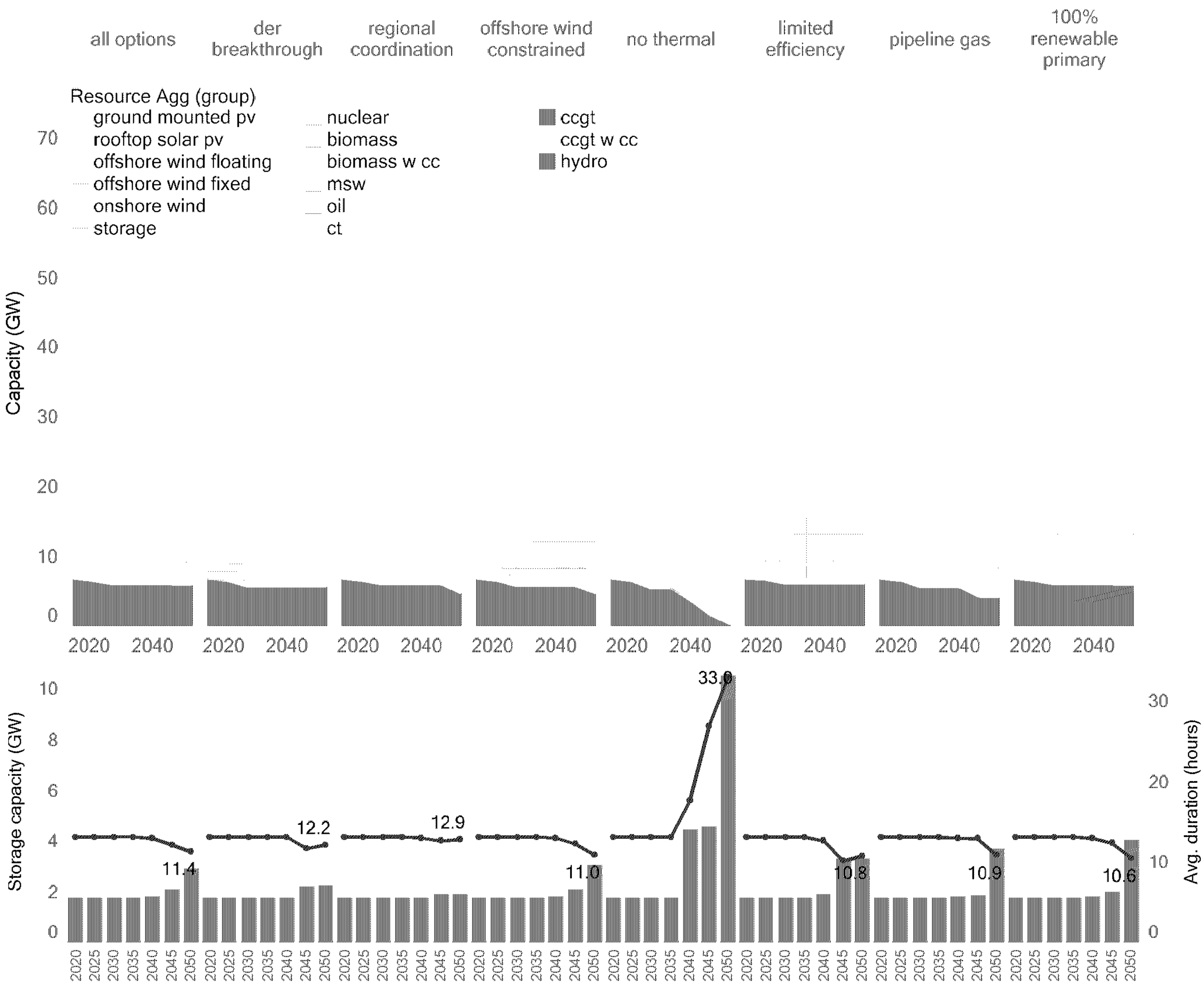


Massachusetts generating capacity shown in Figure 24. The main features of its changing composition as the system is decarbonized is best understood by focusing in turn on three key elements: thermal capacity, renewable capacity, and storage capacity.

Thermal capacity: A large proportion of existing combined cycle gas turbine (CCGT) capacity remained online in all pathways except No Thermal, in which it was explicitly retired. Pathways that had either high transmission build to Quebec (Regional Coordination and Offshore Wind Constrained) or lower final electricity demand (Pipeline Gas) retired a small amount of the current gas capacity by 2050, but other pathways maintained the capacity at current levels. Oil-fired peaking power plants were retired by 2030 in all pathways. The public health impacts of maintaining gas generation (at a 90% reduction in annual runtime) were not included the cost computations that led to that maintaining this capacity as the least-cost solution (compared to, for example, large-scale battery storage); however it is unlikely that explicitly including those costs would alter the outcome of the model's cost optimization. Distributional impacts of these health costs are discussed with an environmental justice and equity perspective in the Roadmap Study Report. In some cases, hydrogen and zero-carbon gas alternatives were blended into the combustion mix to reduce the GHG footprint of remaining thermal capacity.

Municipal Waste Combustors (MWCs) are not dispatched as electricity generating units in the model to meet peak demands or compensate for valleys in renewable generation due to their characteristics. Therefore, municipal waste combustors are not assumed to produce electricity in 2050 in this analysis. However, some MWCs may still operate in 2050 for the purposes of waste disposal; this is discussed in the *Non-Energy Sector Technical Report*.

Figure 24. (Top) Massachusetts electricity capacity by year and pathway. (Bottom) Average duration (hours) for energy storage in each year.



Renewable capacity: All pathways built 6.7 GW of fixed offshore wind capacity by 2050. Floating offshore wind capacity ranged from 4.2 GW in the Offshore Wind Constrained pathway to 12.7 GW in the Limited Efficiency pathway. Floating offshore wind was built primarily after 2035. Onshore wind did not expand significantly in any pathway, with an installed capacity range of 450-750 MW in 2050. Solar capacity in 2050 was greater than wind capacity in all pathways when ground-mounted and rooftop PV are added together. However, wind produces more energy than solar due to its higher capacity factors (the amount of energy produced per unit of capacity installed). The Regional Coordination pathway has the least solar PV capacity within Massachusetts because the solar is built in states with more available land and connected to Massachusetts via transmission. The No Thermal pathway has almost twice the installed solar PV capacity of any pathway.

Storage capacity: Massachusetts has 1.8 GW of pumped hydro storage that is maintained in all pathways. These resources are supplemented with new battery storage capacity built for bulk energy shifting after 2035. As noted in the caveats in Section 3.3, this new storage capacity does not include storage built as a wires alternative within Massachusetts, or distributed storage that is deployed behind the customer meter. That type of small-scale storage may represent a key component of the flexible load required to balance grid operations and mitigate peak impacts in 2050, but is not likely to accommodate the high capacity, long-duration discharges need of the type of storage discussed here. Distributed storage and microgrid operation (including the possibility of vehicle-to-grid reverse EV charging) is discussed in greater detail in Section 5.4.3 of this report. The No Thermal pathway required 10.5 GW of total energy storage, with an average duration of 33 hours, to eliminate the needed thermal capacity. As explained in section 6.1.2, this capacity is a lower bound on the estimate for long duration storage needed to maintain reliability if thermal capacity is precluded.

5.4.2.2 Northeast Region

In this study, Massachusetts is one state within a decarbonizing regional electricity system in which planning and operations were assumed to work in concert in order to achieve very low GHG emissions at low cost. Figure 25 shows annual electricity supply in the All Options pathway for each of nine study zones (the rest-of-US zone is omitted). Massachusetts offshore wind development was mirrored in Maine and Rhode Island, both of which exported wind to surrounding states. Connecticut, New Hampshire, and Vermont were modeled to have more limited (or no) offshore wind potential,[43] and so a higher fraction of their renewable generation was from solar. In both Connecticut and New Hampshire nuclear capacity was maintained, by assumption, through 2050, except in the 100% Renewable pathway. New York developed significant offshore wind and solar capacity, and also appreciable onshore wind capacity. By 2050, New York became the largest importer of electricity from Quebec. The Quebec hydro build anticipated in response to the 83(d) procurement did come online by 2030, but there was no new hydro after 2030 except in the No Thermal pathway. Instead, Quebec built onshore wind to supply its new transportation electrification loads domestically, and also for export. Finally, New Brunswick retired coal in the near term to reduce emissions, followed by a large build of onshore wind to complement its small hydro and nuclear capacity. Its transmission ties to Quebec were important for balancing, but net-imports were not a major factor for meeting load.

[43] New Hampshire has limited coastline, Vermont has no offshore wind opportunity, and offshore wind resource quality in Connecticut is lower than in surrounding states based on NREL wind simulations. The assignment of wind resources to states is discussed further in Section 0.

Figure 25. All Options pathway annual electricity supply by zone for seven northeastern U.S. states, New Brunswick, and Quebec. Positive values for net transmission flow represent net imports, and negative values represent net exports.

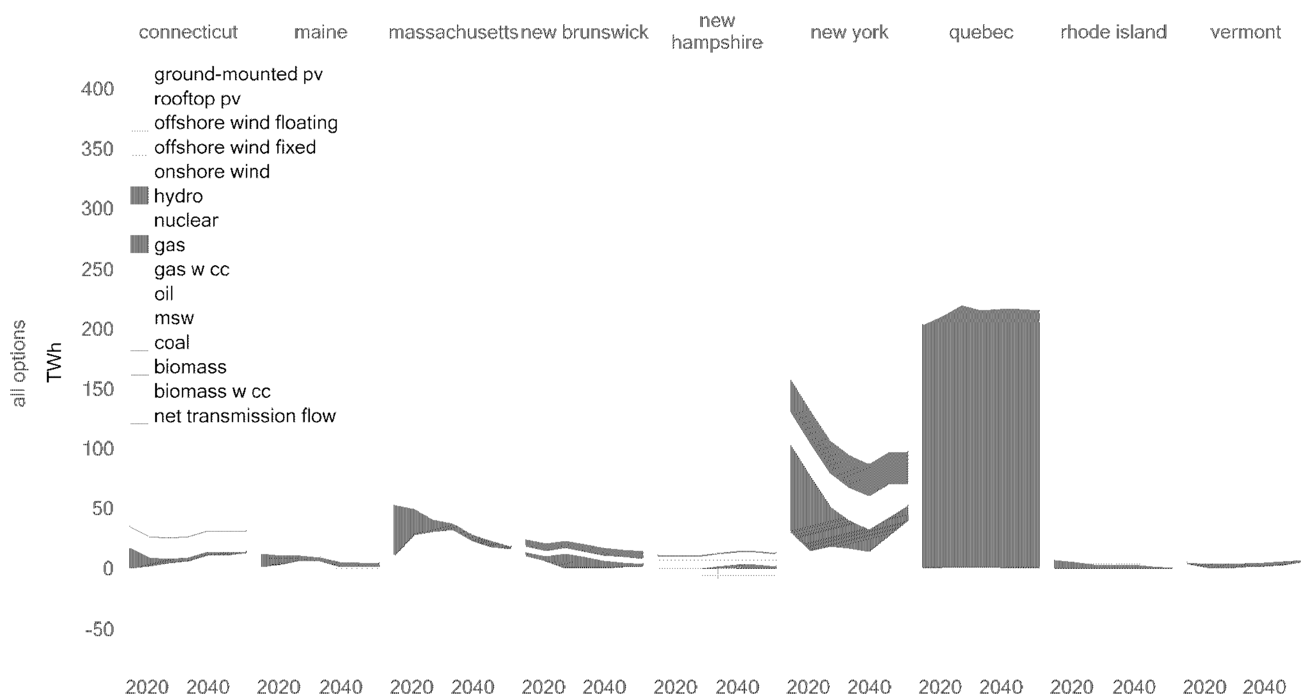
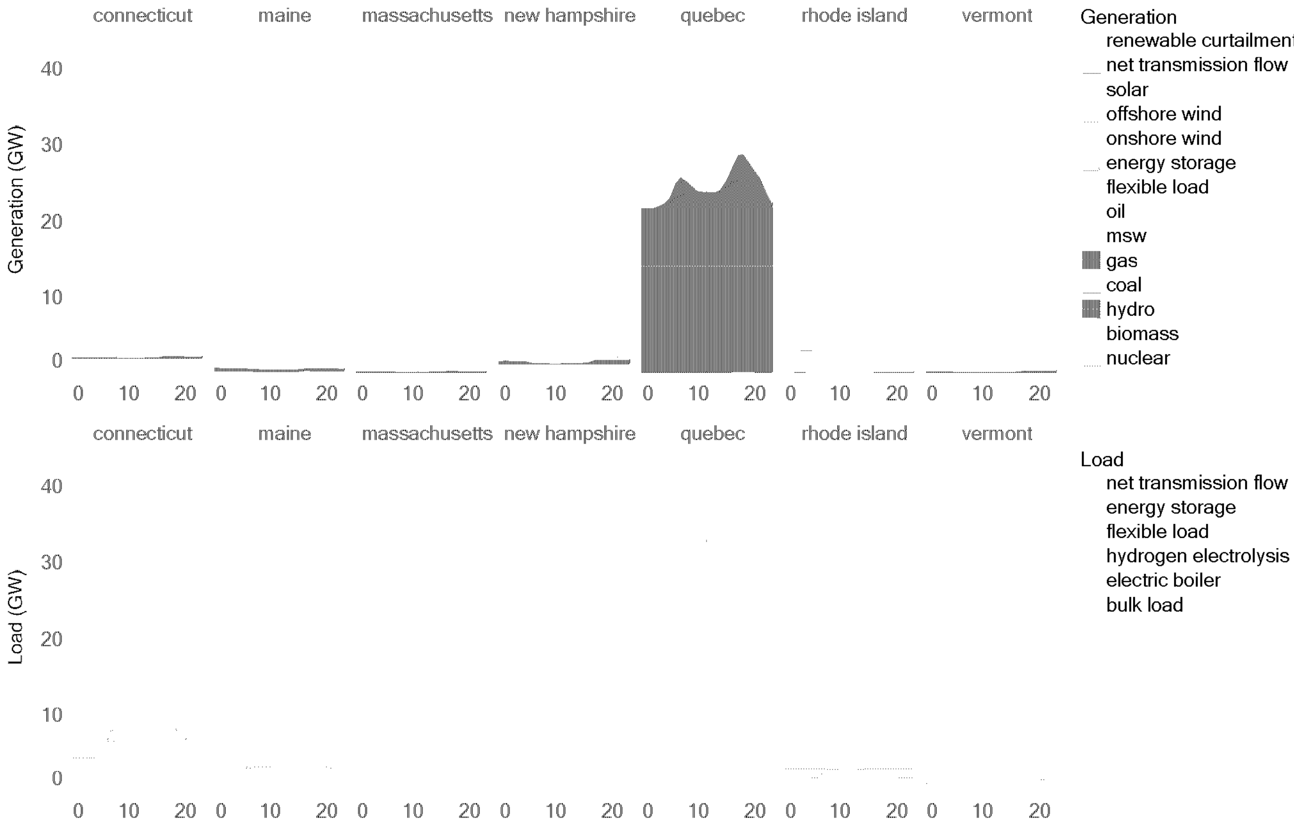


Figure 26 shows average hourly operations in the All Options pathway for the six New England states plus Quebec. The patterns of renewable production (top panel) show that solar and offshore wind generation have complementary profiles to some extent. Curtailment of renewable generation occurs primarily during daytime hours; bulk storage works to shift some of the surplus solar energy to the evening peak. Flexible load, primarily EV charging (but also distributed customer-side batteries and flexible end-uses), results in a significant reduction in load during the evening; this load is spread across the night-time hours. Quebec exports are highest outside of daytime hours with a peak in the evening. On the load side (bottom panel) electrolysis and electric boiler loads are operated to complement renewable output. As discussed in the next section on renewable balancing, the average day profile is useful for understanding broad patterns of generation and annual carbon emissions. However, across the year there is significant day-to-day variability in renewable resource production, and consequently in the operation of dispatchable resources. Understanding the patterns of variability is essential for explaining many parts of the system, including the role of thermal capacity and other balancing resources (Figure 24) in system reliability and economics.

Figure 26. Daily average electricity operations in the All Options pathway, by zone. (Top) Generation, imports, storage discharge, and curtailment. (Bottom) Load, imports, and storage charging. Flexible load on the generation side represents a reduction in bulk load. The hours to which this load has been shifted is shown in the same color in the load panel. Because an average value for all days is displayed, artifacts of the diversity between days are apparent in the figure. For example, in Massachusetts at mid-day, renewable curtailment and transmission imports can both be seen occurring in the same hour; however, in actuality, both do occur, but on different days.



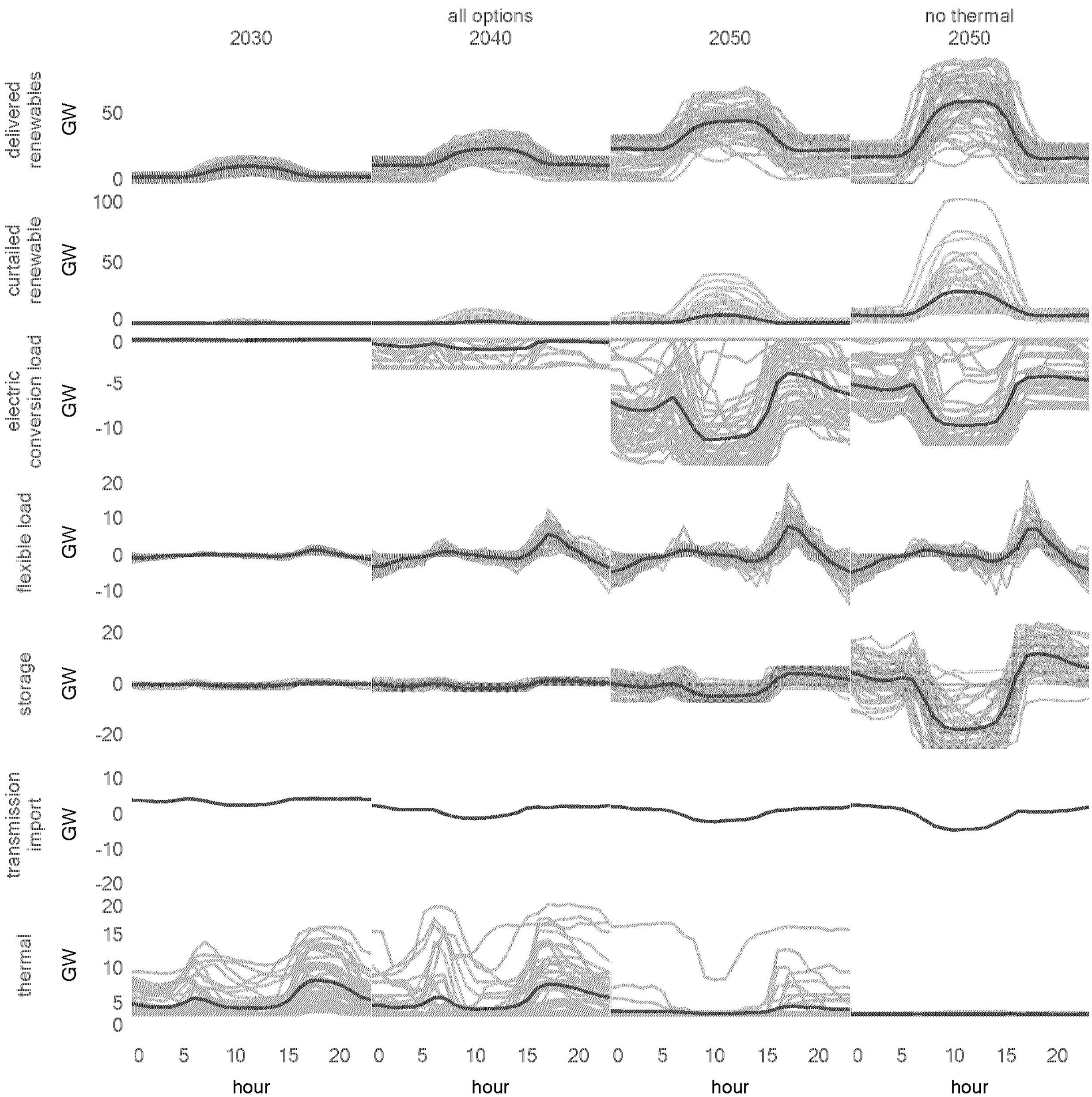
5.4.3 Operations and renewable balancing

The electricity systems in all the pathways studied had high penetrations of wind and solar generation, as described in the previous section. This outcome was not pre-ordained, but was the solution selected by the RIO optimization model for the lowest cost electricity system consistent with the net-zero emissions target. However, although wind and solar generation have substantially lower levelized cost of energy than any other technology considered, they do present unique operational challenges due to their variability. “Renewable balancing” is the term that describes the operational measures used to address the mismatch between variable renewable supply and must-serve load. Sometimes renewable supply is far in excess of load, leading to curtailment of renewable generation and reducing the economic competitiveness of these resources. At other times, a shortfall of renewable generation on the system results in the need for dispatchable resources to maintain system reliability. System operators must forecast both surplus and deficits, or “net load,” with sufficient lead time to apply a suite of tools that enable the system to maintain reliability while meeting carbon constraints at low cost.

The deployment of each of these balancing tools, aggregated for all of ISO-NE, is shown in Figure 27. The first three columns show the All Options pathway in 2030, 2040, and 2050. The right-most column shows the No Thermal pathway in 2050, in order to illustrate the measures required to replace all thermal power plants without harming reliability. In each row of the chart, a series of translucent colored lines is shown, one for each of the 45 sample days used by RIO. The solid black line is the average of all the sample day values.

The top row of the chart shows delivered renewables and the second row shows curtailed renewables, with the sum of the two being total generation potential. Although various balancing strategies are applied to minimize curtailment, curtailment is also a critical balancing strategy. Designing a system to have no curtailment would significantly increase overall system cost because (1) it would have a lower renewable capacity build, resulting in a larger generation deficit, and a consequent need for other, more costly generation resources, at times of the year when load exceeds renewable generation, and/or (2) it would require overbuilding other balancing resources such as energy storage that are expensive and would be infrequently utilized on the margin.

Figure 27. ISO-NE renewable balancing in the All Options pathway in 2030, 2040, and 2050, and in the No Thermal pathway in 2050. Each sample day (45 total) is shown using stacked colored lines with the average across all sample days shown in black. Note that the scale is different for each row. Negative values indicate storage charging or an increase in load while positive values indicate generation or a decrease in load.



The third row of Figure 27 shows electric conversion loads. These are electric boiler and electrolysis loads that are large (5-10 GW on average in 2050) and are not must-serve. Electric boilers are built in a dual-fuel configuration that allows use of gas when electricity is not available or not at the desired price. Hydrogen can be stored, blended into the pipeline, or produced by other methods, including imports, when not available via electrolysis. As evident in the figure, on some days electric conversion loads do not operate at all, and on other days they average 10-15 GW during most of the day. The importance of this conversion load strategy for high renewables power systems cannot be overstated. By providing a productive use for surplus renewable generation on days with low loads, additional renewable capacity can be built to provide energy at times when there would otherwise be larger renewable deficits. Put another way, conversion loads enable a strategy of "overbuilding" renewables that permits wind and solar to be utilized to the maximum extent for the energy system as a whole.

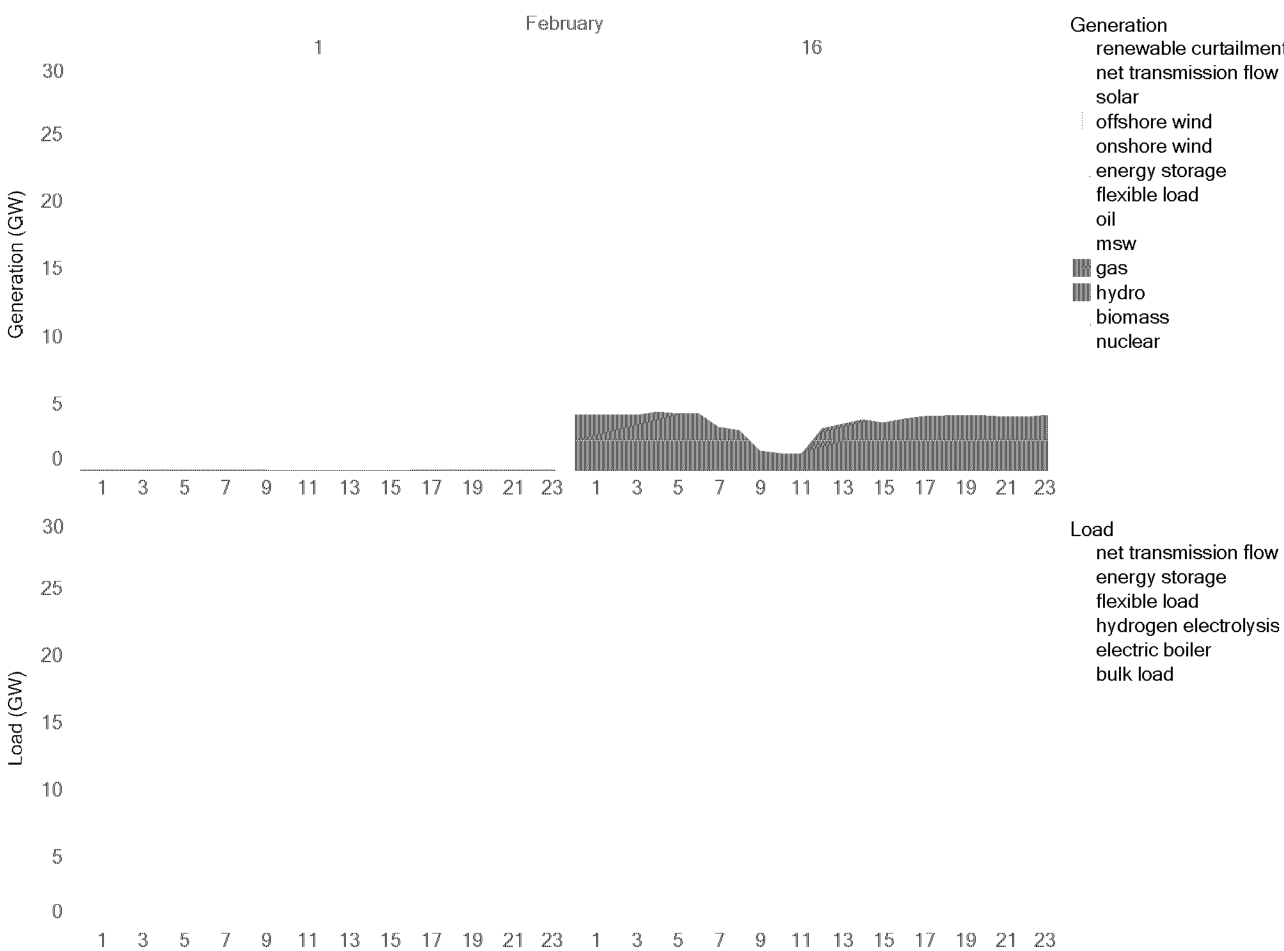
The fourth and fifth rows show flexible load and energy storage. Both show values above and below the x-axis, with positive values representing storage discharge or a reduction in load, and negative values indicating storage charging or an increase in load. The main source of flexible load is delayed EV charging, moving the charging load out of the 5-8 pm window to the middle of the night. The flexible use of space heating is also apparent in a narrow morning spike. The diurnal EV and heating loads modeled here do not have the flexibility to shift load into the middle of the day when solar is available; this is where energy storage is most critical. Energy storage discharges, on average, during nighttime hours with a large discharge peak in the evening and a smaller peak in the morning. Storage dispatch in the No Thermal pathway dwarfs that in the All Options pathway. The large amount of storage required to maintain reliability in the No Thermal pathway also competes with electric conversion loads for the use of renewable over-generation, which is why there is lower conversion load in this pathway. The state of charge over the course of the year for the long-duration storage built in the No Thermal pathway is shown for Massachusetts in the technical supplement, Figure 54.

The second to last row of Figure 27 shows net transmission flow into (positive) and out of (negative) ISO-NE. Over time, transmission flows become increasingly variable as a way of compensating for mismatches between renewable supply and generation, and the magnitude of the flows grow with transmission capacity, as discussed in Section 5.4.4. All pathways use the Quebec hydro system in effect as a form of seasonal energy storage, with energy exported to Quebec during many hours to serve Quebec loads, and with imports from Quebec in other hours to serve loads in New England and New York. Because it lacks thermal generation, dispatchable hydro capacity is of especially high value in the No Thermal pathway, and it therefore builds larger interties to Quebec than in any other pathway. No Thermal is also the only pathway in which it was found economical to build new hydro in Quebec beyond that which is already assumed. The hydro capacity build in Quebec is shown in the technical supplement, Figure 56.

The bottom row shows the operation of gas thermal power plants. An interesting trend emerges from 2030 to 2050 period, as the average daily use of gas capacity (shown by the solid black line) decreases, but maximum daily use increases. In the All Options pathway in 2050, one sample day in particular stands out from the rest (the uppermost translucent grey line). On this day, the electricity system requires almost 15 GW of thermal generation, dispatched across all hours, to maintain reliability. It is the effort to replicate this level of sustained energy production—potentially over multiple days in a row during a prolonged wind drought—that requires a very large amount of energy storage in the No Thermal pathway.

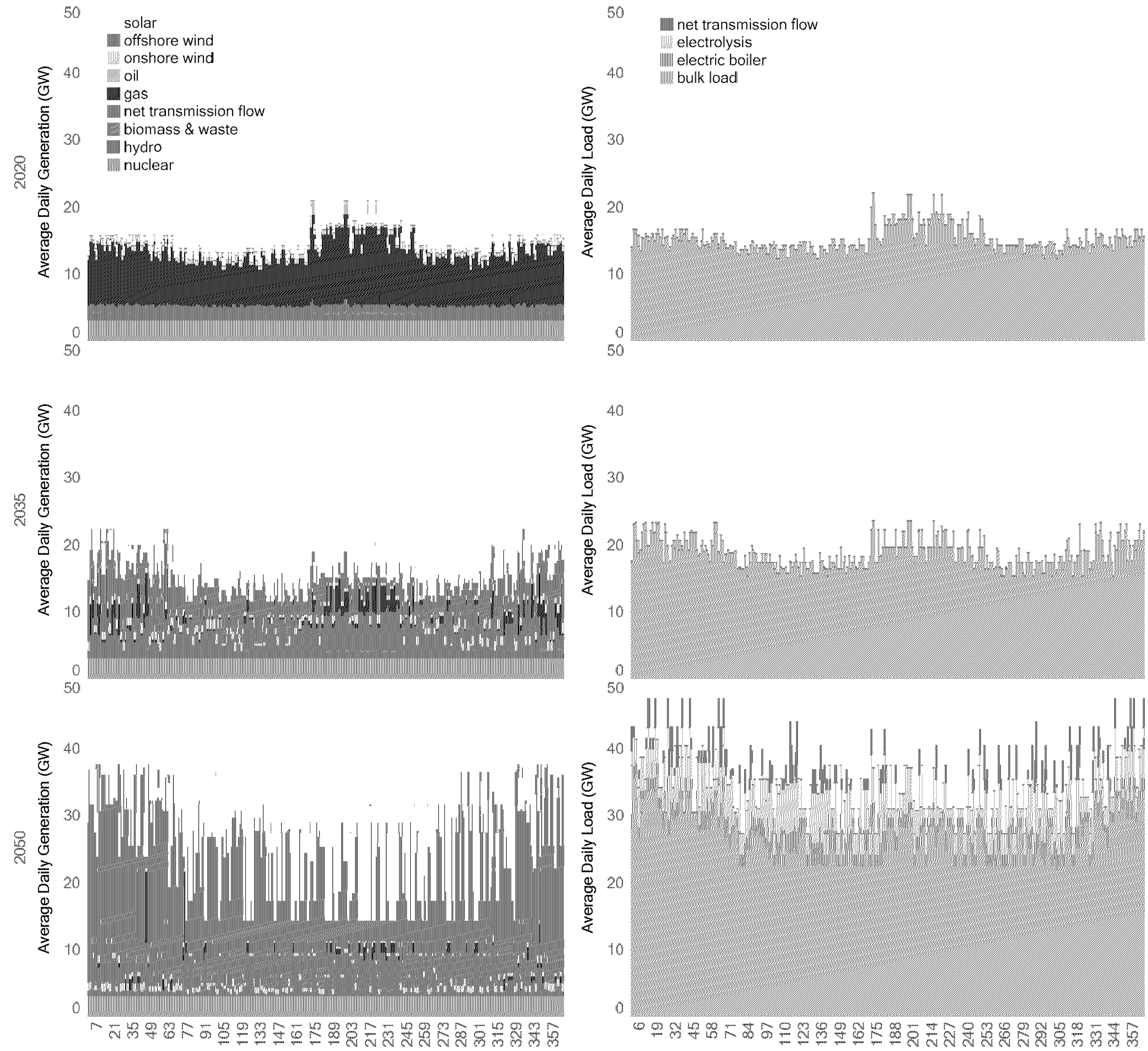
The sample day with 24 hours of gas thermal dispatch is February 16th. Figure 28 contrasts this day with February 1st from the same 2012 weather-year for the All Options pathway in Massachusetts. On February 1st, the output of offshore wind is close to its nameplate capacity for the entire day. The system is balanced by exporting energy to surroundings ISO-NE states and to Quebec and operating electrolysis and electric boiler loads. Two weeks later, on February 16th, the lowest offshore wind production of the year occurs. On this day, gas generation is needed in every hour of the day in combination with the maximum possible transmission imports from Quebec. Solar production is significant for a winter day, but still far too small to meet total energy demand. Any loads that are not "must-serve" are turned off during the day, so there are no electrolysis or electric boiler loads on this day. While keeping thermal generating capacity online when it is infrequently used may seem inefficient when viewed from the perspective of its contribution to annual energy production (Figure 23), the steps required to maintain today's electricity system reliability without this capacity on days like February 16th turn out to be extremely costly. Solar shows less day-to-day variability than offshore wind in New England, which is the primary reason for the large overbuild of solar in the No Thermal pathway. By greatly increasing solar generation on February 16th, the amount of energy to be provided by energy storage can be reduced. The flip side of this strategy occurs during other times of the year when up to 100 GW of renewables are curtailed at once across the region (Figure 27). Across New England, 25% of potential renewable generation is curtailed in the No Thermal pathway, compared to about 4% in All Options.

Figure 28. All Options pathway daily operations for Massachusetts in 2050. February 1st (a high offshore wind generation day) is contrasted to February 16th (lowest offshore wind day of the year). Generation is shown in the top panel and load in the bottom panel.



To further illustrate the operational implications of the sample days discussed above, average daily generation and load in ISO-NE across 365 days in 2020, 2035, and 2050 (based on the 2012 weather year) is shown in Figure 29.

Figure 29. Average daily energy generation and load in the All Options pathway for ISO-NE in 2020, 2035, and 2050, based on the 2012 weather year. Electricity supply is on the left and load on the right. Net transmission flows on the supply side represent net daily imports, and on the load side represent net exports. Energy storage is omitted in the figure because in all pathways except No Thermal, only small amounts of energy are shifted between days. From an daily energy perspective, storage appears primarily as a load, representing round-trip losses.



The three snapshot years illustrate the trends discussed so far. In 2020, gas generation follows load, oil generation is used on peak days, net daily imports occur on every day of the year, and the days with highest average energy consumption are in the summer. Renewables are meaningful but still small. In 2035, the system has winter days with load equal to that of summer peak days, and yet overall load has not yet grown substantially. Sales shares of electric technologies are high, as described in Section 5.3 and Figure 14, Figure 15, and Figure 17, but the stock itself is not yet highly electrified. High levels of solar and offshore wind are apparent in 2035 and while exports from ISO-NE are not yet seen, imports to ISO-NE vary significantly across days as a function of load and renewables. Days of high thermal power plant use can be seen throughout the year, concentrated mainly during summer and winter peaks. Finally, in 2050 the full set of balancing strategies is on display. Final energy demand has grown dramatically as electric technology stocks finally reach saturation levels. Renewable generation has also grown dramatically. Large electrolysis and boiler loads, and exports from ISO-NE, occur on days with surplus renewables. There are many days in which no thermal capacity is used, but there are also numerous days in all seasons, especially in winter, that require significant use of thermal capacity. Imports are even more sporadic than in 2035, and while it is clear that transmission lines are utilized extensively, net imports over the course of the year have actually shrunk because power is flowing in more equal quantities in both directions. In the next section we will examine transmission in greater detail.

5.4.4 **Transmission and distribution**

This study analyzed the role of, and impacts on, the transmission and distribution (T&D) system in the process of deep decarbonization. Four categories of T&D were considered:

- New inter-regional transmission between states, or between Canada and the US: This transmission is solved for explicitly in RIO as part of the capacity expansion modeling and is co-optimized with other supply- and demand-side resources.
- Distribution circuit upgrades (residential, commercial, industrial) within each zone: Simultaneous peak load by customer class was calculated, and the distribution revenue requirement for each class was scaled according to peak load growth.
- Transmission upgrades within each state, treated separately from lines between states (for example, new transmission into Boston from other part of Massachusetts). The simultaneous gross load peak in each state is pegged to the current revenue requirement, and scaled with peak load growth. It is assumed to be additive with new inter-regional transmission.
- Renewable interconnections and spur lines to connect solar and wind to load: New lines to connect renewables to load or the nearest available transmission. This category includes lines to connect offshore wind.

The latter two categories (in-state bulk transmission and spur lines) are not explicitly addressed in this section, but are included in the cost estimates in Section 5.6. The first two categories are examined in more detail below.

5.4.4.1 Inter-regional transmission

New inter-regional transmission was a critical part of all pathways because of its importance as a balancing strategy in high renewables systems. Its value stems from three factors: weather diversity across zones, complementary resource endowments, and the flexibility of the Quebec hydro system. Figure 54 in the technical supplement shows a map of the transmission lines modeled in RIO and contrasts the 2050 transmission capacity in six pathways, including the reference case. In all pathways, the transmission paths from Quebec to New York, and from Quebec to Massachusetts, had significant new capacity build. In the No Thermal pathway and the Regional Coordination pathway, significant new capacity was also built from New York to PJM. Beyond these major transmission paths, numerous smaller upgrades were made within New England and between New England and New York. Table 8 shows the cumulative transmission build in each of the studied transmission paths. The net-zero scenarios with the highest total regional transmission build are on the left side of the table, and those with the lowest total build are on the right side. Massachusetts does not always follow the regional trends. The highest builds occurred in the No Thermal, Regional Coordination, and

Limited Efficiency pathways. The lowest total regional build occurs in the Offshore Wind Constrained pathway in which regional nuclear capacity additions in New York and Connecticut reduce the need for renewable balancing. New lines were built from Massachusetts to every neighboring state, except for Vermont, in some but not all pathways. The most frequently built lines for Massachusetts strengthened connections to Quebec, New Hampshire, and New York. The line to Quebec is the only Massachusetts transmission line built in all pathways, with a minimum capacity of 2.7 GW and a maximum of 4.8 GW.

Table 8. Cumulative transmission build 2020-2050 by pathway. The 17 modeled transmission paths are assumed to be symmetrical, meaning that 3.7 GW from New Hampshire to Massachusetts also implies operational capability of 3.7 GW from Massachusetts to New Hampshire.

Zone from	Zone to	no thermal	regional coordination	limited efficiency	100% renewable primary	all options	der breakthrough	pipeline gas	offshore wind constrained
Connecticut	Rhode Island	0.5	0.9	1.3	1.6	0.3	0.3	0	0
Massachusetts	Connecticut	1.5	0.1	0	0.2	0	0	0	0
Massachusetts	Rhode Island	0.5	0	0	0	0	0	0	0
Rest of US	New York	7	6	3	1.5	0	0	0	0
New Brunswick	Maine	2.7	0.5	0.1	0.8	0	0	0	0.1
New Hampshire	Maine	3	1.8	1.2	1.5	1	0.9	0.9	0
New Hampshire	Massachusetts	3.7	2	1.6	0.2	0.6	1.3	0	0
New York	Connecticut	1.5	1	0.8	0.8	0.6	0.5	0.5	0.5
New York	Massachusetts	2.6	2.5	1.5	1.5	1	1.2	0	0
New York	Vermont	0.4	0.4	0	0	0	0	0	0
Quebec	Maine	2	1.2	1.1	0.9	0.6	0.6	0.6	0.9
Quebec	Massachusetts	4.3	4.8	3.7	3.3	2.7	2.8	3.1	3.9
Quebec	New Brunswick	0	0	0	0	0	0	0	0
Quebec	New York	6.8	6.8	6.8	4.7	4.4	4.2	5.6	3.8
Quebec	Vermont	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8
Vermont	Massachusetts	0	0	0	0	0	0	0	0
Vermont	New Hampshire	0	0	0	0	0	0	0	0
	Sum	37.3	28.7	21.9	17.8	12	12.6	11.5	10

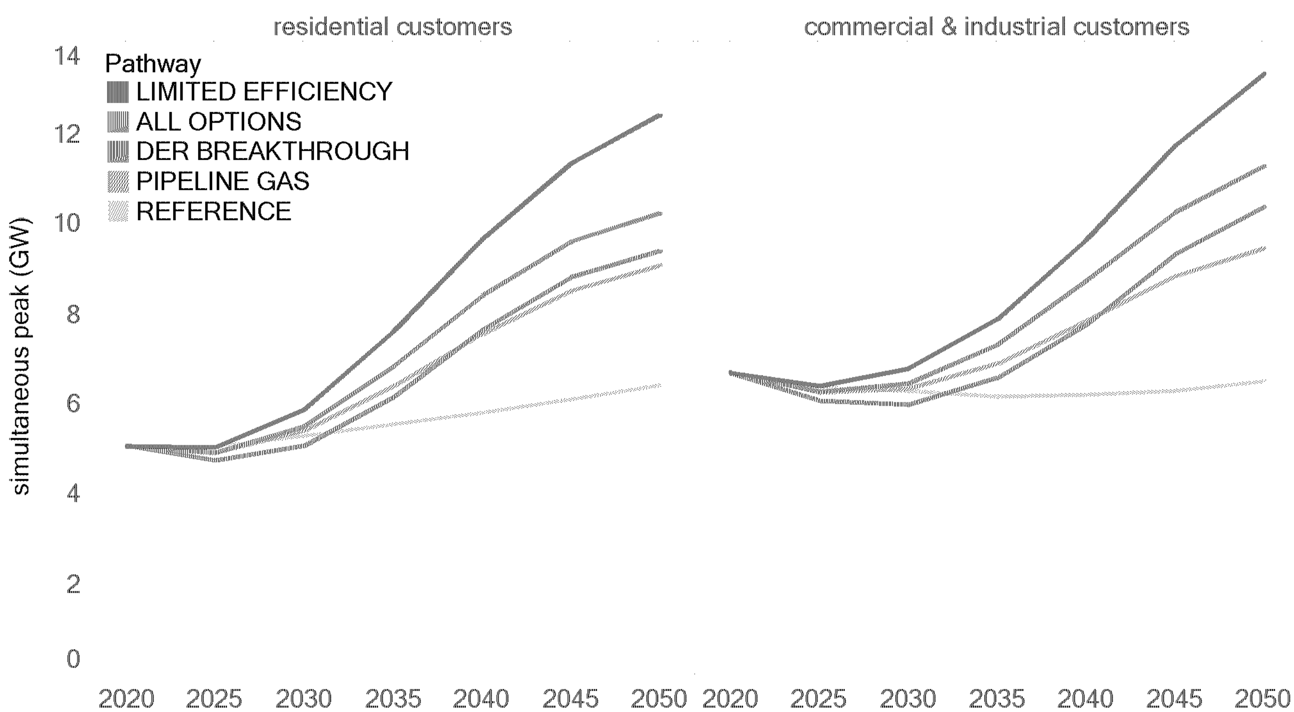
5.4.4.2 Electricity distribution

Electricity distribution cost is the largest single component of the average customer's electricity bill (see Figure 36 with average rate estimates). Because of this, and the significant impact of electrification on distribution peak load, understanding what drives distribution upgrade cost is very important. Highly resolved data on individual circuits would be required to specify exactly what upgrades would be required for a given pathway in a specific location at a specific time. Since this was not practical for the present study, we took an alternative top-down approach, calculating simultaneous peak demand across Massachusetts and then scaling revenue requirements to this peak. The methodology is discussed in further detail in Section 7.7, and the cost results for the distribution system are presented in Section 5.6.

The Massachusetts simultaneous peak load by customer class is shown in Figure 30. Commercial and industrial customers have been grouped. This figure is related to the hourly electricity profiles shown in Figure 21. Because the All Options, No Thermal, Regional Coordination, 100% Renewable Primary, and Offshore Wind Constrained pathways all have identical demand-side assumptions, the distribution build is identical, and they are represented by the All Options pathway.

All pathways have significant increases in distribution peak load. The impact of low building electrification can be seen in the lower peaks in Pipeline Gas pathway compared to the All Options case. The DER Breakthrough pathway also has lower peaks, showing the value of additional flexible end-use loads. On the other hand, the Limited Efficiency pathway has much higher winter heating loads and a substantial increase in distribution peaks.

Figure 30. Massachusetts coincident peak load by aggregate customer class, residential (left) and commercial and industrial (right). Projections of future distribution costs are based on the ratio of the existing revenue requirement to the existing peak.



5.5 Fuels and carbon management

Despite high levels of electrification in all pathways, legacy fuel demand in 2050 was between 25% and 40% of current levels. The majority of this fuel was in the form of hydrocarbons such as jet fuel, asphalt, and pipeline gas. In general, the remaining fuel uses were difficult or uneconomic to electrify or to replace with hydrogen. Since fuel use is unavoidable, developing a sustainable and cost-effective strategy for Massachusetts to procure fuels that are consistent with a net-zero pathway is essential. Today, Massachusetts imports all of its fuels, except some biomass, solid waste and land-fill gas, from out-of-state. Because Massachusetts has limited biomass supplies and limited available land, it is infeasible to produce all fuel needed by the state within its boundaries. Nonetheless, in all pathways modeled, a much higher proportion of fuel consumed was produced in-state than is the case today.

In all modeled pathways, importing net-zero carbon fuels to supplement domestic fuel production commenced only after 2040 because of the high assumed cost of these fuels. As discussed in Section 6.2.3, the marginal fuel costs used here reflect the assumption that the United States as a whole is decarbonizing, and that there are multiple regions and multiple end uses competing for a limited supply of biomass. However, the question of decarbonized fuel supply may need to be addressed before 2040 for several possible reasons, including the potential that: (a) emission reductions in electricity occur at a slower pace, requiring earlier fuel decarbonization in order to reach emissions targets in intermediate years; (b) imports of decarbonized fuels are available at lower cost early on than assumed in this analysis, because fewer jurisdictions are initially competing for them; or (c) developing markets for fuels are needed earlier in order to stimulate technological progress and to clarify the pace and scale of electrification required. The remainder of this section focuses on the fuels needed in 2050, but with the caveat that these results may be relevant well before then.

5.5.1 Fuel production within Massachusetts

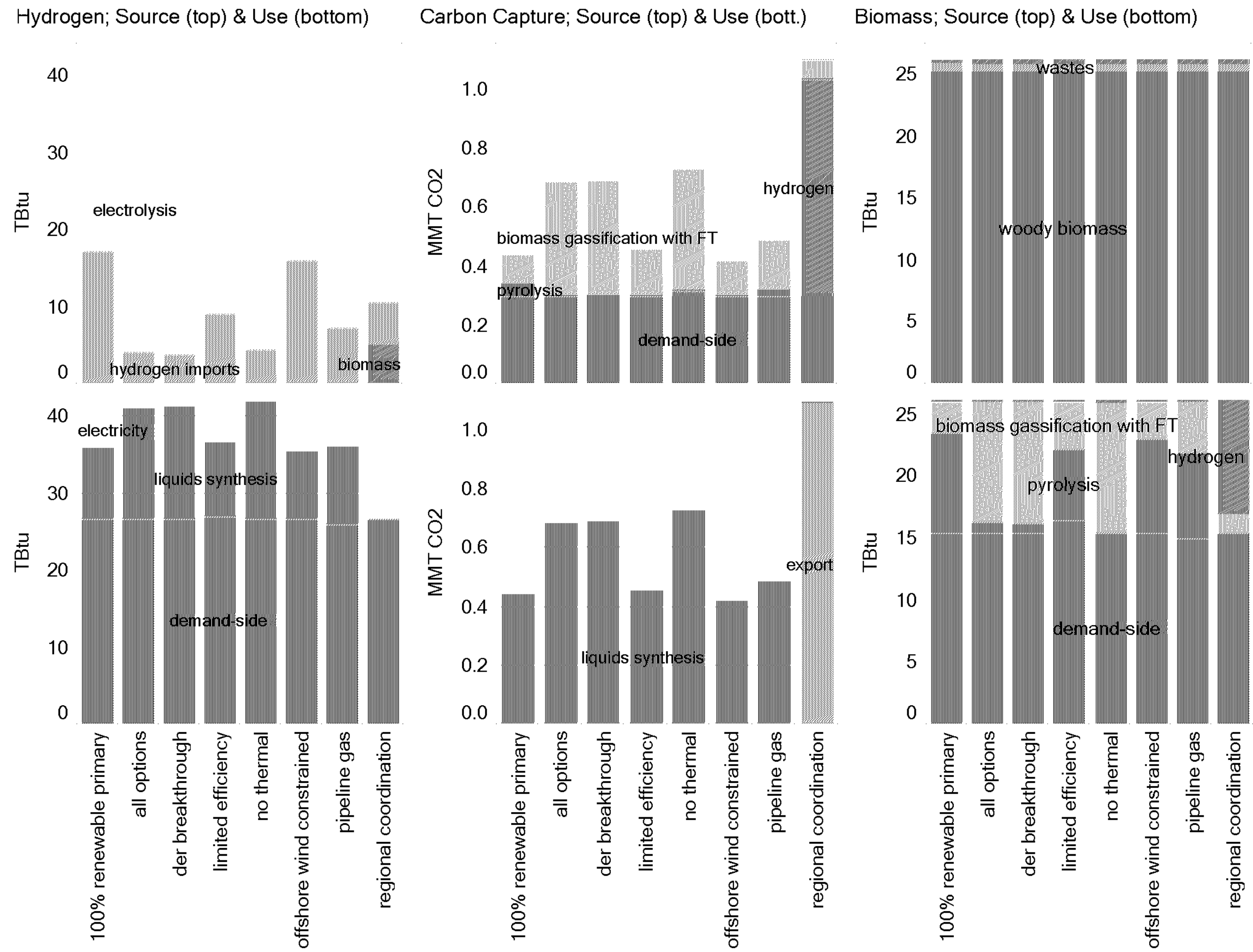
Fuel production within Massachusetts requires hydrogen, captured carbon, or biomass, since all fuels ultimately need one or more of these components. Figure 31 shows the sources (top row) and uses (bottom row) of each of these fuel components across all pathways.

Hydrogen: The source of hydrogen was primarily in-state electrolysis, with differing amounts of hydrogen imports depending on the pathway. Most of the hydrogen produced was used to meet final energy demand in the transportation sector. Secondary uses of hydrogen included synthesizing liquid hydrocarbon fuels with carbon captured in Massachusetts, and to a very limited extent, direct combustion in thermal power plants.

Captured carbon: Much of the carbon came from the industrial sector in which carbon capture technology is used in the production of lime. Captured carbon also came from biorefining processes—pyrolysis, gasification with Fischer-Tropsch (FT), and hydrogen production from biomass—all of which produce CO_2. In the Regional Coordination pathway, captured carbon was exported for geologic sequestration at a cost of \$71/tonne CO_2. In all other pathways, captured carbon was utilized, being combined with hydrogen to make more liquid fuels. The Fischer-Tropsch process for gasified biomass was also used to synthesize liquid fuels. This could be visualized as occurring in an integrated process that does not involve transporting captured carbon, but rather combining biomass refining, hydrogen production, and fuel synthesis in a single location or facility. Issues surrounding carbon recycling (e.g., double-counting carbon emission abatement from capture and re-use), carbon life-cycles (e.g., especially for determining biomass harvest sustainability), and implications for GHG emissions are discussed in greater detail in the Roadmap Study Report.

Biomass: In the modeling, almost all biomass in Massachusetts came from wood, and the biomass that was not used in biofuel production went primarily to residential heating. In the optimization, the biomass that is used in electricity generation today is diverted into synthetic fuel production, because the avoided cost for zero-carbon electricity is relatively low, whereas the avoided cost for imported net-zero carbon liquid fuels is high. Thus, diverting existing biomass away from electricity and towards liquid fuels provides greater value-added for plant owners.

Figure 31 Massachusetts sources and uses of hydrogen, carbon capture, and biomass in all pathways in 2050.



5.5.2 **Net-zero carbon fuel imports**

The majority of residual hydrocarbon fuel used in 2050 comes from imported fuels that are assumed to be net-zero carbon. Figure 32 shows the quantity of carbon neutral hydrocarbons imported into Massachusetts in 2050 in four pathways; it also compares these to existing ethanol imports in 2020 in order to give scale.[44]

In the All Options pathway, decarbonized fuel imports expanded only slightly from 22 TBtu in 2020 to 31 TBtu in 2050, but the composition of the imports shifted away from ethanol (because gasoline-type fuel use is greatly reduced by electrification) and towards jet fuel, which was still in use on the demand side. In the Limited Efficiency pathway, the lack of efficiency improvements in aviation and other fuel end uses resulted in a doubling of decarbonized fuel imports. Finally, in the Pipeline Gas and 100% Renewable pathways, significant additional decarbonized imports were needed to meet greater demand for both liquid fuels and pipeline gas. In all pathways, carbon neutral fuels were first imported to replace petroleum products, and second to replace natural gas, since natural gas is much less expensive and has lower carbon content.

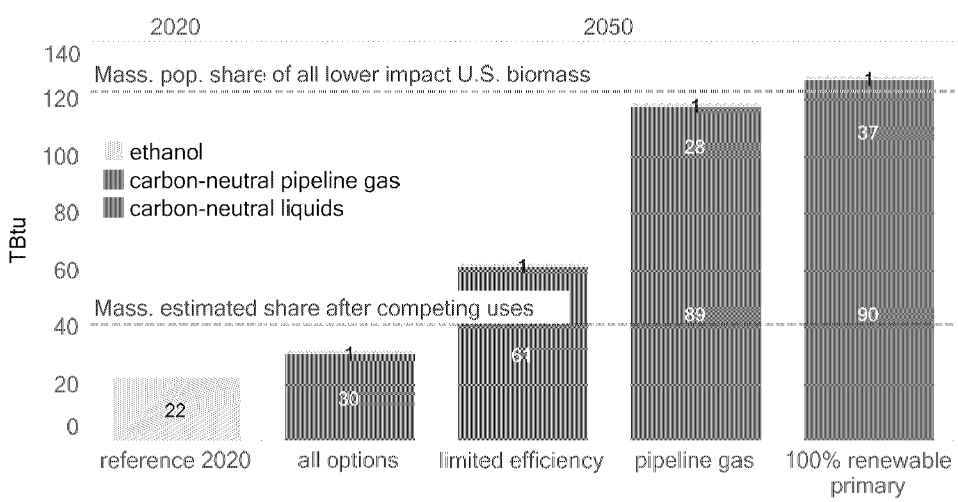
[44] Assumes Based on an average ethanol blend of 7% by energy content in gasoline.

The orange dotted line in Figure 32 gives an estimate of Massachusetts' population share of all sustainable U.S. biomass use. Sustainable biomass use nation-wide is estimated at 12 quads/year, based on the assumption that this amount requires no additional land to be put into cultivation for biomass production.[45] The 12 quads of biomass feedstock were used to make 6 quads of processed fuels, of which the Massachusetts population-weighted share is 2.06% or 123 TBtu/year.

Nationally, certain uses like feedstocks in the chemical industry require carbon, and thus, fuel combustion will frequently not be the highest value-add for our limited biomass resources. Most of these uses are also located outside of the Northeast. National feedstock demand for organic chemicals and plastics is estimated at 4 quads/year in 2050. Some of this could still be supplied with fossil petroleum; however, in the extreme, if it is assumed that four quads of the six available are reserved for competing uses, the available sustainable biomass supply is likely to be closer to 41 TBtus/year for Massachusetts. This level is shown with a dotted grey line is shown in Figure 32.

Of the eight pathways, three pathways exceed this 41 TBtus/year threshold, while five fell below it (in figure 32, below All Options is the only one of those five pictured). As discussed in Section 6.2.3, further research is needed to understand the economic and sustainability implications of the fuel import levels found in each of the pathways. In the meantime, pathways over-relying on large quantities of these fuels should be understood to carry a significant risk that they will not be available in 2050 at high quantity (or that such quantities would come with a high price or other external costs, including equity and environmental justice considerations).

Figure 32. Massachusetts imports of carbon-neutral liquid hydrocarbons and methane (pipeline gas). These fuels are made in the rest of the U.S. (or internationally) for export to Massachusetts and the rest of the Northeast using technologies that imply carbon neutrality.[46] The dotted line represents Massachusetts's population share of U.S. biomass production that limits purpose-grown feedstocks to the same land footprint currently used for ethanol production, plus all available crop wastes and residues.



[45] Princeton Net-Zero America Project, 2020 (forthcoming)

[46] To be carbon neutral, the carbon contained in the hydrocarbon fuel must either be come from directly captured from the atmosphere, gained from biomass, or else its combustion emissions must be captured and sequestered or offset with a negative emissions technology and geologic sequestration. The production of carbon neutral fuels has been explored extensively at a national level using the RIO model and these insights have been leveraged in the representation analysis of fuel imports for the Northeast.

5.6 Cost

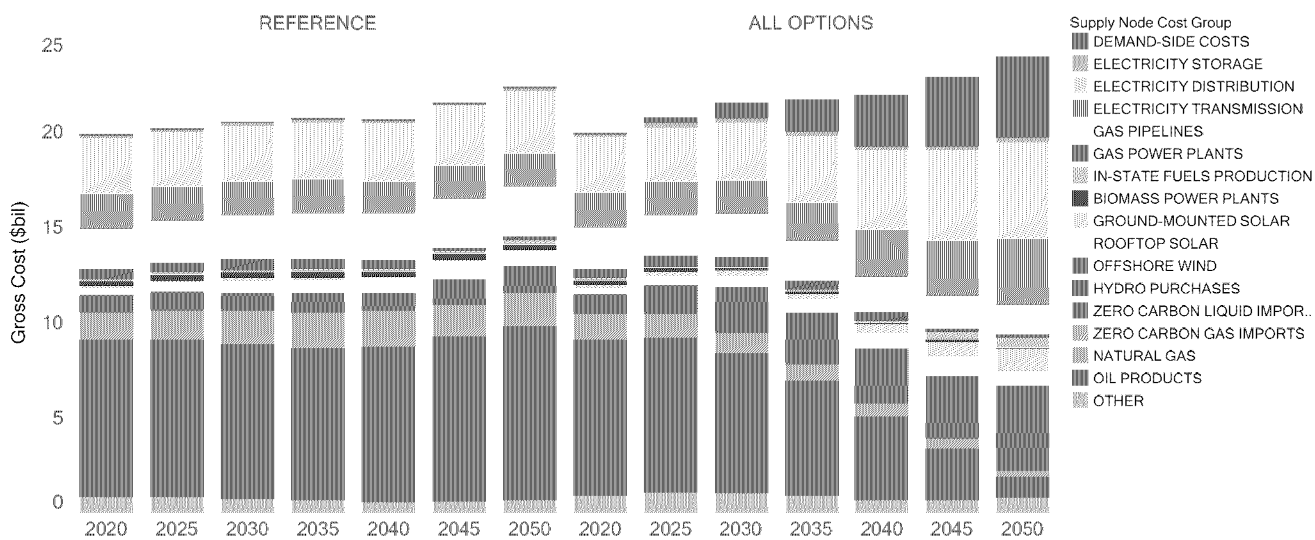
This section presents energy system cost estimates for each pathway studied. As noted in Section 3.1.3 on cost methodology, the indirect effects and co-benefits of pursuing a net-zero emissions policy for the region—including employment and public health benefits—were quantified in a follow-on analysis, the results of which are presented in the Roadmap Study Report. This study did not attempt to quantify the avoided damages from climate change and thus does not comment on the appropriate value of a "social cost of carbon." This section focuses only on spending for energy and demand-side equipment needed to reach the Net Zero goal.

5.6.1 **Gross cost**

Figure 33 shows annual total spending on energy in Massachusetts in the reference case and All Options net-zero pathway. Currently roughly half of gross spending goes to the purchase of petroleum products and natural gas, and the other half goes to capital expenditures either within Massachusetts or allocated to Massachusetts in markets like ISO-NE. Energy delivery infrastructure for both electricity and natural gas represent the majority of current in-state capital expenditures on energy. The capital cost of current power plants is a small share of total spending. All capital costs shown are levelized, meaning the full cost of the powerplant is not seen in the year it is built, but instead paid in installments over the book life of the asset.

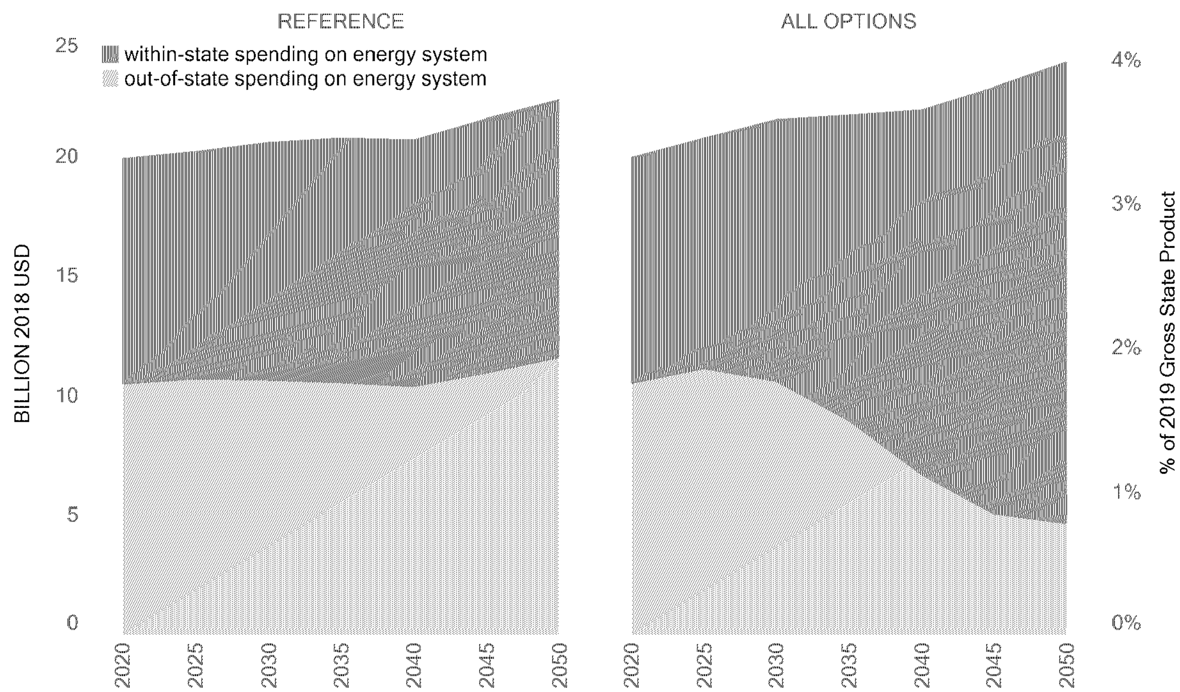
In a decarbonized energy system, spending shifts away from fossil fuel purchases towards new capital equipment. The All Options pathway in Figure 33 illustrates this transition. At the top of the figure in red is the incremental demand-side cost above the reference case cost, including the incremental cost of efficiency and electrification, as represented by, for example, building envelope retrofits, heat pumps, and electric vehicles. Spending on electricity delivery infrastructure increases due to electricity load growth, while gas pipeline spending decreases by a modest amount. The decrease in gas pipeline revenue requirement and the assumptions that went into this are further discussed below. Spending on renewables increases in all years and the cost of net-zero carbon fuel imports becomes significant in 2050. Gross energy system costs for all pathways in 2050 are presented in the supplemental materials, Table 19.

Figure 33. Massachusetts gross energy system cost in the Reference (no decarbonization) and All Options pathway, broken out by cost component. For scale, twenty billion dollars is 3.3% of current gross state product. All costs are shown in real 2018 dollars.



One effect of the shift in energy system spending towards capital equipment is that a much larger share of energy expenditures stay within Massachusetts. In-state vs. out-of-state spending is shown in Figure 34. In the net-zero case, spending for energy purchases out-of-state is cut in half while in-state spending roughly doubles. The right-hand axis in Figure 34 compares gross energy spending in the reference case and All Options pathway to the 2019 Massachusetts gross state product (GSP). Historical energy spending has, at times, been a much higher fraction of GSP than the 2050 cost of a net-zero energy system, as a function of oil price fluctuations. An additional, unquantified, benefit from decarbonization is the insulation from oil price shocks, which have often been the precursors to economic recessions over the past 50 years.

Figure 34. In-state vs. out-of-state spending on energy for the reference and all options pathways, in dollars and as a percentage of 2019 gross state product ($600B).



5.6.2 Net cost by scenario

This section presents annual levelized net costs for all pathways, using the All Options pathway for comparison. Figure 35 summarizes the net cost by year and Figure 36 shows a detailed breakdown of relative cost by component. In Figure 36 cost components shown above the x-axis are incremental to the All Options cost, while costs below the x-axis are savings. The labeled black circles show the net cost from summing the component cost increases and decreases and match Figure 35. Pathways are ordered based on energy system cost in 2050, and roughly form three clusters.

In the first cluster are the DER Breakthrough, Regional Coordination, and Offshore Wind Constrained pathways, which have only small positive or negative net costs relative to All Options. The DER Breakthrough pathway has additional costs for rooftop PV but saves the cost of ground-mounted PV and also saves transmission and distribution (T&D) cost. The T&D cost savings come from the flexible end-use load as reflected in Figure 30 showing simultaneous distribution peak load by customer class. The Regional Coordination pathway allows greater out-of-state electricity imports in the near- and medium- term and also allows a combination of fuel system changes that save modest cost in 2050 due to the ability to export CO_2 for sequestration. In other words, the ability to export CO_2 for sequestration, when captured, was found to be slightly cheaper than deploying additional mitigation options elsewhere. Both the DER Breakthrough and Regional Coordination pathways are slightly lower net cost than the All Options pathway. The Offshore Wind Constrained pathway has small net cost increase. As expected, out-of-state energy purchases increase in this pathway, while in-state spending on offshore wind is decreased.

Figure 35 Massachusetts net energy system cost for all net-zero pathways compared to the All Options pathway. Costs above the x-axis represent incremental costs above All Options. Costs below the x-axis represent savings compared to All Options.

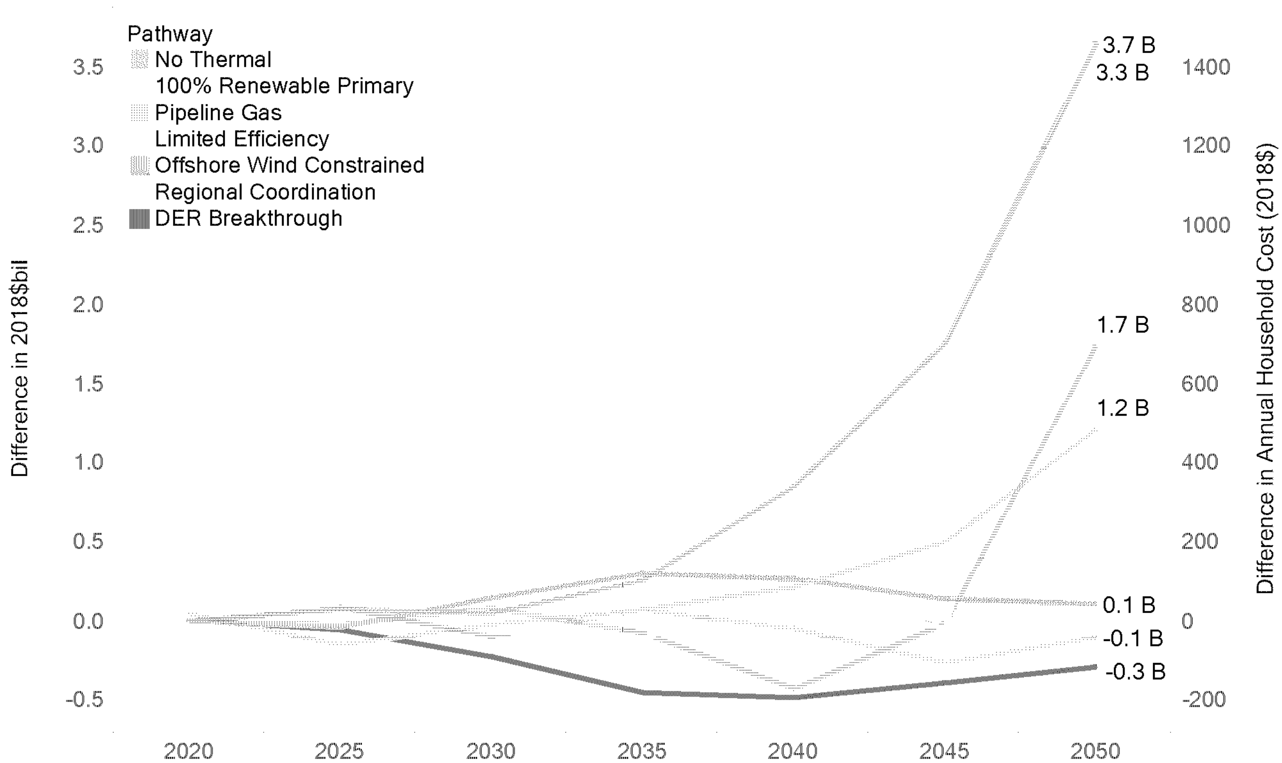
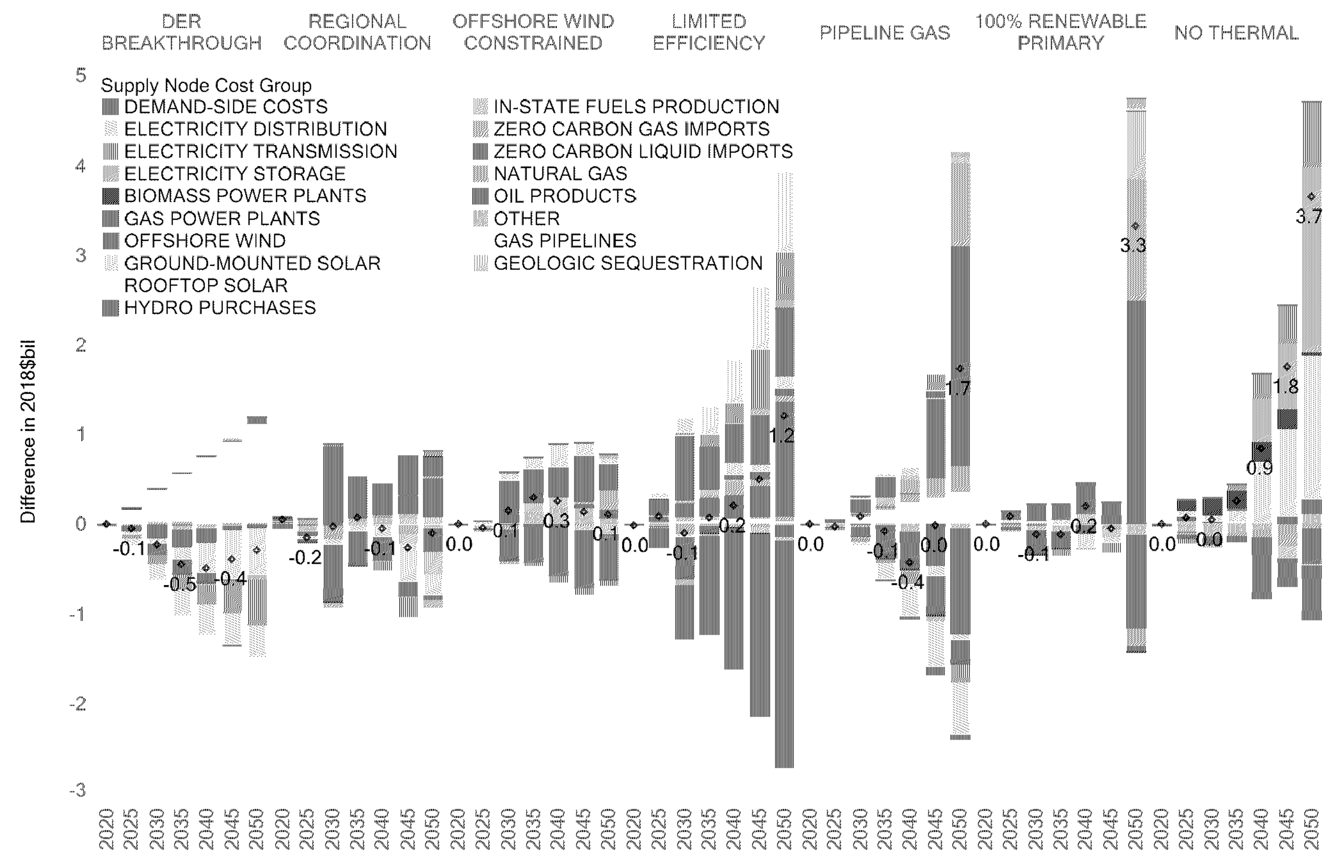


Figure 36. Massachusetts net energy system cost for all net-zero pathways compared to the All Options pathway broken out by cost component. The labeled black circles show the total net cost after summing each component. Pathways are ordered from lowest to highest cost in 2050. For context, three billion dollars is approximately half a percent of the current gross state product.



The second cost cluster in Figure 35 consists of the two pathways with demand-side sensitivities. The Limited Efficiency pathway trades savings on demand-side equipment for higher expenditures on energy, both electricity and fuels. By 2050, the net annual cost is $1.2B per year higher than the All Options case. The Pipeline Gas pathway saves costs associated with electricity generation and delivery, including offshore wind, some transmission, and significant distribution costs. On the other hand, spending on natural gas, gas pipelines, and net-zero carbon fuel imports increased. The demand-side capital cost difference between low and high electrification was estimated to be small. On the one hand, air source heat pumps cost more than gas furnaces, but they also avoid the separate cost of an air conditioner. The cost assumptions for space heating and cooling technologies are discussed further in Section 7.5. The annual net cost in 2050 for the Pipeline Gas pathway is estimated to be $1.7B higher than the All Options pathway. Due to the uncertainty associated with different parts of this cost estimate, low- and high- cost sensitivities were run. The assumptions used to perform the cost sensitivity are presented in

Table 9 and the results in Table 10. In general they highlight that relatively modest changes in the price of carbon neutral fuels could lead to significant (approximately 80%) changes in the net cost of the pathway It should also be noted that incremental costs compound with reduced thermal electrification and efficiency investments because increased demand for zero carbon fuels increases both the total amount of fuel demanded as well as increasing per-unit costs.

Table 9. Assumptions for the Pipeline Gas pathway high and low-cost sensitivities

Category	Base Assumption	Pipeline Gas Low Cost Sensitivity	Pipeline Gas High Cost Sensitivity
Carbon Neutral Liquid Import	$40/MMBtu	$30/MMBtu	$50/MMBtu
Carbon Neutral Gas Import	$30/MMBtu	$20/MMBtu	$40/MMBtu
Gas Distribution Pipeline	2% per year max rate of pipeline retirement	No cost difference because declining volumes lead to no difference is revenue requirement between pathways	4% per year max rate of pipeline retirement
Electricity Distribution Grid Upgrades	$205/kW-year	$250/kW-year	$180/kW-year

Table 10. Pipeline Gas pathway cost sensitivity results. All costs are net costs compared to the All Options pathway. Positive numbers indicate a cost increase and negative numbers indicate cost savings.

Net Cost Category (2018$bil)	Base Assumption	Pipeline Gas Low Cost Sensitivity	Pipeline Gas High Cost Sensitivity
Carbon Neutral Liquid Import	2.45	1.84	3.06
Carbon Neutral Gas Import	0.92	0.62	1.22
Gas Distribution Pipeline	0.37	0.00	0.74
Electricity Distribution Grid	-0.58	-0.75	-0.54
Other	-1.43	-1.43	-1.43
Sum	**1.73**	**0.28**	**3.05**

The third cost cluster in Figure 35 consists of the 100% Renewable and No Thermal pathways. The 100% Renewable pathway costs are very similar to All Options up until 2050, when a dramatic increase in imports of net-zero carbon fuels result in a net cost of $3.3B per year. This pathway is more sensitive than any other to the assumed cost of these fuels, and to the cost of fossil fuels in 2020. If the cost of fossil fuels is higher and the cost of decarbonized drop-in replacements lower, the net cost will be reduced, and vice-versa. The most expensive pathway studied was No Thermal, which had significant cost increases in transmission, solar PV, and battery storage, with only small cost savings from avoided offshore wind and gas power plant capital cost. This pathway is most sensitive to the cost of energy storage.

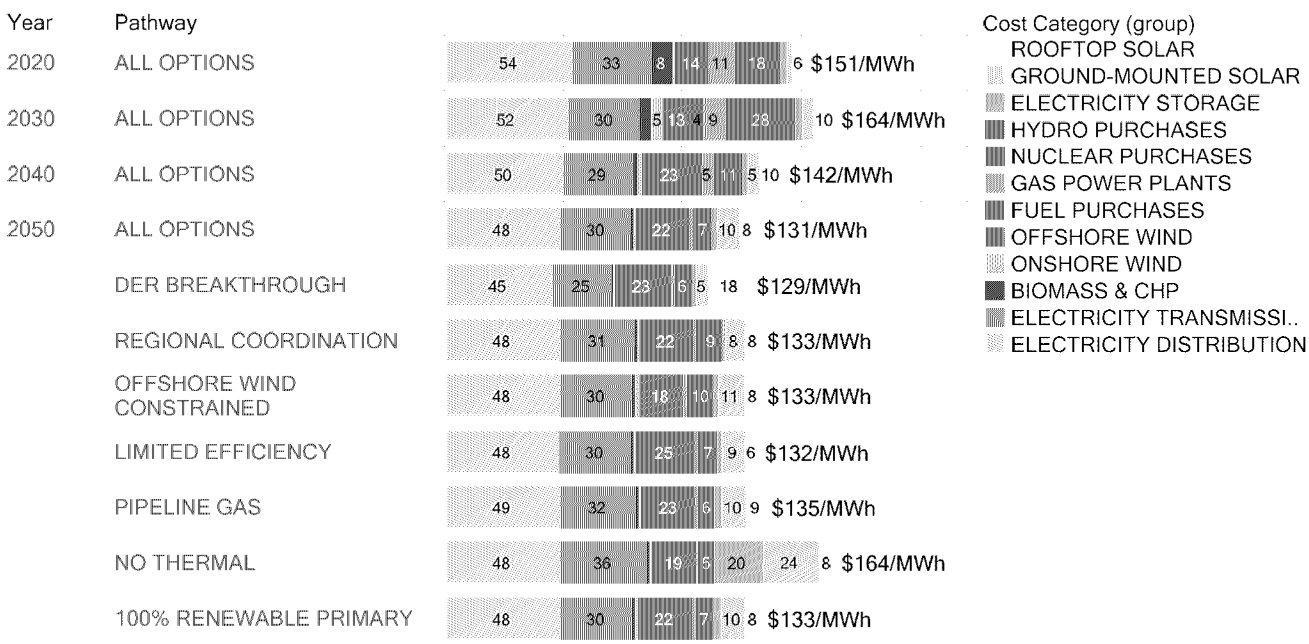
5.6.3 Electricity and gas rates

Dividing the gross energy system cost for electricity and natural gas by total retail sales provides an estimate of average rates for each, which are shown in Figure 37.[47] Rates increase out to 2030, then decrease in the subsequent 20 years. In the near-term, additional imports of hydro from out-of-state increase the cost of electricity relative to generating electricity with gas in Massachusetts. In addition, the first offshore wind builds in the 2020s are reflected in the 2030 rates, with initial installation costs that are higher than those anticipated

[47] These average rates differ from customer retail rates in two ways. First, rooftop solar is included as it is a cost to consumers, but not typically reflected in utility bills. Second, generator profits in energy markets are not included. These profits reflect a cost transfer but not a net cost increase for electricity generation for society.

in the subsequent two decades. After 2030, growth in electricity load, and vehicle electrification in particular, allows for a reduction in the per-unit cost of wires on the system. This happens for two reasons. First, flexible EV charging builds load at night, increasing the load factor in all parts of the system. Second, we assume a correlation of 0.8 between peak load growth and revenue requirement growth. This means doubling the load on a distribution feeder results in an 80% increase in system cost. This assumption stems from the fact that many costs are essentially fixed, regardless of peak load growth, for example the cost of maintenance or tree trimming. Note that while the average cost of wires decrease per unit of retail electricity, the overall revenue requirement is increasing significantly, as shown in the gross costs in Figure 33.

Figure 37. Average societal electricity rate by component, across years and between pathways.[48]



The revenue requirement components, total sales, and implied average societal rates for natural gas are shown in Table 11 for the Pipeline Gas, All Options, and 100% Renewable pathways. The reference case is also included for comparison. The Pipeline Gas pathway sees average gas rates double from $10.7/MMBtu in 2020 to $20.5/MMBtu in 2050, similar to the price paid by retail customers in Europe today. The rate increase came from two sources: (a) the incremental cost of the necessary purchase of net-zero carbon fuels; and (b) the increase in per unit T&D cost, because natural gas volumes decreased 37% relative to 2020 due to a combination of efficiency and partial electrification, while the cost of gas transmission and distribution was assumed to only decrease by 10%. This estimate does not include the cost of carbon allowances, which would be necessary in some policy frameworks due to the fact that pipeline gas was not fully decarbonized, reflecting the high sensitivity around deploying decarbonized gas, as discussed above and in Section 5.1

In the All Options pathway, the implied retail cost of gas more than quadruples from today's rate to $49.1/MMBtu, creating obvious challenges for the remaining customers on the gas system. In the All Options pathway, rapid building electrification is pursued, significantly reducing the volume of pipeline gas sold.

[48] The rates calculated and displayed here are lower than retail rates today for three primary reasons: (1) generator profits in energy markets are not included; (2) additional programmatic costs often included in customer bills are ignored here; and, (3) these rates reflect an average of all customer classes and are not an estimate of residential rates alone.

However, the gas distribution pipeline costs cannot be depreciated as fast as the throughput declines. How this situation turns out in practice depends on the geographic patterns of customers switching to electricity. If customer switching is randomly distributed, no parts of the gas system can be retired easily because of remaining customers who have not switched. On the other hand, if electrification was to proceed one neighborhood at a time with all customers switching at once, it may be possible to start saving gas distribution costs sooner. These questions are discussed further in Section 6.2.1.

Table 11. Pipeline gas sales, revenue requirement, and implied societal rates for 2020 and for selected pathways in 2050.

		REFERENCE 2020	REFERENCE 2050	PIPELINE GAS 2050	ALL OPTIONS 2050	100% RENEWABLE 2050
Massachusetts Sales (TBtu)		255	327	161	34	34
Revenue Requirement ($B)	Net-zero carbon fuels	-	-	0.95	-	1.01
	natural gas	0.63	1.25	0.47	0.13	-
	transmission	0.25	0.31	0.33	0.33	0.32
	distribution	1.85	2.30	1.56	1.19	1.19
	sum	**2.73**	**3.86**	**3.31**	**1.65**	**2.53**
Rates ($/MMBtu)	Net-zero carbon fuels	-	-	5.9	-	30.0
	natural gas	2.5	3.8	2.9	4.0	-
	transmission	1.0	1.0	2.0	9.7	9.6
	distribution	7.3	7.0	9.7	35.5	35.5
	average rate	**10.7**	**11.8**	**20.5**	**49.1**	**75.1**

6 Discussion

6.1 Commonalities across pathways

This study analyzed eight different pathways to attaining a net-zero CO_2 energy and industrial (E&I) system in Massachusetts by the year 2050 while providing the same level of energy services as a high-carbon reference case. The value of the pathways concept, the role of pathways analysis in planning, and the risks of making long-term investment decisions in energy without a pathways analysis, are discussed in Section 2.3. The limitations of pathways analysis are caveated in Section 3.3, which lists some of the known uncertainties in this study. As described in these sections, an important value of conducting the kind of scenario and sensitivity analysis done here is the identification of common elements across pathways. One test for 'robustness' is the appearance of a strategy in different decarbonization pathways that is effective across a wide range of future uncertainties. Among the pathways analyzed here—not an exhaustive set, but one that explored many of the key variables—some clear common themes can be identified, as well as some illuminating contrasts.

6.1.1 **Pillars of energy decarbonization**

The Deep Decarbonization Pathways Project (DDPP) identified[49] three strategies common across all energy systems that transition toward deep emissions reductions—namely, electricity decarbonization, energy efficiency, and electrification (more broadly, fuel switching). This result was found independently by all sixteen country teams involved in the project and has been echoed by multiple studies since that point.

In more recent work[50] exploring U.S. pathways consistent with returning atmospheric CO_2 concentrations to 350-ppm by 2100, an additional pillar emerged, the use of carbon capture. This includes negative emissions and biogenic sequestration. From a mathematical standpoint, negative emissions are a tautological precondition for net-zero emission, as net indicates the sum of both positive and negative emissions. Where the parallel Land-Use Study focused on increasing negative emissions on natural and working lands in Massachusetts, this study focused on the opportunity presented by carbon capture. The use of the captured CO_2 varied, in some scenarios being sequestered, in others being used to synthesize hydrocarbon fuels, but CO_2 was captured in some quantity across all pathways.

This study is in agreement with these past findings in showing that the main strategies for reaching a net-zero E&I system can be organized into four pillars, illustrated for the All Options pathway in Figure 38. Illustrations of the four pillars for the Pipeline Gas and Limited Efficiency pathways are provided in the supplemental materials, Figure 61 and Figure 62 respectively. These additional figures show that even with low building electrification and no adoption of same-fuel efficiency measures, the pillars still hold. In the case of the Pipeline Gas pathway, the electrification of transport still results in a significant increase in the share of final energy delivered by electricity, and in the Limited Efficiency pathway, efficiency inherent in building and transport electrification still results in large reductions in energy use per capita. The following metrics drawn from the All Options pathway provide benchmarks for the four pillars of the transition to a net-zero CO_2 E&I system.

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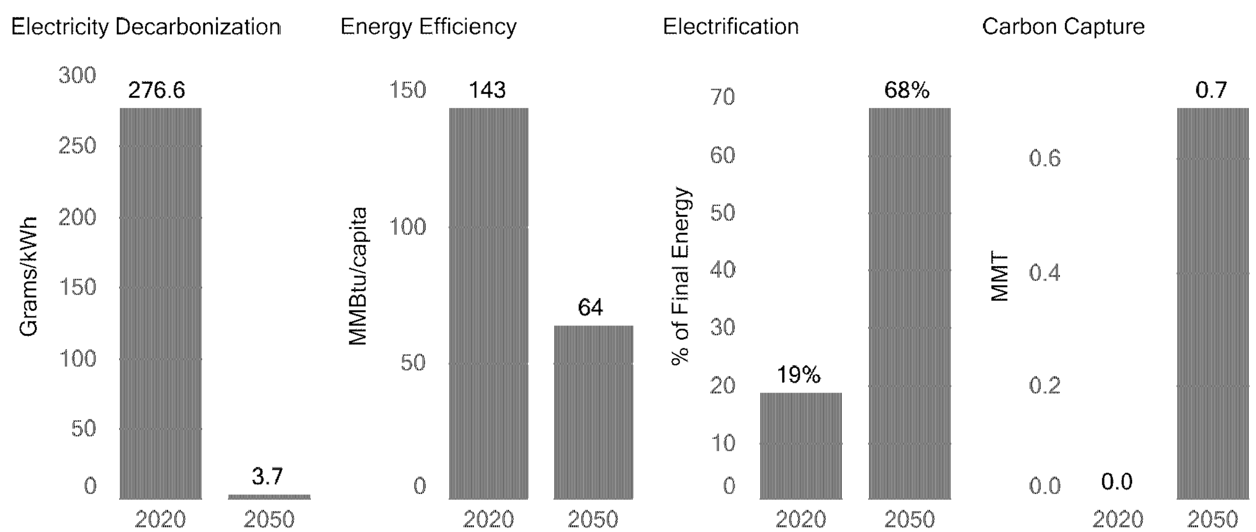
[49] Deep Decarbonization Pathways Project. Pathways to Deep Decarbonization. https://lpdd.org/wp-content/uploads/2020/04/DDPP_2015_REPORT.pdf

[50] Evolved Energy Research, 350 ppm Pathways for the United States, May 2019, https://www.evolved.energy/post/2019/05/08/350-ppm-pathways-for-the-united-states

- **Electricity Decarbonization**: The carbon intensity of electricity production is reduced by 98% (from 277 to 3.7 grams CO_2 per kWh) from 2020 to 2050; this is a nearly complete decarbonization of electricity. Use of carbon-neutral fuels in thermal power plants to achieve 100% decarbonization within the electricity sector would result in only a relatively small cost increase due to the low volume of gas burned, but it is not necessary to do this for meeting the Net Zero target economy-wide.
- **Energy Efficiency**: Per capita final energy consumption is reduced by more than half (from 143 to 64 MMBtu) between 2020 and 2050. Electrification is the single largest factor in this change, as can be seen from comparing final energy demands in Section 5.3.1. Same-fuel efficiency also contributes to the overall efficiency improvement, as illustrated by the effects of its removal in the Limited Efficiency pathway.
- **Electrification**: The share of final energy delivered as electricity is 68%, in 2050 increasing by a factor of 3.5 from 2020 levels. This 2050 electrification share is higher in Massachusetts than elsewhere in the U.S. because of lower industrial fuel consumption in the Commonwealth. While the question was not explicitly addressed in the analysis, it can be inferred from the Pipeline Gas scenario that slow or partial electrification can occur either in buildings or in transport, but not in both, if the net-zero goal is to be attained. This conclusion is predicated on the levels of biomass and hydrocarbon fuels production that are feasible and sustainable at the national level; these in turn imply a limit to the amount of carbon-neutral fuels that can be sustainably imported into Massachusetts, and thus a lower limit to the electrification required.
- **Carbon Capture**: Captured carbon within the Commonwealth reaches 0.7 Mt in 2050. The carbon is captured in industry (specifically, cement and lime production) and biofuel refining. Depending on the pathway, captured carbon is either re-used in a Fischer-Tropsch process to synthesize hydrocarbon fuels, or exported to be sequestered geologically. The carbon capture required outside of Massachusetts to produce net-zero carbon fuels for import into the state was not directly quantified in this study. Thus, even if no capture occurs within Massachusetts state boundaries (a feasible pathway), carbon still needs to be captured in the broader U.S. economy to support the state's energy system.

Figure 38 Four pillars of decarbonization for the All Options pathway. Metrics include a 98%+ reduction in the carbon intensity of electricity production, a 55% reduction in per capita energy consumption, a 3.5x increase in the fraction of final energy delivered from electricity, and captured carbon within Massachusetts of 0.7 Mt. Not shown is captured carbon outside of MA that is associated with synthesizing net-zero carbon fuels for import. The electrification metric excludes asphalt use in construction, which is not combusted.



6.1.2 Common findings on key areas of transformation

In addition to the four pillars that are the foundation of all net-zero pathways, there are other important commonalities. This section compares the results across all eight pathways in seven key areas—offshore wind, new transmission, gas generating capacity, transportation electrification, fuel and electricity coupling, energy storage, and flexible end-use loads—in order to identify the most important common findings and their possible implications for policy.

Offshore wind: Offshore wind is critically important to net-zero carbon energy systems for Massachusetts. A minimum of 15 GW of offshore wind is installed in Massachusetts by 2050 in all pathways, except where constrained by potential caps. Offshore wind resource quality is higher, and the potential greater, in Massachusetts than in many surrounding states (for example, Connecticut, which must interconnect through neighboring states to reach the rich offshore wind areas in the open ocean), highlighting the importance of offshore wind in Massachusetts not only for the Commonwealth's carbon goals but also the regional electricity strategy, potentially providing economic opportunities for wind exports. At some point between 2035 and 2040, the dominant installed technology transitions from fixed to floating wind farms, after most of the potential sites for fixed offshore wind, including large areas not currently identified and available for lease, are built out. If offshore wind deployment is constrained or turns out to be significantly more expensive than anticipated today, the actions required over the next decade will still be substantially the same; the near-term priority is demonstrating the ability to interconnect large amounts of wind generation quickly, safely, and at low cost. If the wind deployment can be achieved and the production variability of offshore wind managed within ISO-NE, and in partnership with neighboring regions, the evolution of the electricity system will look more like that in the All Options pathway. If the wind deployment proves unattainable or can only be achieved at significantly higher cost, electricity imports and/or new nuclear power plants—not necessarily in Massachusetts-- become the necessary fallback strategies. Installation of solar PV is substantial across every pathway; however, because the patterns of production are different for wind and solar, the two forms of renewable energy fill different niches in the power system and are not exact substitutes for one another. This can be observed in the results of the Offshore Wind Constrained pathway, which has no increase in solar deployment within Massachusetts compared to the All Options pathway, despite substantially reduced levels of wind generation. Overall, the fate of offshore wind is the most pressing question for Massachusetts to determine regarding electricity generation during the coming decade, followed by inter-regional transmission.

New transmission: Transmission expansion in the region is of three different types, all of which have been analyzed in this study. The first type is spur lines associated with utility-scale renewables development, which are needed for connecting renewables to load. The second type is reinforcements and upgrades across the entire transmission network, which are needed for managing the load growth from electrification. The third type is transmission between U.S. states, and between the U.S. and Canada, which is needed to facilitate greater regional trade of electricity. As described in Section 5.4.3, transmission plays an important role in balancing generation and load in high renewables power systems. This is doubly true when the storage capabilities of the Quebec hydroelectric system to shift energy in time are considered. Our results show that, if expanded and operated for this purpose, transmission ties between New England and Quebec can be used to mutual advantage, avoiding the need for additional balancing resources to be constructed within New England (new thermal power plants and new energy storage facilities), thereby reducing electricity system cost. Across all pathways a minimum of 2.7 GW and a maximum of 4.8 GW in new transmission capacity directly between Quebec and Massachusetts are built. Additional transmission capacity is also constructed between Quebec and other New England states, and between Quebec and New York, in every pathway modeled. The sum of all new transmission capacity between the northeastern U.S. and Quebec is 13.5 GW in the Regional Coordination pathway and 8.5 GW in the All Options pathway.[51] These findings are significant because these levels of new transmission build emerged from the analysis despite the intentional use of pessimistic assumptions about the cost of new inter-regional transmission, as a way of reflecting the historical challenges of siting new long-distance transmission in the region. As a point of comparison, the New England Clean Energy Connect (NECEC) has a projected cost of $950 million dollars and would run 145 miles with a capacity of 1.2 GW, implying a cost of $5,460 per megawatt mile.[52] This is 42% below the transmission cost of $9,415/MW-mile assumed in all pathways except for Regional Coordination. In the Regional Coordination case only, the cost was assumed to be $4,701/MW-mile, 14% below the NECEC benchmark. New transmission development was found to be of the greatest importance in the No Thermal pathway for which the sum of new inter-regional capacity is more than three times that of the All Options pathway.

Thermal generating capacity: In all scenarios, the use of gas generation decreases through 2050. While 10.8 GW of gas is the minimum size of the regional gas fleet across scenarios, it is used only sparingly in 2050, operating with an aggregate capacity factor of less than 6%. The minimum regional gas fleet size in ISO-NE is 10.8 GW in the Pipeline Gas pathway and 15.4 GW in the All Options pathway. For comparison, as of the end of 2020, there is a total of 16.9 GW of gas capacity (as modeled) in the ISO-NE system. These results must be caveated, in that a single weather-year of data was used in the analysis; this study is not a substitute for reliability planning within the region. Maintaining today's power system reliability while using only renewables and storage results in a minimum incremental cost of $1,000 per household per year, barring order-of-magnitude breakthroughs in the cost of long-duration storage technologies.[53] The need for 'sustained peaking capacity'[54] in the region is explained in Section 5.4.3, which shows the results for renewables balancing; these results indicate that the region must be prepared for a minimum of six consecutive days with no appreciable offshore wind generation. However, despite the critical role gas capacity plays in regional reliability, it is used very sparingly; in 2050 dispatchable thermal operate with an average annual capacity factor of less than 6% across all net-zero pathways. Operation of gas power plants without carbon capture has a high marginal cost in 2050, either because decarbonized fuels with a high $/MMBtu cost are burned, or because natural gas emissions must be offset elsewhere at a high $/tonne carbon abatement cost. For this reason, the number of operating hours needs to be low; if the number of operating hours is high, the more economical solution for reliability is gas generation with carbon capture, or nuclear generation, or imports. The latter two strategies are deployed in the Offshore Wind Constrained pathway. Gas with carbon capture is a poor fit in New England,

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[51] Sustainable Development Solutions Network, Evolved Energy Research, and Hydro-Quebec, Deep Decarbonization in the Northeastern United Stated and Expanded Coordination with Hydro Quebec, April 2018, https://irp-cdn.multiscreensite.com/be6d1d56/files/uploaded/2018.04.05-Northeast-Deep-Decarbonization-Pathways-Study-Final.pdf

[52] New England Clean Energy Connect, Army Corps of Engineers Grant Permit to AVANGRID's New England Clean Connect Clean Energy Corridor, November 2020, https://www.necleanenergyconnect.org/necec-milestones

[53] The size of the long duration storage resources needed to fully replace thermal capacity may be underestimated for two reasons (1) a single weather year was used in the analysis (2) the dispatch model has perfect foresight and can perfectly 'prepare' for the worst event of the year leading up to it by making sure the state of charge is full (see Figure 54). In actual operations, forecasts will never be this good 3-5 days in advance, making a high degree of conservatism necessary in operation and leading to an increase in the storage capacity found here. Since even with optimistic operational assumptions, the costs of the No Thermal pathway were high, this shortcoming was not pursued further. However, any future work that explores the effect of cost breakthroughs in long duration storage should revisit these dynamics.

[54] Distinguished by the fact that it is not duration limited, like a battery. This role is sometimes referred to as 'clean firm.'

where there are few potential sites for geologic sequestration, and the anticipated cost of pipelines to carry CO_2 south into the Appalachian basin is high.[55]

Transportation electrification: As described in Section 6.1.1, electrification is a pillar of all decarbonized energy systems. Electrification of transportation is an essential linchpin of the transition to a net-zero economy, from the physics, cost, and all-sectors perspectives. Transportation electrification is assumed in all pathways to be the primary technological strategy for reducing transportation CO_2 emissions. The latest projections of battery cost indicate that high levels of transportation electrification will be cost effective in all decarbonized energy systems, even assuming low oil prices in the counterfactual case. In addition, given the limited supplies of sustainable biomass for making carbon-neutral fuels, the ability to have lower or slower building electrification, and therefore maintaining higher fuel use in buildings, is predicated on having rapid electrification in transportation. For these reasons, transportation electrification is a no-doubt, no-regrets strategy for the Commonwealth.

Fuels and electricity coupling: The use of electricity to power hydrogen electrolysis and dual-fuel electric boilers[56] was found to have large benefits for the region as complements to a high renewables electricity system. Large loads such as these that can operate flexibly (that is, be utilized more or less as conditions require) on long timescales benefit the E&I system in three ways: (1) they provide a productive use for surplus renewable generation, improving the economics of a high renewable system; (2) they produce useful products (hydrogen and steam) that substitute for fossil fuel combustion in sectors that were difficult to directly electrify, reducing emissions; and, (3) by keeping marginal curtailment low, they allow for the overbuilding of renewable generation, which reduces the gap between renewables and must-serve loads during times of renewables scarcity. This is further described in Section 5.4.3.

Energy storage: Energy storage for shifting bulk flows of renewable energy from the time it is generated to a time it is needed to meet load is of less importance in Massachusetts than in states further south that have greater potential use for solar and less potential use for wind. This is because the time-signature of energy imbalance with solar is much shorter, leading to frequent charge and discharge cycles of limited duration (5-8 hours) with predictable regularity (daily). By contrast, wind production can vary over a timescale of days or weeks, resulting in the need for energy storage of much longer duration and less frequent charge and discharge cycles. In New England, expanded transmission ties with Quebec offer the ability to provide energy balancing across all timescales at lower cost than battery storage. For these reasons, this study did not find energy storage resources to be competitive for bulk energy shifting at any significant level. However, storage was not studied as an alternative to additional investment in distribution infrastructure within Massachusetts. This may hold significant locational benefits, such as resilience and peak cost reductions, and is a topic that requires further research.

Flexible end-use loads: The value of flexible end-use loads such as electric vehicle charging was found to be significant, primarily in limiting or avoiding the need for transmission and distribution system upgrades

[55] Increased sequestration of New England emissions would also compete with captured carbon from PJM, which has higher loads, poorer offshore wind potential, and closer proximity to geologic sequestration sites.
[56] The term dual-fuel electric refers to a boiler that can switch between electricity or pipeline gas in order to make steam. The value of this technology is that adding electric resistance elements to a boiler is relatively inexpensive, and because it has a secondary source for heat, can operate flexibly.

following high levels of electrification in transportation or buildings. Flexible load and battery storage were competitors for diurnal load shifting with an increase in one leading to a reduction of the other. Flexible load's role in the electricity system, like that of battery storage, was found not to have a significant impact on the installed gas generating capacity needed in the region. This is because the role of thermal generation is not primarily in meeting short duration peaks, but in providing bulk energy during long stretches with low renewable production.

6.2 Dynamics of resource competition

This section dives deeper into areas of resource competition for which different outcomes were observed across pathways. The discussion below identifies the key trade-offs and frames the outstanding questions for Massachusetts. The first section explores issues related to building electrification; the next examines distributed versus large-scale solar; and the last centers on the role for decarbonized fuel imports.

6.2.1 **Building electrification versus decarbonized gas**

Conceptually, the approach to building electrification across the U.S. should depend on climate zone, since the main driver of gas use in buildings is space heating, for which both demand and thermal efficiency depend on the weather. This implies that a certain heating degree day threshold exists beyond which, for anything colder, decarbonized gas is the winning strategy. Based on the assumptions made in this study, the pathway results indicate that achieving a high level of building electrification for heating in the Northeast has a lower net cost than decarbonizing gas supplies for that purpose.[57] Both strategies lead to multiple outstanding questions and implementation challenges. The implementation details will be a large factor in determining which strategy is best for the state in practice, since although building electrification appears to be lower cost, decarbonized gas is not cost prohibitive. This cost difference is shown in section 5.6.2, with the annual incremental cost of the Pipeline Gas pathway estimated at $1.7 billion dollars per year in 2050, equivalent to less than 0.3% of gross state product today. As discussed in Section 5, the incremental cost of Pipeline Gas is highly sensitive to input assumptions around the cost and supply of decarbonized gas.

Exactly when a climate is cold enough that decarbonized gas is a better choice depends on many factors, which are summarized in Table 12. Some of the factors are counter-intuitive; for example, that higher vehicle charging flexibility increases the competitiveness of pipeline gas. These dynamics illustrate why the question of building electrification must be evaluated from a whole energy system perspective to obtain a more complete picture.

[57] In both the All Options and Pipeline Gas pathways, distillate heating systems are replaced with heat pumps. Thus, a large degree of building electrification can be said to occur on either pathway. This section discusses the further question of pipeline gas application electrification in buildings.

Table 12 Factors that change the relative competitiveness of decarbonized gas relative and electrification.

Factors	How this can increase *gas* competitiveness	How this can increase *electrification* competitiveness
New construction		Without the complication of exit from the gas system, electrification is more compelling
Existing building stock	Building design may not be conducive to heat pump installations	
Improved building efficiency	More bio-feedstock supplies are available for remaining uses. Customer comfort issues may arise with heat pumps.	Peak heating loads from electrification are decreased and heat pump sizes reduced
Systems with high air conditioner saturation		Heat pumps double as air conditioners, avoiding this cost
Heat pump technology improvements		High COP at low temperatures improves heating load factors
Partial building electrification	More bio-feedstock supplies are available for remaining uses	Throughput on the gas system decreases, increasing rates
Decarbonized fuels available at high volume	A necessary pre-condition for the Pipeline Gas pathway	
Low-cost decarbonized fuels	Directly improves gas affordability	
Older distribution pipeline stock	Financial stock may be depreciated, and customers enjoy low gas rates	Safety or lifetime concerns trigger major upgrades for continued pipeline use, increasing gas rates
Systems with high vehicle electrification	Bio-feedstock supplies are available to decarbonize pipeline gas	T&D upgrades are already triggered by vehicles
Systems with high vehicle charging flexibility	Difference in distribution upgrades needed with or without building electrification increases	*See V2G*
Systems using distributed storage or vehicle to grid (V2G)	Allows for potential operation of furnace fans to provide heating when there is no power	Non-wires alternatives to avoid distribution cost and shave morning needle peaks. Can supply heat pumps during power outages, but not for as long as furnace fans.
Systems with high transmission and distribution upgrade costs	If the marginal cost of increasing peak load on distribution circuits or adding transmission is high, decarbonized gas is more competitive	

From a customer perspective, heating reliability in the Northeast will remain a major issue. In this regard, neither electrification nor decarbonized gas holds a clear advantage with today's technologies, since most heating systems go off during power outages. In the future, either heat pumps or furnace fans could be connected to backup power (for example, dedicated battery storage or EV discharge to the home). In any case, improvements in grid reliability (SAIDI/SAIFI/CAIDI),[58] accompanied by improvements in building shell efficiency that help maintain customer comfort in the event of an outage, are likely to remain priorities in either pathway.

In Section 5.6.3, Table 12 showed gas rates doubling by 2050 due to a combination of reduced throughput (caused by increased energy efficiency and partial electrification) and the higher cost of decarbonized gas[59] relative to natural gas, while average electricity rates stay more or less constant. This represents a major risk associated with the Pipeline Gas pathway because if heat pumps become competitive for the end consumer, an uncontrolled exit from the gas system could occur. Such a scenario would lead to a further escalation in gas rates in which fixed costs are paid by fewer and fewer remaining customers. This also raises significant equity concerns, in that customers who are less able to adopt new technologies that have higher up-front cost (e.g. heat pumps) could end up paying much more for their energy on the legacy gas system. Implementing a controlled exit from the gas system also presents risks and challenges. Exactly how the exit from the gas delivery infrastructure can be carried out in an organized and fair fashion is a question for policy makers and gas utilities.

One observation about the prospects for building electrification is that in most cases, the forms of energy used in space heating, water heating, and cooking are closely linked. What is done in heating, currently the dominant use of natural gas in buildings, will almost certainly decide the issue. Put differently, if heating loads are electrified, the remaining gas applications will not have high enough throughput to support the existing gas delivery system, and these applications will either be electrified, in turn, or move to on-site gas tanks (similar to the use of propane in some applications today).

The crux of the issue for residential building electrification cost hinges on two questions: (1) how much does peak load grow after building electrification, and what costs are induced by this?; and (2) how much do decarbonized fuels cost, and will they be available in sufficient volume? On the first question, differences in seemingly inconsequential modeling assumptions can lead to very different policy conclusions. For example, what is the heat pump coefficient of performance at low temperatures? How will heat pumps improve in the future? Will there be reductions in installation cost for geothermal heat pumps? Are heat pumps assumed to have electric resistance backup?[60] How large are the installed heat pumps? How will building shells improve in the future? Which (and how many) weather years were analyzed? What is the temperature and wind-speed diversity throughout the region? And, does this diversity matter when investigating hyper-local questions on a single distribution circuit?

[58] Common customer reliability metrics: SAIFI measures how often a customer can expect to experience an outage, SAIDI measures average outage duration per customer, and CAIDI measures average outage duration if an outage is experienced.
[59] For reasons also noted, these gas rates are likely low because it assumes gas customers pay nothing additional on the carbon emissions from burning natural gas. If this cost of carbon is embedded in the rate or the fraction of decarbonized gas increased in pipelines, rates would increase by a further 5-10/MMBtu.
[60] A commonly assumed technology configuration for heat pumps says that electric resistance is used as backup and below some temperature threshold, the system switches to resistance elements whereby peak loads spike. Some newer heat-pump configurations forgo the electric resistance backup all together and remain highly efficient at temperatures well below zero degrees Fahrenheit.

On the question of cost and quantity of biomass supplies available to make decarbonized fuels, analyses abound that examine a small handful of subsectors, applying national biomass supply curves to a single city or state, without consideration of the complexity of competing uses for this limited supply. For example, organic bulk chemical and plastics synthesis that requires a hydrocarbon molecule is expected to demand four quads of energy in 2050, potentially accounting for a large portion of available biomass, as discussed in Section 5.5.2. Similarly, applications like long-distance aviation require a volumetric and gravimetric fuel density that, thus far, has only been possible using hydrocarbons. Continued progress in direct air capture and renewables cost may lead to new pathways for producing synthetic decarbonized gas, but major breakthroughs will be needed before these fuels become cost competitive in space-heating applications.

With the remaining uncertainties surrounding building electrification for the region, the following list of actions could be taken to help clarify a path forward:

- **Building load research data**: New England already has significant heat pump adoption, driven thus far by fuel switching away from distillate. Collecting temporal data on the performance of these heat pumps for use in model benchmarking and extrapolation will help to answer remaining questions about what to anticipate regarding the duration and timing of heating peaks. Also, studies could be conducted in partnership with Hydro Quebec, which already has high electric heating penetrations today, to understand the impacts empirically.
- **Pilots to explore decarbonized fuel use**: Further commercial development of the carbon-neutral fuels industry in the U.S. will help to provide empirical data to support modeling assumptions and policy arguments about cost and biomass supplies. For biomethane this also includes further research on feedstock availability and emissions profile to ensure lifecycle net-zero emissions, risk of emissions from land-use change, and other externalities.
- **Detailed, site-specific studies of gas and electric distribution systems**: The cost savings and increases that may follow high building electrification are fundamentally a function of what engineering solutions are required at a local level. This study, and others like it, have provided high level estimates using system-wide factors, but more granular studies can help shape policy and implementation.
- **Full awareness of decarbonization strategies in other sectors:** As seen in Table 13, questions of building electrification interact in complex ways with strategies in other sectors that are undergoing similar transformations in order to achieve the economy-wide net-zero CO_2 target. Adopting the no regrets strategies identified in Section 6.1.2 will help narrow the uncertainty on remaining items.

6.2.2 Rooftop solar versus ground-mounted solar

Aggressive development of rooftop solar can replace the need for some ground-mounted solar, but at a higher cost. The overall generation potential from rooftop solar is modest (<20%) relative to what Massachusetts load will be after significant electrification, even when covering every roof in the state. Both the All Options and DER Breakthrough pathways studied levels of solar (both rooftop and ground mounted) that greatly exceed what is installed today. The All Options pathway assumed 7 GW of rooftop solar was installed in 2050, versus 16.9 GW assumed in the DER Breakthrough pathway; for comparison, today's penetration is a little less than 2.5 GW. The total technical potential identified by NREL is 22.5 GW,[61] implying 1-in-3 roofs, and 3-in-4 roofs, have solar PV mounted on them in the two pathways, respectively.

[61] National Renewable Energy Laboratory, Rooftop Solar Photovoltaic Technical Potential in the United States: a Detailed Assessment, January 2016, https://www.nrel.gov/docs/fy16osti/65298.pdf

A key finding of this study is that rooftop and ground-mounted solar trade off against each other but are largely insensitive to other assumptions except for thermal power plant retirements as in the No Thermal pathway.[62] The modeling suggests that solar PV energy penetration of 25%-30% is optimal from a system balancing perspective. Below this range, additional solar can be deployed to avoid higher-cost generation, and above this range, marginal curtailment or costs required to shift the solar output in time (for example, with storage) increase to the point that solar is no longer cost competitive against other options. From a bulk power system balancing perspective, rooftop solar and large ground-mounted solar play the same role and fill the same electricity generation niche.

This study did not undertake a cost benefit analysis of rooftop solar versus large ground-mounted solar that considered the locational benefits of each, other than for avoided T&D losses from distributed PV. Prior research and direct utility experience have shown that distributed PV can either have costs or benefits, depending on location and the amount of solar installed relative to loads. In many cases, costs increase because high solar penetrations of distribution feeders disrupt existing protection schemes and increase voltage levels outside of ANSI limits, since at the time they were built two-way power-flow over distribution feeders was never anticipated. A subset of potential issues is shown in

Figure 41. On the other hand, strategically placed solar has been shown to improve sagging voltage, and with the use of smart inverters could improve power quality; both of these can help avoid the need for utility equipment upgrades. Implicit in the choice to not consider these factors in this long-term decarbonization study is the fact that distribution system upgrades driven by high electrification loads could subsume most of the costs associated with deployment of distributed PV; adding additional upgrade costs in the modeling could be double counting. This question should be explicitly studied, using the magnitudes of solar identified in these pathways, which are consistent with the Commonwealth's long-term decarbonization goals.

One of the main benefits of pursuing more aggressive development of rooftop solar is limiting the land requirements of ground-mounted solar, as discussed in Section 6.3.1. This land use impact (2.5% of total Massachusetts land are in the All Options pathway), is reduced by half in the DER Breakthrough pathway. This could potentially lead to large ancillary benefits that were not explicitly quantified in this report (i.e., the value of natural and working lands preserved for recreation, agriculture, and increasing the land carbon sink).

Differences in resource quality also make policies pursued in other states, such as net-zero buildings, a more difficult prospect in the Northeast, where ~50% more roof area is required than in the Southwest to produce the same amount of energy. Thus, different types of policies may be needed to encourage solar development. In terms of developing a strategy in Massachusetts over the next ten years, however, this study finds that both rooftop solar and ground-mounted solar are needed and should be actively pursued. Both types of solar installations will be needed in quantities far above what exists today to meet decarbonization goals.

6.2.3 **Fossil fuels vs. net-zero carbon fuels**

The question of fossil fuels versus decarbonized drop-in fuels are simpler in Massachusetts than elsewhere in the U.S. by virtue of the state having limited biomass supplies, and no geologic sequestration potential in the

[62] This is discussed in Section 6.3.1 and is because the regularity of solar vs. wind can help avoid additional energy storage build in replacing the reliability function served by thermal power plants.

immediate region. Instead, the ongoing use of fossil fuels and net-zero carbon fuels in Massachusetts is governed by only two factors: CO_2 reduction targets and progress on electrification.

This study assumed costs for imported decarbonized drop-in fuels that matched recent work in the region ($30/MMBtu for gas, $40/MMBtu for liquid fuels), and that are consistent with having multiple competing uses for these fuels in a 2050 decarbonized energy system.[63] Due to the high costs assumed of decarbonized drop-in fuels relative to fossil fuels, these were only used as a 'last resort' in the economic optimization when necessary to reach the carbon goals. The result was pressure to decarbonize electricity more rapidly in the near-term, and no use of decarbonized fuels (aside from ongoing ethanol imports) until after 2040 in all pathways. However, the transition path for fuels may be more nuanced and challenging than directly suggested in the results.

One important factor is that if U.S. experience in, and markets for, net-zero carbon fuels do not develop until the 2040s, both technological progress and insights into unresolved questions (for example, how much fuel will be available for import into the Northeast) will be delayed. The second consideration is that near-term costs for decarbonized drop-in fuels would be expected to be below the values used in this study, since each fuel has its own supply-curve and near-term competition would be less fierce than assumed in 2050 with a net-zero carbon energy system nationwide. This presents opportunities in Massachusetts to 'learn by doing' in the near-term with few risks, and this can also help shape future electrification policy. In addition, strategic investment in relevant pilots in the buildings and transportation sectors can help both the Commonwealth and private markets identify lower cost decarbonization strategies, as well as increase the pace of market transition. If electrification of transport does not materialize over the next ten years in the ways imagined in all eight decarbonization pathways studied here, net-zero carbon fuel imports in the 2030s will be necessary for following a straight-line emissions path to the 2050 goal.

The 100% Renewable Primary pathway had the highest use of decarbonized fuel imports but otherwise was remarkably similar to the All Options pathway until 2045. The quantity of imported fuels required suggests the best way to prepare for this option will be to focus in the near- and medium- term on high electrification. Beyond this, the fork in the road for reaching the 100% Renewable Primary energy pathway will not arrive for several decades.

Across all pathways, import of net-zero carbon fuels were used first for liquid fuels (versus gaseous fuels) because the avoided cost of refined fossil fuels is far higher than that of natural gas ($15-20/MMbtu vs. $3-5/MMbtu). For this reason, the Pipeline Gas pathway reached the 2050 emissions target by first decarbonizing all other liquid fuels before decarbonizing the pipeline, and then only to the degree required (see energy Sankey diagrams in Figure 7). This approach had the lowest societal cost but resulted in cost increases outside of the buildings sector.

Across all pathways, electrolytic hydrogen was an important complement to electricity balancing and a key decarbonized energy carrier for shipping and industry. The lowest amounts of electrolysis were built when either transmission was cheap or offshore wind was constrained (Figure 60), the former reducing its competitiveness for balancing and the latter reducing the number of hours with surplus electricity. The highest

[63] The Brattle Group similarly assumed $30/MMBtu for gas in a 2020 study on building electrification in Rhode Island: The Brattle Group, Heating Sector Transformation in Rhode Island, http://www.energy.ri.gov/documents/HST/RI%20HST%20Final%20Pathways%20Report%204-22-20.pdf

amounts of electrolysis were built in the Pipeline Gas pathway in which blending of hydrogen into the pipeline (up to 7% by energy) was used as a lower cost alternative to decarbonized methane. Also seen in both the Pipeline Gas and 100% Renewable Primary was the use of hythane[64] in gas power plants, with a much higher blend percentage of hydrogen (50%+). Retrofits for existing power plants to allow this blending is expected to be far cheaper than adding carbon capture, and it allows thermal power plants to act as de-facto long-duration energy storage when electrolytic hydrogen is stored on site for use as a zero-carbon fuel during stretches with low offshore wind production.

Biomass within Massachusetts was assumed to play a limited role across all pathways due to limited biomass supplies in the state, as estimated in the 2016 Billion Ton Report from DOE.[65] Some existing biomass supplies were diverted away from power plants and industrial co-generation towards biofuel generation within the RIO optimization because electricity production had readily available and affordable alternatives, while decarbonized fuels had high marginal cost. The suitability of these feedstocks for this application was not explored and is a topic for further study.

6.3 Renewable build

6.3.1 **Land**

We estimate land use for ground-mounted solar in Figure 39, assuming an average of 4.06 acres/MW_{AC} with a high and low-and estimate developed assuming 7.8 acres/MW_{AC} and 2.9 acres / MW_{AC} respectively.[66] This does not include the land requirements of any new transmission development needed to connect generation with load. The wide range of land use factors used acknowledge the inherent uncertainty associated with project design and technology progression. Many national estimates for solar land use factors are on the high end of the range presented here;[67] however, the high cost of land in Massachusetts compared to the rest of the United States, among other factors, has tended to result in denser development within the Commonwealth. For example, a project currently in development in Sandwich, MA sites 4.5 MW_{DC} on 11 acres of land, implying

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[64] Hythane refers to a mix of hydrogen and methane.

[65] U.S. Office of Energy Efficiency & Renewable Energy, 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, July 2016, https://www.energy.gov/eere/bioenergy/2016-billion-ton-report

[66] The land area required for ground-mounted solar can be decomposed into several factors shown in the equation below:

$$Land\ Area_{AC} = Panel\ Area_{DC} \times ILR \times (1 + ALF) \div GCR$$

Where:

- *Panel Area*$_{DC}$ is the direct panel dimensions per rated megawatt. We assume 1.2 acres/MW_{DC} based on a 20.5% efficient panel from the NREL System Advisor Model. This parameter is expected to decrease over time as efficiency continues to improve.
- *ILR* is the inverter loading ratio (DC system size / AC interconnection size), assumed to be 1.3 in this work.
- *ALF* is the auxiliary land area used by a project for buffers, shading setbacks, roads, and other equipment. We assume a factor of 30% is typical with a high-end estimate of 50%. Smaller projects typically have a larger ALF.
- *GCR* is the ground coverage ratio, which is a measure of the density of the installed panels. The highest density projects are assumed to have a GCR of 0.7 (Turner, 2020) and the lowest density projects a GCR of 0.3. A typical project GCR for Massachusetts is assumed to be 0.5

Based on the above parameters, a set of high, low, and medium land-use factors are calculated:
Low Land Area Estimate = 2.9 acres / MW_{AC} = 1.2 x 1.3 x 1.3 ÷ 0.7
Medium Land Area Estimate = 4.06 acres / MW_{AC} = 1.2 x 1.3 x 1.3 ÷ 0.5
High Land Area Estimate = 7.8 acres / MW_{AC} = 1.2 x 1.3 x 1.5 ÷ 0.3

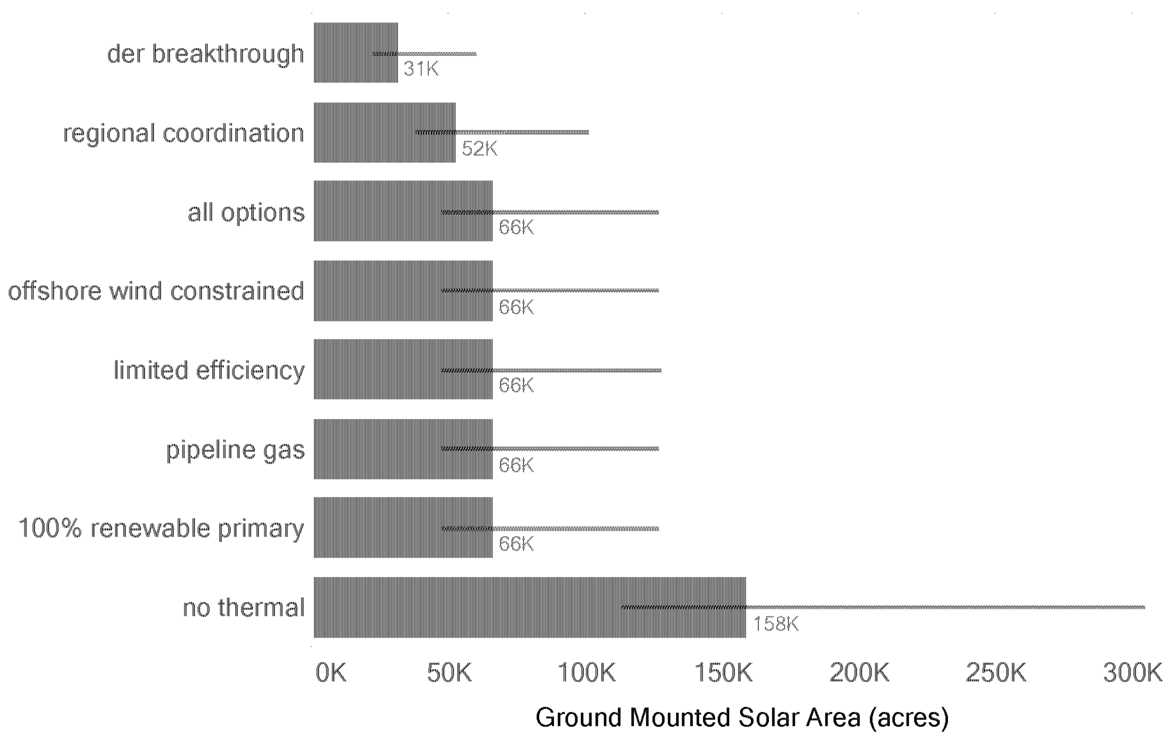
[67] S. Ong, et al. Land-use requirements for solar power plants in the United States. No. NREL/TP-6A20-56290. National Renewable Energy Lab. (NREL), Golden, CO (United States), 2013

3.2 acres per MW_{AC} (assuming an inverter loading ratio of 1.3).[68] Having greater regional coordination, as in the Regional Coordination pathway, reduces land requirements within Massachusetts by about 20%, though it increases land requirements elsewhere. A policy emphasis on rooftop solar development, as in the DER Breakthrough pathway, can cut the land requirement for solar in half.

The solar land-use requirement for the No Thermal pathway is 158,000 acres, just over 3% of Massachusetts' total land area and more than double that of any other pathway. As described elsewhere, the preference for solar over wind in this pathway is because solar has less day-to-day variability and fewer days like February 16th, a model sample day in which offshore wind production drops to near zero over 24 hours+ (see section 5.4.3). The basic dynamic at work is that adding more solar is cheaper than adding additional hours of discharge duration to energy storage, and therefor by flooding the system with solar, more energy can be produced in February 16th and some of the storage avoided. The downside to this strategy, in addition to the high land requirement, is a surplus of unusable energy at other times of the year, with 20% of Massachusetts renewables curtailed in the No Thermal pathway versus 3.2% in the All Options pathway.

Regardless of which pathway the state pursues, these results indicate that land-use for renewables and transmission development will be a major challenge in planning. Geospatially explicit, proactive planning processes that combine energy and land-use, as are starting to be adopted in some states, may provide useful perspectives on addressing this challenge.[69]

Figure 39 Ground-mounted solar PV land-use estimates across pathways. Error bars show high and low land-use estimates based on project design and technology progression. Fifty thousand acres represents approximately 1% of Commonwealth land area.



[68] Turner, J.E., Memorandum: Solar PV Project Design in a Space-Limited Context. Aries Power Systems, LLC, Westborough, MA (United States), 2020.
[69] Wu, G., et al. (2020). Low-impact land use pathways to deep decarbonization of electricity. *Environmental Research Letters*.

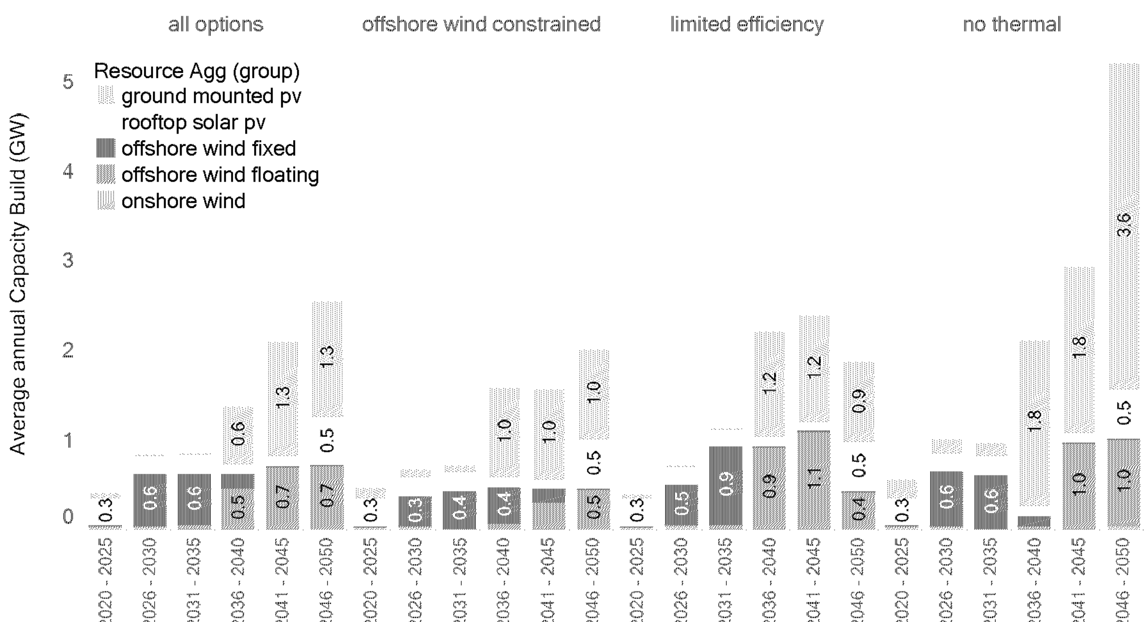
6.3.2 **Build rates**

Separate from land-use, reaching the renewable penetrations described in Section 5.4.2 will require sustained annual builds of renewables far in excess of the rates seen historically. Figure 40 shows the annual average renewable capacity build rates for four different pathways in each five-year period between 2020 and 2050. Modeling can determine the build rates necessary to meet the generation targets in different pathways, but it cannot make normative judgements about whether these build rates can be achieved and sustained.

Offshore wind, the largest source of carbon-free generation in the state, requires annual average build rates of 400 MW per year in the Offshore Wind Constrained pathway and 1,000 MW per year in the Limited Efficiency pathway. The All Options pathway splits this difference with approximately 650 MW built each year on average between 2026 and 2050. This refers only to the build occurring in Massachusetts' waters; a much larger regional wind industry is implied in the pathways. One easily observable benefit from the aggressive adoption of energy efficiency for the state is the ability to slow the pace of this development. If the achievable rate of offshore wind build for Massachusetts is lower than the 650 MW per year in the All Options pathway, it implies an overall state strategy that is more in-line with the Offshore Wind Constrained pathway, with electricity imports playing a more important role. Low annual build rates for offshore wind also make it more likely that new nuclear will be both economic and necessary in the region. Much depends on the ability for transmission expansion as well as the eventual cost and safety concerns for next-generation nuclear.

Annual solar build rates are also substantial, especially for ground-mounted solar after 2035. Within the economic optimization framework of our modeling, the rapid cost declines projected for solar within NREL's 2019 Annual Technology Baseline (ATB) later in the study period results in delayed deployment. However, frontloading some of this solar build could be a good strategy for the state, as a way to develop the industry, develop the ability to site these resources, and reduce pressure on imports in the near-term. The build rates for solar in the No Thermal case, reaching as high as 3.6 GW per year in the 2040s, will be especially difficult to achieve and imply both societal and technological breakthroughs.

Figure 40 Average annual build rate by 5-year period for selected pathways. Taking the example of offshore wind in the All Options pathway during 2026-2030, the annual average build rate of 0.6 GW results in a total of 3 GW built during the five-year period.



6.4 Electricity balancing

In the pathways studied, nearly all electricity not supplied by nuclear generation or imports comes from non-dispatchable, variable renewable generation. Gas generation plays a critical reliability role in such a system, but its contribution to total annual energy production is small. These changes represent a fundamental shift in the planning and operation of power systems, and the implications warrant further discussion.

One important conclusion is that the procurement of capacity (MW) and energy (MWh) are fundamentally separate in decarbonized energy systems. The most resource-constrained days (for example, see the February 16th hourly profile in Figure 28) look nothing like the average day (see Figure 25). The average day indicates the requirements for renewable procurement and meeting the carbon emissions target, which are primarily about energy. The resource-constrained day, on the other hand, indicates the requirements for storage, transmission, and thermal power plants, which are primarily about capacity.

For evaluating the operational impacts of high variable generation on the electricity system, it is instructive to consider the temporal and spatial dimensions of different aspects of the balancing problem shown in

Figure 41. The solution to any one of the challenges shown must be specific to its location on the system (described in terms of voltage level) and the timescale over which the challenge manifests. Thought about in this way, it is clear that there are no silver bullet solutions that address all the challenges raised by variable generation; instead, what is required is a collection of different measures that work in concert. A subset of these, including thermal generation, storage, flexible load, transmission, and curtailment, are shown in Figure 27.

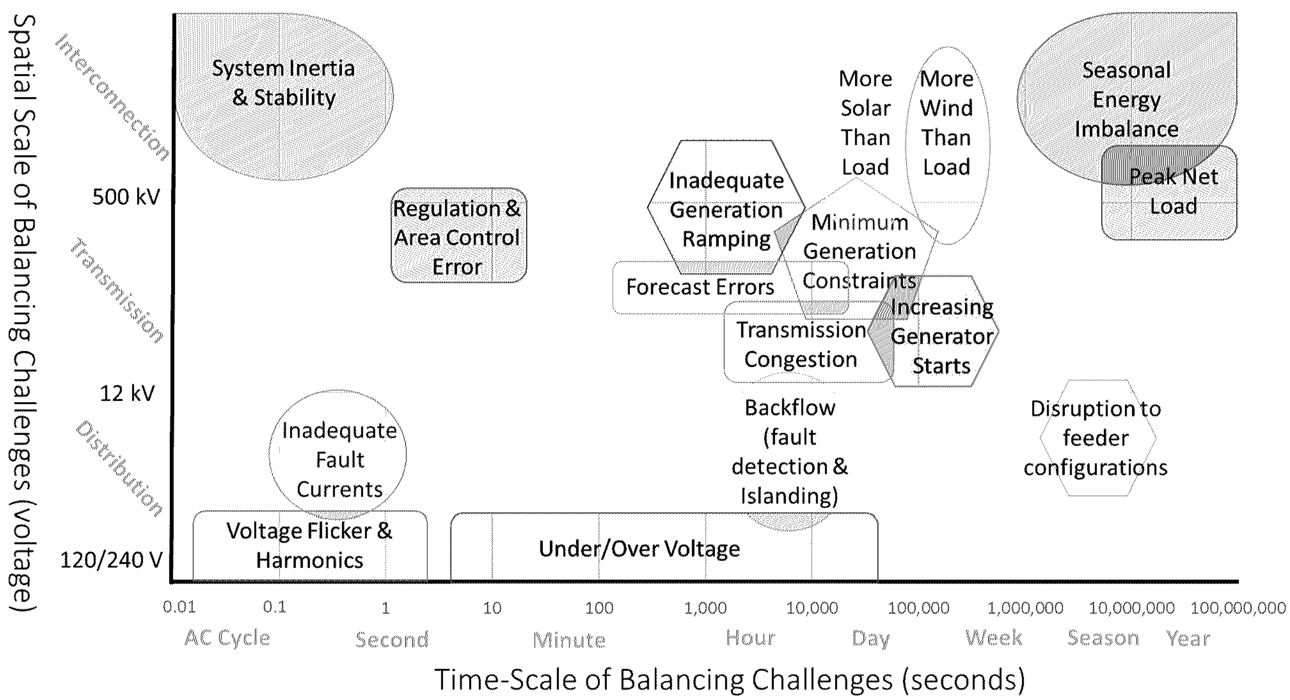
This study has not addressed balancing challenges that occur either at the sub-hourly time scale or on geographic scales smaller than New England states. As noted elsewhere, local electricity storage could play an important role in addressing both sub-state and sub-hourly balancing challenges. Pathways such as the DER Breakthrough, with a high rooftop PV build, may create challenges for distribution systems. Some of these challenges could be addressed through flexible load operation, and others could be addressed by the same upgrades that will already be required to meet new electrification loads, but these aspects were not explored in this report.

The Northeast region presents a unique set of challenges and opportunities when it comes to renewable balancing. The region has large offshore wind potential that is anticipated to have a low levelized cost of energy, but simulated wind datasets show that offshore wind can drop to near zero in any month and remain at low levels of output for long stretches.[70] Across all pathways, the challenges posed by wind variability are made manageable, in part through gas generation and in part through operational coordination with Hydro Quebec, which has over 100 TWh of energy stored behind dams in Quebec, and the ability to shift energy on a seasonal time scale. This study's results are in full agreement with previous studies that highlight the mutual benefits of transborder electricity trade. However, operational coordination involves more than the single issue of trade with Quebec; it also encompasses greater coordination with New York, and between different ISO-NE regions. For example, this study's results show clear patterns of resource specialization within ISO-NE—Massachusetts building offshore wind while Vermont and New Hampshire build solar, with mutually beneficial

[70] The NREL wind toolkit shows offshore wind in Massachusetts dropping below 5% for six consecutive days in August 2012.

trade among them taking advantage of resource diversity. This dynamic among others represents a new operational paradigm in the region, and with it come challenges that go beyond a mere tabulating of the transmission and generating technologies that must be built. The next section discusses electricity markets, just one of the institutional barriers that ahead on the path to Net Zero.

Figure 41. The challenges that can arise in balancing high variable generation (wind & solar) systems are numerous. Most have been extensively studied, with technical solutions existing for each. However, the associated costs are uncertain and no power systems the size of ISO-NE have yet achieved renewable penetrations that match those envisioned in this study. Figure credit: Evolved Energy Research



6.5 Electricity markets

The rapid decarbonization of the New England electricity system envisaged in this report points to the need for major changes in ISO-NE electricity markets, quite distinct from whatever changes are required in engineering and operating procedures to support a high renewables electricity system. We described the basic issues in previous work,[71] which is summarized here in abridged form. The need for changes in electricity markets stems from the fact that electricity markets were originally designed under a paradigm in which most generators were assumed to be dispatchable and to have a non-zero marginal cost, and in which load was passive and far more difficult and costly to control than supply. These assumptions are almost entirely flipped on their heads in a high renewables system, giving rise to a new market paradigm in which almost all costs are fixed, supply itself is variable, and new technology enables demand-side flexibility.

The first key market challenge is how to keep the necessary level of thermal generators in the system. This report highlights the role of thermal generation in a future ISO-NE system with high penetrations of wind and solar (discussed in Sections 5.4.3 and 6.1.2). Thermal generating plants are needed for reliability in a lowest-

[71] Jones, et al. 2019, IEEE Power & Energy Magazine, Electrification and the Future of Electricity Markets, https://www.evolved.energy/post/2018/07/18/future-of-electricity-markets

cost electricity system; however, from an operating hours standpoint, the role of dispatchable thermal gradually but fundamentally shifts from that of "load follower" to "peaker" over the coming decades. Table 13 illustrates this transition using average combined cycle gas plant capacity factors across ISO-NE for each decarbonization pathway. With fewer operational hours, more revenues will likely need to be collected in capacity payments, and for this to work, ISO-NE capacity markets must eventually distinguish between a 6-hour energy storage resource and a gas plant, both of which provide capacity value to the system, but are not substitutable. While technological advancement in longer-term storage options could obviate the need to maintain thermal capacity, this outcome is uncertain; thus failure to maintain thermal capacity represents a significant risk to the regional energy system.

Table 13 ISO-NE gas combined cycle gas turbine capacity factors by pathway

pathway	2020	2030	2040	2050
all options	54.0%	17.1%	14.0%	5.4%
100% renewable primary	54.0%	18.1%	14.4%	3.6%
der breakthrough	54.0%	18.6%	15.3%	5.3%
limited efficiency	53.9%	11.3%	9.8%	4.9%
no thermal	53.8%	18.3%	8.6%	N/A
offshore wind constrained	54.0%	17.9%	15.2%	4.2%
pipeline gas	53.9%	17.3%	6.6%	2.2%
regional coordination	54.0%	17.5%	12.9%	6.2%

The second key market challenge is how to provide the necessary incentives for the participation of flexible loads. The findings of this study highlight the value of flexible loads in operating a highly renewable and highly electrified energy system at low cost. Important flexible loads include both small distributed end-uses (for example: water heating, heat pumps, and electric vehicles) and large industrial loads that are not must-serve (for example: electrolysis). Enabling flexible load to play the role they do in this study will require market symmetry, meaning equivalent treatment of supply-side and demand-side resources. Over time, the current focus of wholesale markets on buying and selling energy needs to evolve toward the buying and selling of balancing services, in which scheduling a load reduction is equivalent in value to committing a power plant. Markets must come to incorporate the concept of resource state of charge, both for energy storage and flexible loads, with resource scheduling optimized accordingly. Finally, markets must send signals to flexible end-use loads regarding when circuit level loads must be decreased in order to avoid the need for new distribution system investments.

6.6 Outstanding research questions

In this report, a number of areas have been identified as being open questions or involving uncertainties that were not explicitly explored in the eight net-zero pathways. The follow-up work identified by this study can be divided into three basic categories: (1) outstanding questions that can be explored further using modeling methods similar to those presented here; (2) outstanding questions that require additional modeling but for which different tools are required; and, (3) questions for which a real-world 'learning-by-doing' approach will be necessary in order to gain better empirical data and on-the-ground insights before important decisions are made. Some of the most difficult questions facing the state (for example, building electrification), have elements that fall into all three categories.

For research questions in the first category, new sensitivities could be developed, for example testing the consequences of slow adoption of transportation electrification, or of breakthroughs in long-duration storage. Also, refinements can be made within existing models to better reflect regional preferences or highlight decisions that impact Massachusetts. Sensitivities involving multiple weather years, different heating electrification technology assumptions, and different costs for net-zero carbon fuels could each help to illuminate the topics raised in the discussion.

For research questions in the second category, there is a critical need for new tools that can assess cost increases or savings within electricity and gas distribution infrastructure from either major increases or major declines in the volume of energy flows. Forecasting exactly how circuit loads on a local level would change is not possible, but 'what if' analyses can be performed that clarify these critical questions for the region.

In the last category, questions include the ability for Massachusetts to build the amount of offshore wind capacity assumed in each of the eight pathways, including the required transmission. Operational experience in high variable generation systems must be learned by doing, with the full toolbox resources at the disposal of system operators to ensure regional reliability.

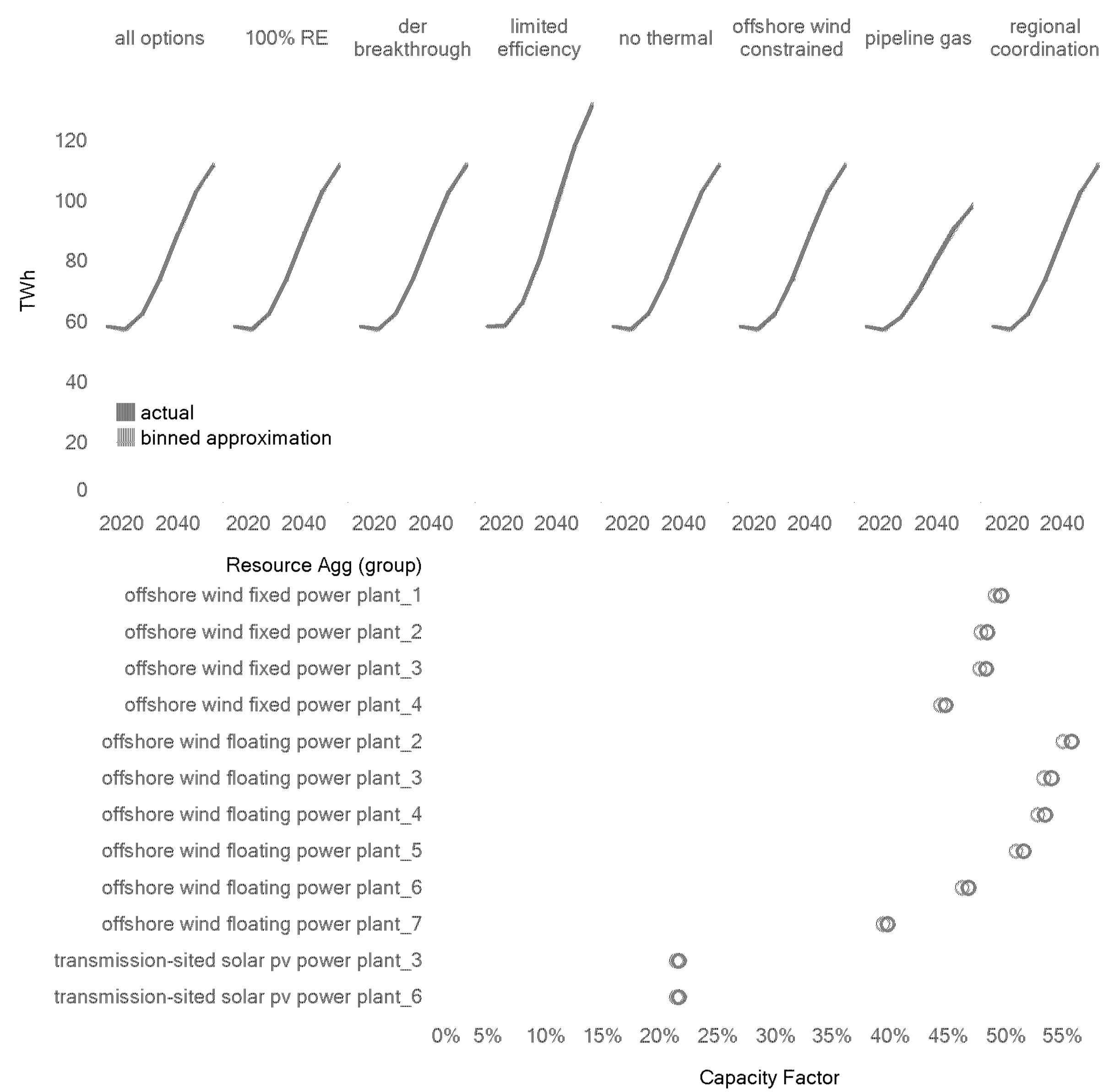
Throughout this report, the results demonstrate both the interconnectedness of decarbonization activities across the Northeast region, and the importance of interactions between sectors within the energy economy with respect to achieving the net-zero goal in Massachusetts. This highlights the need for any future research to consider these factors—not just in quantifying effect magnitudes, but in obtaining directionally correct information for the region.

7 Appendix 1: Data inputs and assumptions

7.1 Weather year & RIO day sampling

This study used a 2012 weather year for loads and renewable profiles. The weather year was chosen to match parallel work for the Building Sector report. A 2011 weather year was also tested but did not change any of the major findings and is therefore not emphasized in the results. The RIO model works by sampling representative days for use in the capacity expansion model. The theory behind and methodology for this day sampling is presented in Section 9.2.3. This study used forty-five sample days. Figure 42 displays the day sampling statistics for Massachusetts and shows a close match between the sampled and actual values for annual load and renewable capacity factors.

Figure 42 Day binning fit statistics for Massachusetts. Each of the 45 sampled days are mapped back to the 366 days in 2012 to approximate a whole year of operations. The binned approximation based on this mapping is shown in orange and the true data for the 2012 weather year is shown in blue.



7.2 Imported net-zero carbon fuels

All pathways were allowed an unconstrained supply of imported fuels assumed to be carbon neutral. Caveats regarding the carbon impacts and import limitations of biofuels are presented in Section 5.5 and 6.2.3. The cost of this fuel was assumed to be $20/MMBtu for hydrogen, $30/MMBtu for pipeline gas, and $40/MMBtu for all liquid fuels. The cost estimates for these fuels were influenced by the Princeton Net-Zero America Project[72] and match estimates used in recent work by The Brattle Group in Rhode Island.[73] Cost assumptions were purposefully conservative due to the uncertainties in biomass feedstock supplies and the fact that most biomass supplies are outside of the Northeast and have many competing uses.

The following assumptions were used to yield biogas and liquid fuels at $20/MMBtu and $30/MMbtu respectively:
Biogas at $30/MMBtu:

- A biogas conversion plant costing $2500/kW-output
- Lifetime of 25 years
- Capital recovery factor of 0.1102
- Average utilization of 80%
- Fixed O&M of 3% of capital cost per year
- Variable O&M of $2/MMBtu produced gas
- Delivered biomass cost of $150/dry-ton ($8.34/GJ)
- Conversion efficiency of 1.5 GJ biomass per GJ produced biogas

Liquid fuels at $40/MMBtu:

- Fischer Tropsch Gasification costing $3500/kW-output
- Lifetime of 25 years
- Capital recovery factor of 0.1102
- Average utilization of 80%
- Fixed O&M of 3% of capital cost per year
- Variable O&M of $2/MMBtu produced liquid
- Delivered biomass cost of $150/dry-ton ($8.34/GJ)
- Conversion efficiency of 2 GJ biomass per GJ produced liquids

7.3 Fuel conversion cost, performance and potential

The sources for the cost and performance of conversion technologies are summarized in Table 14Table 14.

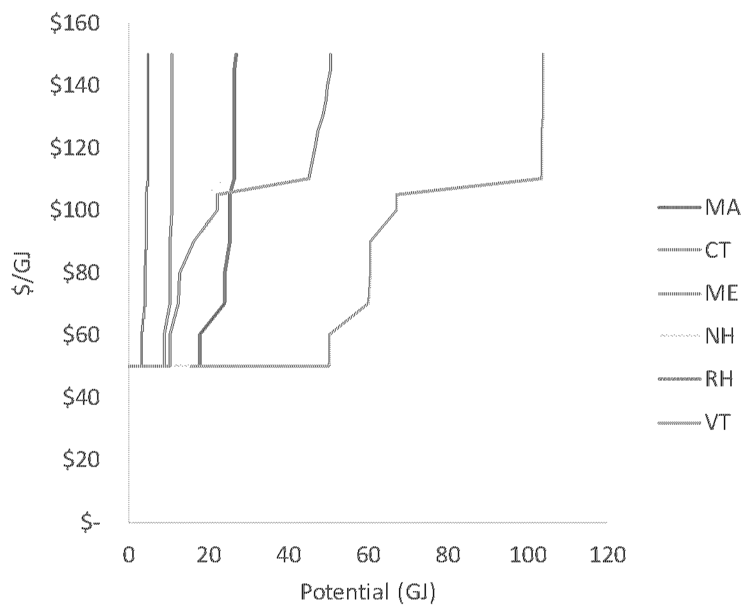
[72] Princeton University, The Net-Zero America Project, https://acee.princeton.edu/rapidswitch/projects/net-zero-america-project/
[73] The Brattle Group, Heating Sector Transformation in Rhode Island, http://www.energy.ri.gov/documents/HST/RI%20HST%20Final%20Pathways%20Report%204-22-20.pdf

Table 14 Conversion technology sources

Technology	Source
Biomass Gasification	G. del Alamo et al.[74]
Biomass Gasification with CCUS	
Renewable Diesel	G. del Alamo et al.
Renewable Diesel with CCUS	
Biomass Pyrolysis	Meerman, J. and E. Larson (2017)[75]
Biomass Pyrolysis with CCUS	
Central-station Hydrogen Electrolysis	Princeton Net-Zero America Project (NZAP)
Power-to-liquids	IEA, The Future of Hydrogen (2018)[76]
Power-to-gas	
Power-to-liquefied petroleum gas	
Direct air capture	Keith et al. (2018)[77]

The availability of bioenergy feedstocks at various price points for each state in New England is summarized by Figure 43 below.

Figure 43 Bioenergy supply curve



[74] IEA Bioenergy, Implementation of Bio-CCS in Biofuels Production, https://www.ieabioenergy.com/wp-content/uploads/2018/08/Implementation-of-bio-CCS-in-biofuels-production_final.pdf
[75]Meerman and Larson 2017 "Negative-carbon drop-in transport fuels produced via catalytic hydropyrolysis of woody biomass with CO2 capture and storage" http://www.rsc.org/suppdata/c7/se/c7se00013h/c7se00013h1.pdf
[76] IEA G20 Hydrogen report: Assumptions, https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf
[77]Keith et al., Joule 2 2018 A Process for Capturing CO2 from the Atmosphere https://www.cell.com/joule/pdf/S2542-4351(18)30225-3.pdf

7.4 Carbon sequestration

Carbon sequestration was allowed across the Northeast in the Regional Coordination pathway at a cost of $71/tonne, inclusive of transport. Costs were derived from National Energy Technology supply curves.[78] It was not necessary to cap this potential because relatively small amounts were used across the region.

7.5 Building heating costs & performance

Residential building cost is based on a technology prospectus developed by Evolved Energy Research. Heating performance data is from NREL's Electrification Futures Study.[79] These are summarized by Table 15 and Table 16, respectively.

Table 15 Residential space heating cost and efficiency. Efficiency values are given for climate zone 5A. Efficiencies vary for other climate zone and come from NREL's Electrification Futures Study, mid-technology scenario.

Category	Technology	Vintage	Capital Cost (2018$/unit)	Install Cost (2018$)	Efficiency (out/in)
Combustion	Reference Natural Gas Furnace	2020	1500	3100	0.90
	Reference Natural Gas Furnace	2030	1500	3100	0.92
	Reference Natural Gas Boiler/Radiator	2020	3400	4482	0.90
	Reference Natural Gas Boiler/Radiator	2030	3400	4482	0.93
	Reference Natural Gas Boiler/Radiator	2040	3400	4482	0.95
	Gas Wall Heater	2020	1500	500	0.90
	Reference Distillate Boiler/Radiator	2020	2654	8357	0.84
	Reference Distillate Furnace	2020	1836	5780	0.83
	Reference Distillate Furnace	2030	1836	5780	0.84
	Reference Kerosene Furnace	2020	2350	5780	0.83
	Reference LPG Furnace	2020	925	5780	0.80
	Reference Natural Gas Heat Pump	2020	11000	2000	1.30
	High Efficiency Distillate Boiler/Radiator	2020	3982	8357	0.91
	High Efficiency Distillate Furnace	2020	2754	5780	0.97
	High Efficiency Kerosene Furnace	2020	3525	5780	0.97
	High Efficiency LPG Furnace	2020	1388	5780	0.98
	High Efficiency Natural Gas Boiler/Radiator	2020	3982	4482	0.96
	High Efficiency Natural Gas Furnace	2020	2625	3100	0.98
Electric	Reference Air Source Heat Pump	2020	8500	2000	2.42
	Reference Air Source Heat Pump	2030	7724	2000	3.02
	Reference Air Source Heat Pump	2040	6948	2000	3.43
	Reference Air Source Heat Pump	2050	6171	2000	3.55
	Ductless Mini-Split Heat Pump	2020	5368	2500	2.55
	Ductless Mini-Split Heat Pump	2030	4878	2500	2.55

[78] NETL CO2 Injection and Storage Cost Model, https://www.netl.doe.gov/projects/files/NETLCO2InjectionandStorageCostModel_020712.pdf

[79] National Renewable Energy Laboratory, Electrification Futures Study, https://www.nrel.gov/analysis/electrification-futures.html

Ductless Mini-Split Heat Pump	2040	4388	2500	2.55
Ductless Mini-Split Heat Pump	2050	3898	2500	2.55
Through-the-wall Heat Pump	2020	600	200	1.82
Reference Geothermal Heat Pump	2020	8500	8500	3.60
Reference Geothermal Heat Pump	2030	7724	8500	3.80
Reference Geothermal Heat Pump	2040	6948	8500	4.00
Reference Geothermal Heat Pump	2050	6171	8500	4.00
Reference Electric Furnace	2020	700	2300	0.99
Reference Electric Unit Heaters	2020	1000	500	0.98

Table 16 Residential water heating cost and efficiency. Efficiency values are given for climate zone 5A. Efficiencies vary for other climate zone and come from NREL's Electrification Futures Study, mid-technology scenario.

Category	Technology	Vintage	Capital Cost (2018$/unit)	Install Cost (2018$)	Efficiency (out/in)
Combustion	Reference Gas Water Heater	2020	1000	480	0.62
	Reference LPG Water Heater	2020	1200	480	0.62
	Reference Distillate Water Heater	2020	1585	640	0.62
	Reference Distillate Water Heater	2030	1575	640	0.62
	High Efficiency Gas Water Heater	2020	1470	480	0.85
	High Efficiency Gas Water Heater	2030	1330	480	0.85
	High Efficiency Gas Water Heater	2040	1280	480	0.85
	High Efficiency LPG Water Heater	2020	1800	530	0.80
	High Efficiency Distillate Water Heater	2020	2500	640	0.68
Electric	Reference Electric Heat Pump Water Heater	2020	1560	320	2.73
	Reference Electric Heat Pump Water Heater	2030	1440	320	3.19
	Reference Electric Heat Pump Water Heater	2040	1320	320	3.41
	Reference Electric Heat Pump Water Heater	2050	1200	320	3.41
	Reference Electric Resistance Water Heater	2020	700	320	0.95

7.6 End-use load shape profiles

Hourly load shapes for different end-uses come from many different sources provided in Table 17. Heating and cooling shapes were weather-matched to 2012.

Table 17 Load shape sources

Shape Name	Used By	Input Data Geography	Input Temporal Resolution	Source
Bulk Electricity System Load	Initial electricity reconciliation, all subsectors not otherwise given a shape	Emissions and Generation Resource Integrated Database (EGRID) with additional granularity in the Western Interconnection	Hourly, 2012	FERC
Light-Duty Vehicles (LDVs)	All LDVs	United States	Month-hour-weekday/weekend	Evolved Energy Research analysis of

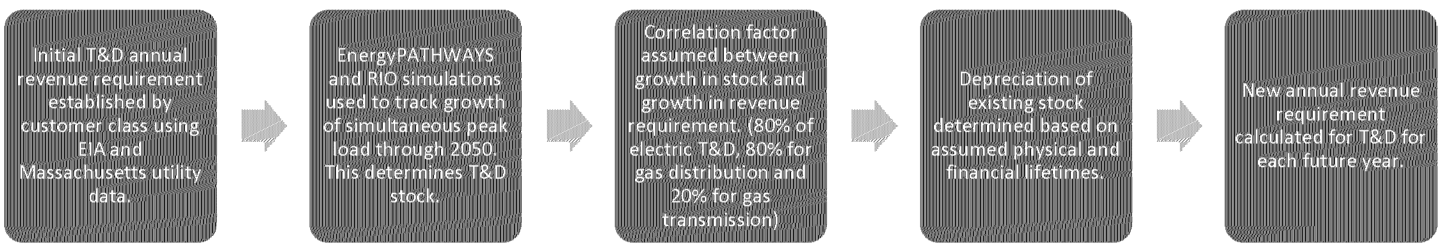
			average, separated by home vs work charging	2016 National Household Travel Survey[80]
Water Heating (Gas Shape)	Residential hot water			Northwest Energy Efficiency Alliance Residential Building Stock Assessment Metering Study (Northwest)[81]
Other Appliances	Residential TV & computers			
Lighting	Residential lighting			
Clothes Washing	Residential clothes washing			
Clothes Drying	Residential clothes drying			
Dishwashing	Residential dish washing			
Residential Refrigeration	Residential refrigeration			
Residential Freezing	Residential freezing			
Residential Cooking	Residential cooking			
Industrial Other	All other industrial loads			California Load Research Data
Agriculture	Industry agriculture			
Commercial Cooking	Commercial cooking			
Commercial Water Heating	Commercial water heating	North American Electric reliability Corporation (NERC) region		EPRI Load Shape Library 5.0[82]
Commercial Lighting Internal	Commercial lighting			
Commercial Refrigeration	Commercial refrigeration			
Commercial Ventilation	Commercial ventilation			
Commercial Office Equipment	Commercial office equipment			
Industrial Machine Drives	Machine drives			
Industrial Process Heating	Process heating			
Electric_furnace_res	Electric resistance heating technologies	IECC Climate Zone by state (114 total geographical regions)	Hourly, 2012 weather	Evolve Energy Research Regressions trained on NREL building simulations in select U.S. cities for a typical meteorological year and then run on county level HDD and CDD for 2102 from the National Oceanic and Atmospheric Administration (NOAA)[83]
Reference_central_ac_res	Central air conditioning technologies			
High_efficiency_central_ac_res	High-efficiency central air conditioning technologies			
Reference_room_ac_res	Room air conditioning technologies			
High_efficiency_room_ac_res	High-efficiency room air conditioning technologies			
Reference_heat_pump_heating_res	ASHPs			
High_efficiency_heat_pump_heating_res	High-efficiency ASHPs			

80 U.S. Department of Transportation Federal Highway Administration, National Household Travel Survey, https://nhts.ornl.gov/
81 Northwest Energy Efficiency Alliance, Residential Building Stock Assessment, https://neea.org/data/residential-building-stock-assessment
82 Electric Power Research Institute, End Use Load Shapes, https://loadshape.epri.com/enduse
83 Completed for and published in the Electrification Futures Study, 2008: https://www.nrel.gov/analysis/electrification-futures.html

Reference_heat_pump_cooling_res	ASHPs			
High_efficiency_heat_pump_cooling_res	High-efficiency ASHPs			
Chiller_com	Commercial chiller technologies			
Dx_ac_com	Direct expansion air conditioning technologies			
Boiler_com	Commercial boiler technologies			
Furnace_com	Commercial electric furnaces			
Flat shape	MDV and HDV charging	United States	n/a	n/a

7.7 Electric & gas delivery infrastructure assumptions

Electricity and gas delivery infrastructure calculations were done in a five-step process explained below. A book-life of 50 years was assumed for gas distribution and 100 years for gas transmission, which became the amount of time needed for an incremental investment to fully depreciate. If throughput in delivery infrastructure drops faster than that asset could be depreciated, the result was increasing rates.



The above calculation resulted in an average electricity distribution growth cost of $205/kW-year.

7.8 Generator cost and potential

Generator cost was derived primarily from NREL ATB 2019[84] and renewable resource potential from the NREL ReEDS model[85]. Regional cost adders for onshore wind and ground-mounted solar PV were added based on the ReEDS model and wind technology market reports. Spreadsheets with each of the values used in the study are available upon request and are summarized at a high level below in Table 18.

[84] "Annual Technology Baseline" (National Renewable Energy Laboratory, 2019; https://atb.nrel.gov/electricity/2019/)

[85] K. Eurek et al. "Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016" (Publication TP-6A20-67067, NREL, 2017; www.nrel.gov/docs/fy17osti/67067.pdf)

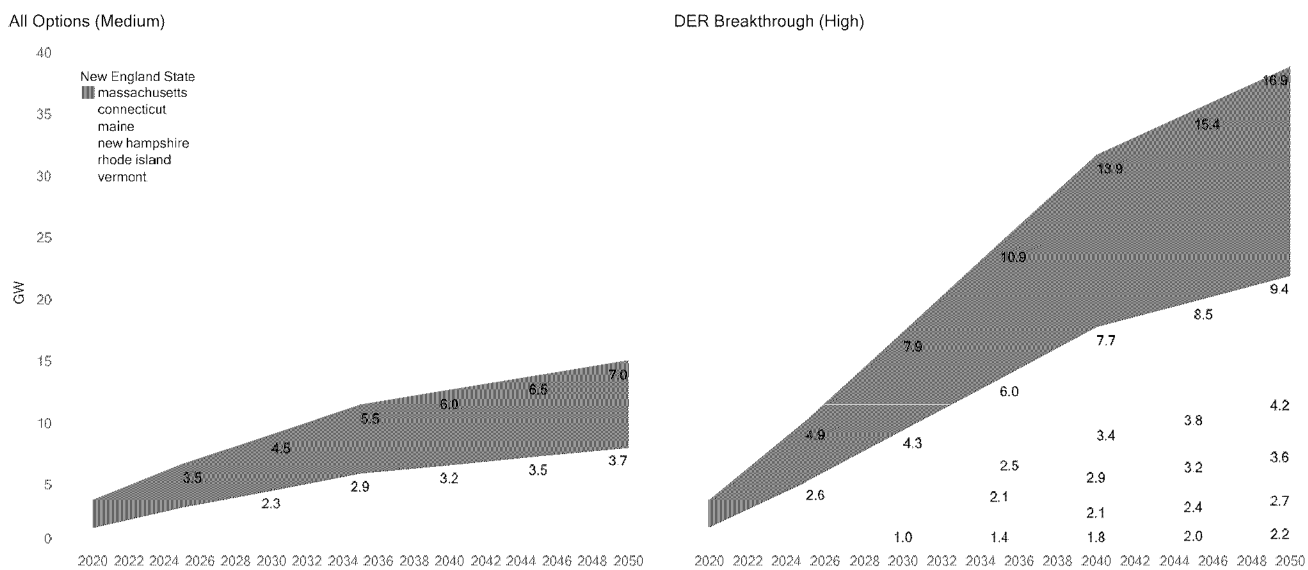
Table 18. Generator cost and potential assumptions.

Data Category	Data Description	Supply Node	Source
Resource Potential	Binned resource potential (GWh) by state with associated resource performance (capacity factors) and transmission costs to reach load.	Transmission – sited Solar PV (6 resource bins); Onshore Wind (7 resource bins); Offshore Wind – Fixed (4 resource bins); Offshore Wind – Floating (8 resource bins)	Eurek et al. 2017[86]
Technology Cost and Performance	Thermal electric technology installed cost projections	Nuclear Power Plants; Combined – Cycle Gas Turbines; Coal Power Plants; Combined – Cycle Gas Power Plants with CCS; Coal Power Plants with CCS; Gas Combustion Turbines	ATB 2019[87]
	Renewable technology installed cost projections	Onshore Wind	ATB 2019 (Mid) w regional multiplier
		Offshore Wind	ATB-Low
		Solar PV	Average of ATB-Mid and ATB-Low with regional multipliers
	Cost and efficiency of other, existing power plant types	Fossil Steam Turbines; Coal Power Plants	T. L. Johnson[88]

7.9 Behind-the-meter solar PV adoption

Adoption assumptions for behind-the-meter solar PV are provided in Figure 44. Adoption assumptions were informed by ISO-NE forecasts and NREL estimates for state-level rooftop PV technical potential.[89]

Figure 44 Behind-the-meter solar PV adoption scenarios by New England state



[86] K. Eurek et al. "Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016" (Publication TP-6A20-67067, NREL, 2017; www.nrel.gov/docs/fy17osti/67067.pdf).
[87] "Annual Technology Baseline" (National Renewable Energy Laboratory, 2019; https://atb.nrel.gov/electricity/2019/).
[88] T. L. Johnson, "MARKAL Scenario Analyses of Technology Options for the Electric Sector: The Impact on Air Quality" (Publication 600/R-06/114, EPA, 20006; https://nepis.epa.gov/Exe/ZyPDF.cgi/P10089YQ.PDF?Dockey=P10089YQ.PDF).
[89] National Renewable Energy Laboratory, Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment, January 2016, https://www.nrel.gov/docs/fy16osti/65298.pdf

7.10 Flexible end-use load

Table 19 Flexible load input assumptions

Electric Load Type	% of load that is flexible by 2050	# hr delay	# hr advance	2050 final electricity demand (TWh)	2050 final energy peak load (GW)
Water heating (res and commercial)	25% (50% in DER Breakthrough)	2 hrs	2 hrs	7.7	2.6
Heating (res and commercial)	15% (25% in DER Breakthrough)	1 hr	1 hr	12.5	13.3
Cooling (res and commercial)	15% (25% in DER Breakthrough)	1 hr	1 hr	2.1	3.7
Light duty vehicles	50% (V2G in DER Breakthrough)	8 hr	0 hr	22.6	10.2
Medium/Heavy duty vehicles	0% (25% in DER Breakthrough)	8 hr	0 hr	3.1	0.7

7.11 Inter-regional transmission flow limits and expansion cost

Assumptions for existing transmission flow limits, transmission losses and the cost expanding interties is summarized in Table 20. Existing transmission capabilities are derived from NREL's Regional Energy Deployment System (ReEDS) Model and ISO-NE documents.[90] The capital cost of expanding transmission between zones is derived from the ReEDS model with adjustments to increase or decrease the cost of inter-regional transmission, based on scenario.

Table 20 Transmission assumptions

Zone A	Zone B	Existing Flow Limit A->B (MW)	Existing Flow Limit B->A (MW)	Losses (%)	Reference Expansion Cost ($/kW)	Regional Coordination pathway Expansion Cost ($/kW)
Connecticut	Rhode Island	1,038	1,038	1.7%	991	496
Massachusetts	Connecticut	1,521	1,521	2.0%	1,161	580
Massachusetts	Rhode Island	1,725	1,725	0.8%	450	225
NE external	New York	2,268	2,268	9.6%	4,701	2351
New Brunswick	Maine	1,000	1,000	3.0%	1,956	978
New Hampshire	Maine	1,300	1,300	1.5%	893	447
New Hampshire	Massachusetts	2,464	2,464	0.7%	417	209
New York	Connecticut	1,139	1,139	1.0%	512	256
New York	Massachusetts	653	653	2.2%	1,010	505
New York	Vermont	242	242	2.8%	1,276	638

[90] National Renewable Energy Laboratory, Regional Energy Deployment System Model, https://www.nrel.gov/analysis/reeds/

Quebec	Maine	-	-	7.0%	1,646	823
Quebec	Massachusetts	2,000	2,000	7.7%	2,586	1293
Quebec	New Brunswick	770	770	7.0%	2,867	1433
Quebec	New York	1,690	1,000	8.1%	3,103	1552
Quebec	Vermont	200	100	6.6%	940	470
Vermont	Massachusetts	2,133	2,133	2.9%	1,676	838
Vermont	New Hampshire	1,796	1,796	2.6%	1,519	760

7.12 Hydro-Quebec operational constraints and expansion cost

New hydro expansion in Quebec within the capacity expansion modeling was priced at $5537/kW in 2016 USD with an average capacity factor of 60.3%. Hydro budgets could be shifted in the optimization by a total of 3 months forward or backward in time compared to historical use. In addition, across the aggregate of dispatchable hydro in Quebec, no more than 20% of the capacity could ramp over each hour, and the minimum generation across the fleet was 30% of the nameplate capacity in every hour. These constraints were informed by past study involving Hydro Quebec.[91]

7.13 Cost of capital & discount rates

The following parameters were used in the RIO and EnergyPATHWAYS models:

- Societal discount rate 2% real
- Demand-side: 3-8% real depending on subsector
- Nuclear 6% real
- Offshore wind 5% real
- All other electricity generation 4% real
- Fuel conversion technologies 10% real

7.14 Demand-side sales share assumptions

Sales shares of demand-technologies were exogenously specified based on expert judgement and a limited number of manual iterations between RIO and EnergyPATHWAYS. Technology adoption is assumed to follow and s-curve pattern. A snapshot of sales shares by decade is provide in Table 21.

Table 21 Demand-technology sales share assumptions for select years.

Subsector	Technology Group	Demand Case	2020	2030	2040	2050
commercial air conditioning	High Efficiency	REFERENCE	4%	9%	11%	11%
commercial air conditioning	High Efficiency	ALL OPTIONS	4%	86%	91%	91%
commercial air conditioning	High Efficiency	LIMITED EFFICIENCY	4%	43%	71%	65%
commercial air conditioning	High Efficiency	PIPELINE GAS	4%	84%	92%	91%
commercial air conditioning	Reference	REFERENCE	96%	91%	89%	89%
commercial air conditioning	Reference	ALL OPTIONS	96%	14%	9%	9%
commercial air conditioning	Reference	LIMITED EFFICIENCY	96%	57%	29%	35%
commercial air conditioning	Reference	PIPELINE GAS	96%	16%	8%	9%

[91] Sustainable Development Solutions Network, Evolved Energy Research, and Hydro-Quebec, Deep Decarbonization in the Northeastern United Stated and Expanded Coordination with Hydro Quebec, April 2018. https://irp-cdn.multiscreensite.com/be6d1d56/files/uploaded/2018.04.05-Northeast-Deep-Decarbonization-Pathways-Study-Final.pdf

commercial cooking	Electric	REFERENCE	37%	39%	38%	38%
commercial cooking	Electric	ALL OPTIONS	37%	89%	97%	97%
commercial cooking	Electric	LIMITED EFFICIENCY	37%	89%	97%	97%
commercial cooking	Electric	PIPELINE GAS	37%	41%	54%	66%
commercial cooking	Reference	REFERENCE	63%	61%	62%	62%
commercial cooking	Reference	ALL OPTIONS	63%	11%	3%	3%
commercial cooking	Reference	LIMITED EFFICIENCY	63%	11%	3%	3%
commercial cooking	Reference	PIPELINE GAS	63%	59%	46%	34%
commercial lighting	High Efficiency	REFERENCE	54%	87%	89%	89%
commercial lighting	High Efficiency	ALL OPTIONS	51%	99%	100%	100%
commercial lighting	High Efficiency	LIMITED EFFICIENCY	54%	87%	89%	89%
commercial lighting	High Efficiency	PIPELINE GAS	51%	99%	100%	100%
commercial lighting	Reference	REFERENCE	46%	13%	11%	11%
commercial lighting	Reference	ALL OPTIONS	49%	1%	0%	0%
commercial lighting	Reference	LIMITED EFFICIENCY	46%	13%	11%	11%
commercial lighting	Reference	PIPELINE GAS	49%	1%	0%	0%
commercial refrigeration	High Efficiency	REFERENCE	0%	12%	15%	17%
commercial refrigeration	High Efficiency	ALL OPTIONS	0%	88%	100%	100%
commercial refrigeration	High Efficiency	LIMITED EFFICIENCY	0%	12%	15%	17%
commercial refrigeration	High Efficiency	PIPELINE GAS	0%	88%	100%	100%
commercial refrigeration	Reference	REFERENCE	100%	88%	85%	83%
commercial refrigeration	Reference	ALL OPTIONS	100%	12%	0%	0%
commercial refrigeration	Reference	LIMITED EFFICIENCY	100%	88%	85%	83%
commercial refrigeration	Reference	PIPELINE GAS	100%	12%	0%	0%
commercial space heating	Electric	REFERENCE	6%	9%	8%	8%
commercial space heating	Electric	ALL OPTIONS	6%	55%	100%	100%
commercial space heating	Electric	LIMITED EFFICIENCY	6%	55%	100%	100%
commercial space heating	Electric	PIPELINE GAS	6%	40%	52%	66%
commercial space heating	High Efficiency	REFERENCE	0%	0%	0%	0%
commercial space heating	High Efficiency	ALL OPTIONS	0%	0%	0%	0%
commercial space heating	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
commercial space heating	High Efficiency	PIPELINE GAS	0%	0%	0%	0%
commercial space heating	Reference	REFERENCE	94%	91%	92%	92%
commercial space heating	Reference	ALL OPTIONS	94%	45%	0%	0%
commercial space heating	Reference	LIMITED EFFICIENCY	94%	45%	0%	0%
commercial space heating	Reference	PIPELINE GAS	94%	60%	48%	34%
commercial ventilation	High Efficiency	ALL OPTIONS	0%	87%	100%	100%
commercial ventilation	High Efficiency	PIPELINE GAS	0%	87%	100%	100%
commercial ventilation	Reference	REFERENCE	100%	100%	100%	100%
commercial ventilation	Reference	ALL OPTIONS	100%	13%	0%	0%
commercial ventilation	Reference	LIMITED EFFICIENCY	100%	100%	100%	100%
commercial ventilation	Reference	PIPELINE GAS	100%	13%	0%	0%
commercial water heating	Electric	REFERENCE	14%	15%	15%	15%
commercial water heating	Electric	ALL OPTIONS	14%	41%	99%	100%

commercial water heating	Electric	LIMITED EFFICIENCY	14%	41%	99%	100%
commercial water heating	Electric	PIPELINE GAS	14%	18%	29%	51%
commercial water heating	High Efficiency	REFERENCE	0%	0%	0%	0%
commercial water heating	High Efficiency	ALL OPTIONS	0%	0%	0%	0%
commercial water heating	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
commercial water heating	High Efficiency	PIPELINE GAS	0%	0%	0%	0%
commercial water heating	Reference	REFERENCE	86%	85%	85%	85%
commercial water heating	Reference	ALL OPTIONS	86%	59%	1%	0%
commercial water heating	Reference	LIMITED EFFICIENCY	86%	59%	1%	0%
commercial water heating	Reference	PIPELINE GAS	86%	82%	71%	49%
residential air conditioning	High Efficiency	REFERENCE	5%	6%	6%	6%
residential air conditioning	High Efficiency	ALL OPTIONS	5%	89%	97%	96%
residential air conditioning	High Efficiency	LIMITED EFFICIENCY	5%	32%	46%	51%
residential air conditioning	High Efficiency	PIPELINE GAS	5%	89%	98%	97%
residential air conditioning	Reference	REFERENCE	95%	94%	94%	94%
residential air conditioning	Reference	ALL OPTIONS	95%	11%	3%	4%
residential air conditioning	Reference	LIMITED EFFICIENCY	95%	68%	54%	49%
residential air conditioning	Reference	PIPELINE GAS	95%	11%	2%	3%
residential building shell	High Efficiency	ALL OPTIONS	0%	100%	100%	100%
residential building shell	High Efficiency	PIPELINE GAS	0%	100%	100%	100%
residential building shell	Reference	REFERENCE	100%	100%	100%	100%
residential building shell	Reference	ALL OPTIONS	100%	0%	0%	0%
residential building shell	Reference	LIMITED EFFICIENCY	100%	100%	100%	100%
residential building shell	Reference	PIPELINE GAS	100%	0%	0%	0%
residential clothes drying	High Efficiency	REFERENCE	0%	0%	0%	0%
residential clothes drying	High Efficiency	ALL OPTIONS	1%	87%	100%	100%
residential clothes drying	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
residential clothes drying	High Efficiency	PIPELINE GAS	1%	87%	100%	100%
residential clothes drying	Reference	REFERENCE	100%	100%	100%	100%
residential clothes drying	Reference	ALL OPTIONS	99%	13%	0%	0%
residential clothes drying	Reference	LIMITED EFFICIENCY	100%	100%	100%	100%
residential clothes drying	Reference	PIPELINE GAS	99%	13%	0%	0%
residential clothes washing	High Efficiency	REFERENCE	0%	0%	0%	0%
residential clothes washing	High Efficiency	ALL OPTIONS	1%	87%	100%	100%
residential clothes washing	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
residential clothes washing	High Efficiency	PIPELINE GAS	1%	87%	100%	100%
residential clothes washing	Reference	REFERENCE	100%	100%	100%	100%
residential clothes washing	Reference	ALL OPTIONS	99%	13%	0%	0%
residential clothes washing	Reference	LIMITED EFFICIENCY	100%	100%	100%	100%
residential clothes washing	Reference	PIPELINE GAS	99%	13%	0%	0%
residential cooking	Electric	REFERENCE	64%	64%	64%	64%
residential cooking	Electric	ALL OPTIONS	64%	95%	100%	100%
residential cooking	Electric	LIMITED EFFICIENCY	64%	95%	100%	100%
residential cooking	Electric	PIPELINE GAS	64%	67%	75%	82%

residential cooking	Reference	REFERENCE	36%	36%	36%	36%
residential cooking	Reference	ALL OPTIONS	36%	5%	0%	0%
residential cooking	Reference	LIMITED EFFICIENCY	36%	5%	0%	0%
residential cooking	Reference	PIPELINE GAS	36%	33%	25%	18%
residential dishwashing	High Efficiency	ALL OPTIONS	1%	87%	100%	100%
residential dishwashing	High Efficiency	PIPELINE GAS	1%	87%	100%	100%
residential dishwashing	Reference	REFERENCE	100%	100%	100%	100%
residential dishwashing	Reference	ALL OPTIONS	99%	13%	0%	0%
residential dishwashing	Reference	LIMITED EFFICIENCY	100%	100%	100%	100%
residential dishwashing	Reference	PIPELINE GAS	99%	13%	0%	0%
residential freezing	High Efficiency	ALL OPTIONS	1%	87%	100%	100%
residential freezing	High Efficiency	PIPELINE GAS	1%	87%	100%	100%
residential freezing	Reference	REFERENCE	100%	100%	100%	100%
residential freezing	Reference	ALL OPTIONS	99%	13%	0%	0%
residential freezing	Reference	LIMITED EFFICIENCY	100%	100%	100%	100%
residential freezing	Reference	PIPELINE GAS	99%	13%	0%	0%
residential lighting	High Efficiency	REFERENCE	47%	81%	83%	82%
residential lighting	High Efficiency	ALL OPTIONS	46%	100%	100%	100%
residential lighting	High Efficiency	LIMITED EFFICIENCY	47%	81%	83%	82%
residential lighting	High Efficiency	PIPELINE GAS	46%	100%	100%	100%
residential lighting	Reference	REFERENCE	53%	19%	17%	18%
residential lighting	Reference	ALL OPTIONS	54%	0%	0%	0%
residential lighting	Reference	LIMITED EFFICIENCY	53%	19%	17%	18%
residential lighting	Reference	PIPELINE GAS	54%	0%	0%	0%
residential refrigeration	High Efficiency	REFERENCE	0%	0%	0%	0%
residential refrigeration	High Efficiency	ALL OPTIONS	1%	87%	100%	100%
residential refrigeration	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
residential refrigeration	High Efficiency	PIPELINE GAS	1%	87%	100%	100%
residential refrigeration	Reference	REFERENCE	100%	100%	100%	100%
residential refrigeration	Reference	ALL OPTIONS	99%	13%	0%	0%
residential refrigeration	Reference	LIMITED EFFICIENCY	100%	100%	100%	100%
residential refrigeration	Reference	PIPELINE GAS	99%	13%	0%	0%
residential space heating	Electric	REFERENCE	14%	16%	16%	16%
residential space heating	Electric	ALL OPTIONS	14%	58%	95%	96%
residential space heating	Electric	LIMITED EFFICIENCY	14%	58%	95%	96%
residential space heating	Electric	PIPELINE GAS	14%	45%	58%	70%
residential space heating	High Efficiency	REFERENCE	0%	0%	0%	0%
residential space heating	High Efficiency	ALL OPTIONS	0%	0%	0%	0%
residential space heating	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
residential space heating	High Efficiency	PIPELINE GAS	0%	0%	0%	0%
residential space heating	Reference	REFERENCE	86%	84%	84%	84%
residential space heating	Reference	ALL OPTIONS	86%	42%	5%	4%
residential space heating	Reference	LIMITED EFFICIENCY	86%	42%	5%	4%
residential space heating	Reference	PIPELINE GAS	86%	55%	42%	30%

residential water heating	Electric	REFERENCE	31%	47%	47%	47%
residential water heating	Electric	ALL OPTIONS	31%	68%	100%	100%
residential water heating	Electric	LIMITED EFFICIENCY	31%	68%	100%	100%
residential water heating	Electric	PIPELINE GAS	31%	56%	65%	76%
residential water heating	High Efficiency	REFERENCE	0%	0%	0%	0%
residential water heating	High Efficiency	ALL OPTIONS	0%	0%	0%	0%
residential water heating	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
residential water heating	High Efficiency	PIPELINE GAS	0%	0%	0%	0%
residential water heating	Reference	REFERENCE	69%	53%	53%	53%
residential water heating	Reference	ALL OPTIONS	69%	32%	0%	0%
residential water heating	Reference	LIMITED EFFICIENCY	69%	32%	0%	0%
residential water heating	Reference	PIPELINE GAS	69%	44%	35%	24%
heavy duty trucks	Electric	REFERENCE	0%	0%	0%	0%
heavy duty trucks	Electric	ALL OPTIONS	0%	17%	61%	64%
heavy duty trucks	Electric	LIMITED EFFICIENCY	0%	17%	61%	64%
heavy duty trucks	Electric	PIPELINE GAS	0%	17%	61%	64%
heavy duty trucks	High Efficiency	REFERENCE	0%	0%	0%	0%
heavy duty trucks	High Efficiency	ALL OPTIONS	0%	0%	0%	0%
heavy duty trucks	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
heavy duty trucks	High Efficiency	PIPELINE GAS	0%	0%	0%	0%
heavy duty trucks	Reference	REFERENCE	100%	99%	99%	99%
heavy duty trucks	Reference	ALL OPTIONS	99%	81%	13%	0%
heavy duty trucks	Reference	LIMITED EFFICIENCY	99%	81%	13%	0%
heavy duty trucks	Reference	PIPELINE GAS	99%	81%	13%	0%
heavy duty trucks	Hydrogen	REFERENCE	0%	0%	0%	0%
heavy duty trucks	Hydrogen	ALL OPTIONS	0%	2%	26%	36%
heavy duty trucks	Hydrogen	LIMITED EFFICIENCY	0%	2%	26%	36%
heavy duty trucks	Hydrogen	PIPELINE GAS	0%	2%	26%	36%
light duty autos	Electric	REFERENCE	6%	11%	16%	19%
light duty autos	Electric	ALL OPTIONS	6%	66%	98%	100%
light duty autos	Electric	LIMITED EFFICIENCY	6%	66%	98%	100%
light duty autos	Electric	PIPELINE GAS	6%	66%	98%	100%
light duty autos	High Efficiency	REFERENCE	6%	10%	11%	11%
light duty autos	High Efficiency	ALL OPTIONS	6%	4%	0%	0%
light duty autos	High Efficiency	LIMITED EFFICIENCY	6%	4%	0%	0%
light duty autos	High Efficiency	PIPELINE GAS	6%	4%	0%	0%
light duty autos	Reference	REFERENCE	88%	79%	73%	70%
light duty autos	Reference	ALL OPTIONS	88%	30%	2%	0%
light duty autos	Reference	LIMITED EFFICIENCY	88%	30%	2%	0%
light duty autos	Reference	PIPELINE GAS	88%	30%	2%	0%
light duty autos	Hydrogen	REFERENCE	0%	0%	0%	0%
light duty autos	Hydrogen	ALL OPTIONS	0%	0%	0%	0%
light duty autos	Hydrogen	LIMITED EFFICIENCY	0%	0%	0%	0%
light duty autos	Hydrogen	PIPELINE GAS	0%	0%	0%	0%

light duty trucks	Electric	REFERENCE	1%	2%	3%	5%
light duty trucks	Electric	ALL OPTIONS	1%	40%	98%	100%
light duty trucks	Electric	LIMITED EFFICIENCY	1%	40%	98%	100%
light duty trucks	Electric	PIPELINE GAS	1%	40%	98%	100%
light duty trucks	High Efficiency	REFERENCE	1%	3%	4%	6%
light duty trucks	High Efficiency	ALL OPTIONS	1%	2%	0%	0%
light duty trucks	High Efficiency	LIMITED EFFICIENCY	1%	2%	0%	0%
light duty trucks	High Efficiency	PIPELINE GAS	1%	2%	0%	0%
light duty trucks	Reference	REFERENCE	98%	94%	92%	89%
light duty trucks	Reference	ALL OPTIONS	98%	58%	2%	0%
light duty trucks	Reference	LIMITED EFFICIENCY	98%	58%	2%	0%
light duty trucks	Reference	PIPELINE GAS	98%	58%	2%	0%
light duty trucks	Hydrogen	REFERENCE	0%	0%	0%	0%
light duty trucks	Hydrogen	ALL OPTIONS	0%	0%	0%	0%
light duty trucks	Hydrogen	LIMITED EFFICIENCY	0%	0%	0%	0%
light duty trucks	Hydrogen	PIPELINE GAS	0%	0%	0%	0%
medium duty trucks	Electric	REFERENCE	0%	0%	1%	1%
medium duty trucks	Electric	ALL OPTIONS	0%	19%	67%	70%
medium duty trucks	Electric	LIMITED EFFICIENCY	0%	19%	67%	70%
medium duty trucks	Electric	PIPELINE GAS	0%	19%	67%	70%
medium duty trucks	High Efficiency	REFERENCE	0%	0%	0%	1%
medium duty trucks	High Efficiency	ALL OPTIONS	0%	0%	0%	0%
medium duty trucks	High Efficiency	LIMITED EFFICIENCY	0%	0%	0%	0%
medium duty trucks	High Efficiency	PIPELINE GAS	0%	0%	0%	0%
medium duty trucks	Reference	REFERENCE	100%	99%	98%	98%
medium duty trucks	Reference	ALL OPTIONS	99%	80%	11%	0%
medium duty trucks	Reference	LIMITED EFFICIENCY	99%	80%	11%	0%
medium duty trucks	Reference	PIPELINE GAS	99%	80%	11%	0%
medium duty trucks	Hydrogen	REFERENCE	0%	0%	0%	0%
medium duty trucks	Hydrogen	ALL OPTIONS	0%	1%	22%	30%
medium duty trucks	Hydrogen	LIMITED EFFICIENCY	0%	1%	22%	30%
medium duty trucks	Hydrogen	PIPELINE GAS	0%	1%	22%	30%
transit buses	Electric	REFERENCE	1%	1%	1%	1%
transit buses	Electric	ALL OPTIONS	1%	50%	99%	100%
transit buses	Electric	LIMITED EFFICIENCY	1%	50%	99%	100%
transit buses	Electric	PIPELINE GAS	1%	50%	99%	100%
transit buses	High Efficiency	REFERENCE	19%	19%	19%	19%
transit buses	High Efficiency	ALL OPTIONS	17%	9%	0%	0%
transit buses	High Efficiency	LIMITED EFFICIENCY	17%	9%	0%	0%
transit buses	High Efficiency	PIPELINE GAS	17%	9%	0%	0%
transit buses	Reference	REFERENCE	80%	80%	80%	80%
transit buses	Reference	ALL OPTIONS	82%	41%	1%	0%
transit buses	Reference	LIMITED EFFICIENCY	82%	41%	1%	0%
transit buses	Reference	PIPELINE GAS	82%	41%	1%	0%

8 Appendix 2: Supplemental results

Figure 45 Annual energy and industrial emissions for ISO-NE states for each pathway. All pathways achieve the regional target of 10.2 Mt net E&I emissions in 2050 (100% renewable primary scenario reaches -2.2 Mt).

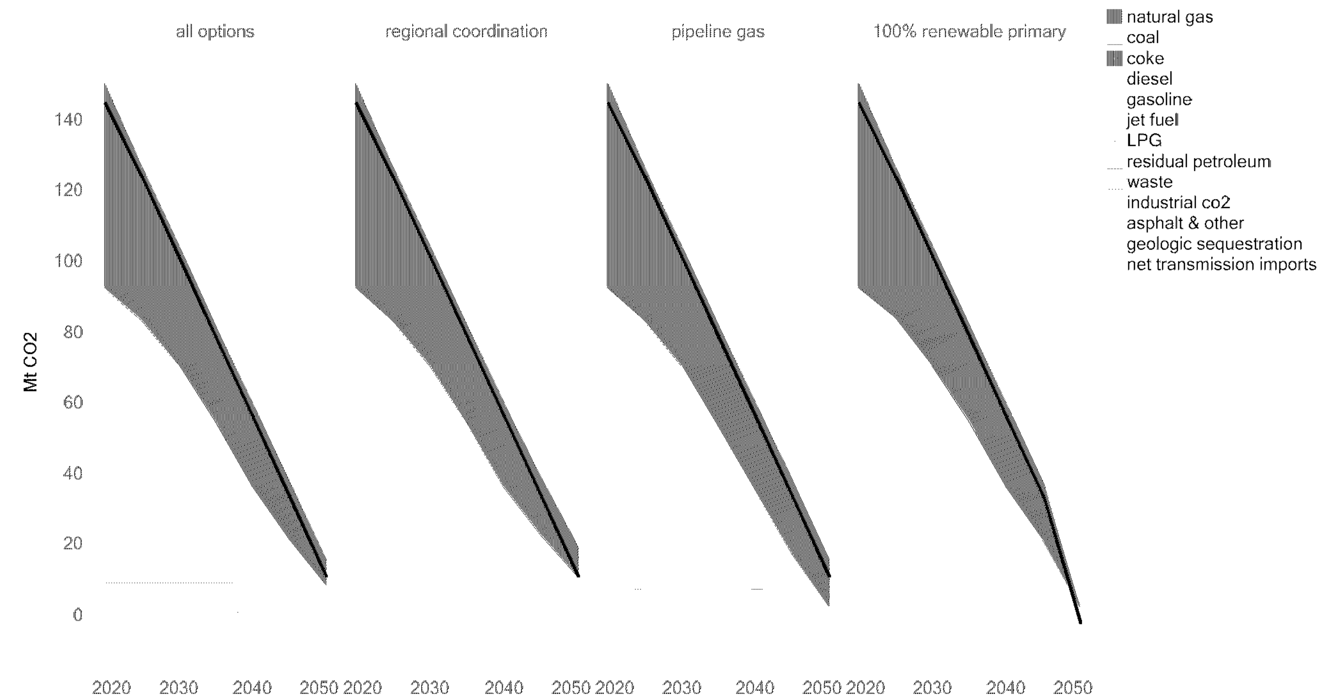


Figure 46 Cumulative E&I emissions for ISO-NE states for the All Options pathway compared against reference.

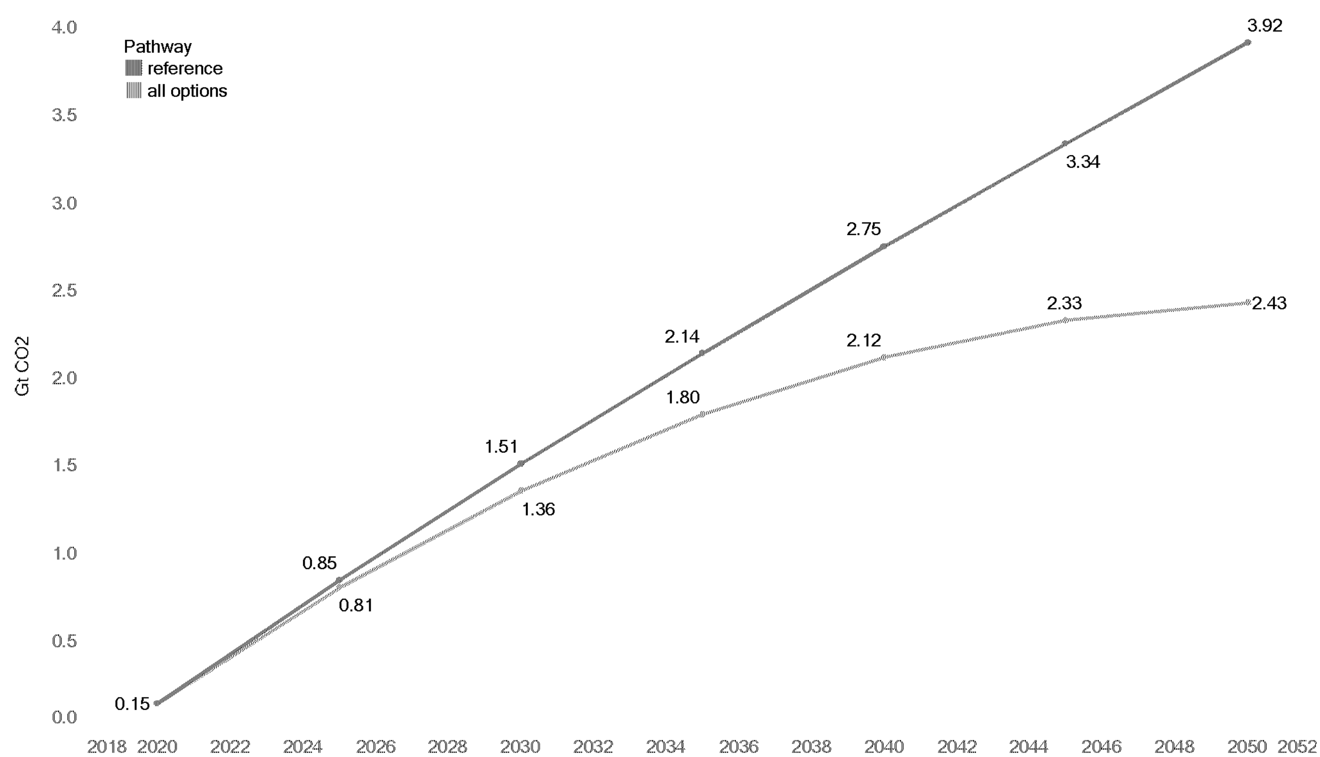


Figure 47 Massachusetts annual E&I CO_2 emissions for all pathways

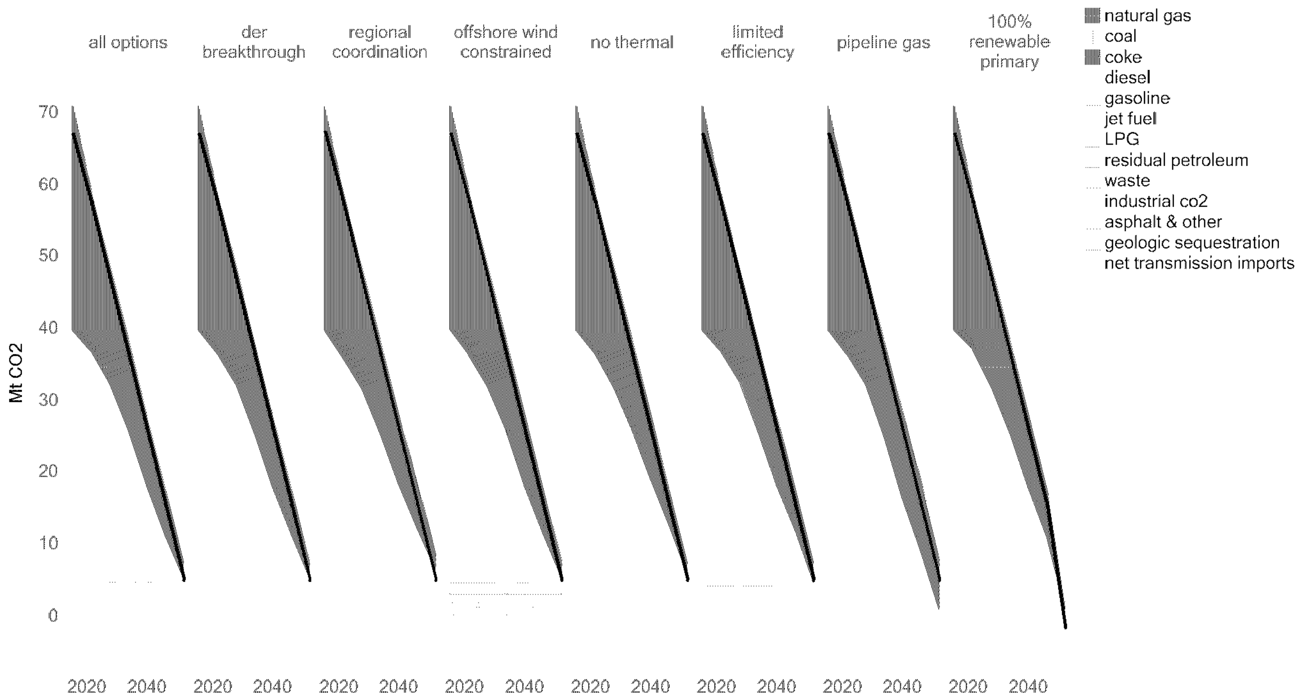


Figure 48 Difference in final energy demand compared to the reference scenario for Massachusetts. Area above the x-axis represents final energy consumption above that in the reference case, area below the x-axis represents a reduction in final energy consumption compared to reference. Final energy types that show no appreciable change vs. the reference case have been eliminated from the legend.

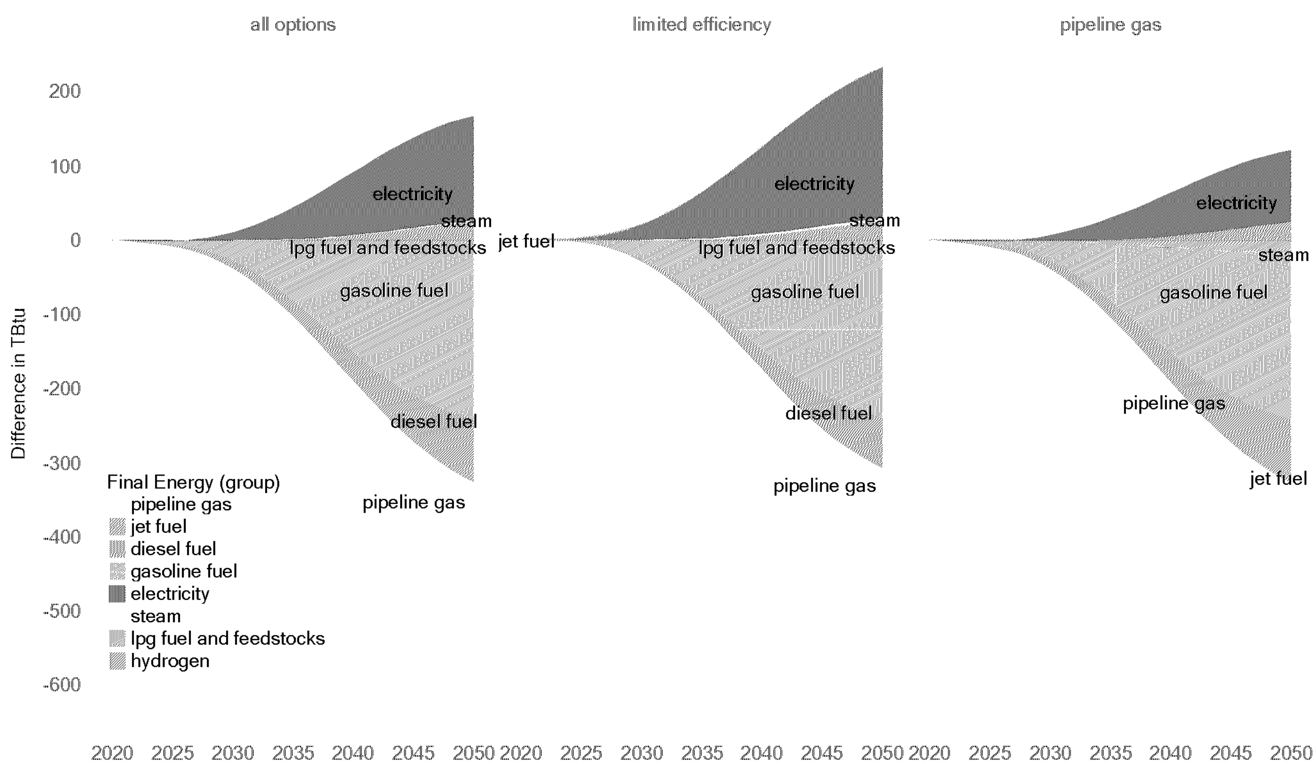


Figure 49 Regional final energy demand for ISO-NE states.

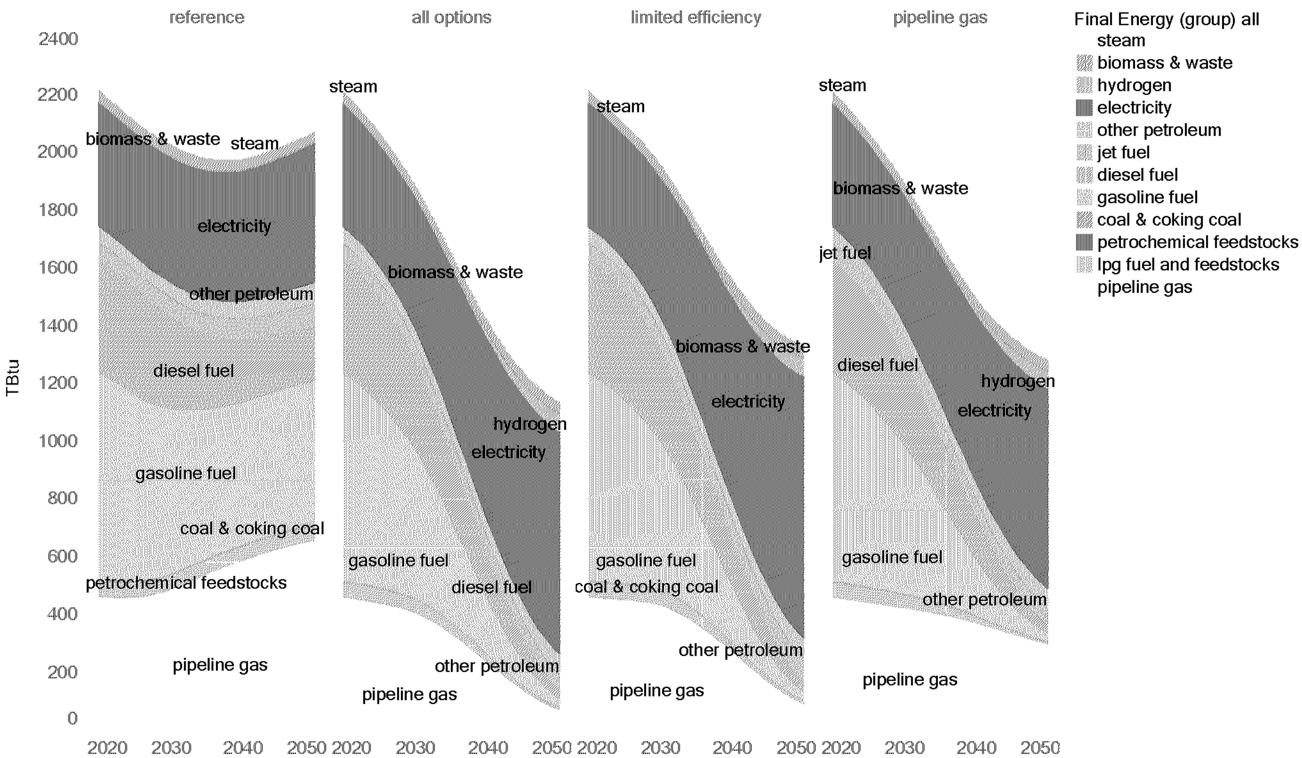


Figure 50 Massachusetts residential heating service demand. The allocation of service demand to a final energy type is shown by the stacked area. Trends in building shell and HDD lead to modest reductions in the baseline space heating demand. Aggressive building shell measures in the All Options and Pipeline Gas pathways reduce space heating service demand to 70% of the baseline. High efficiency washing machines and dish washers result in a drop in demand for hot water.

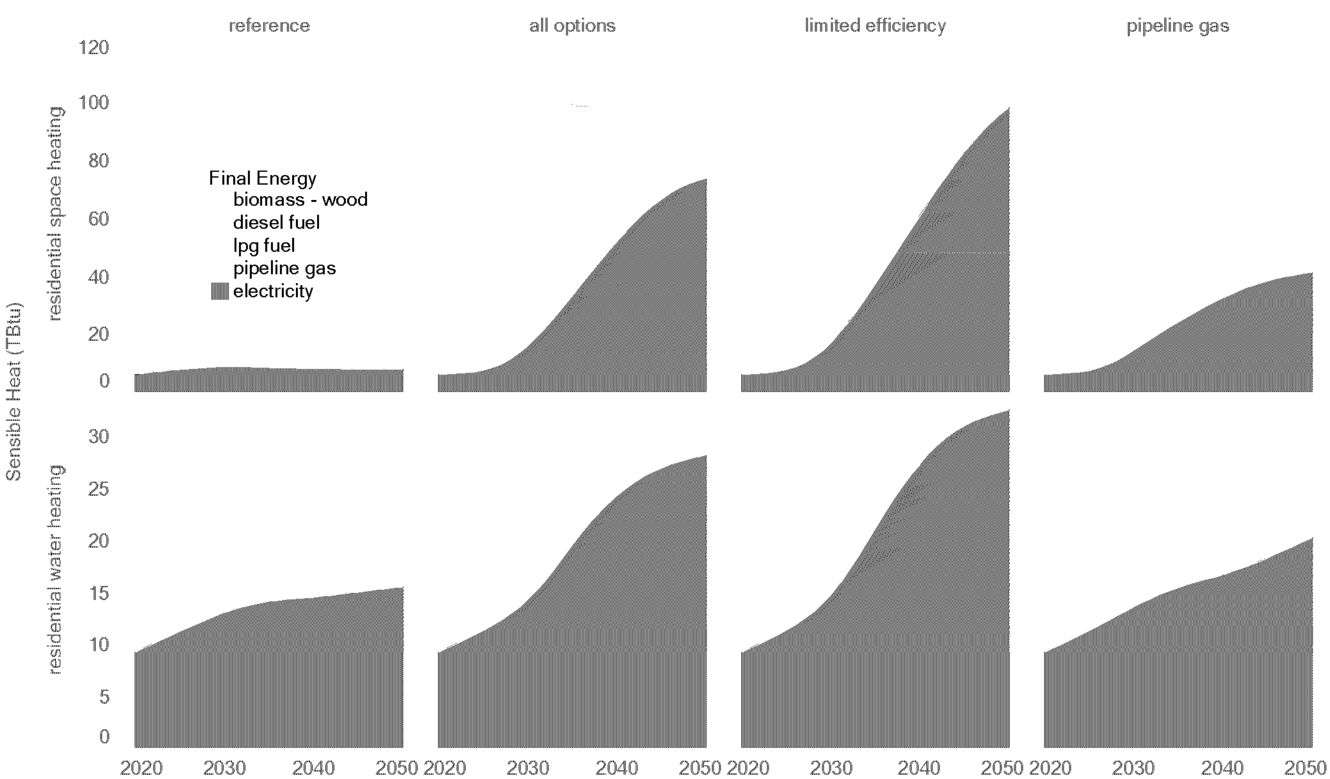


Figure 51 Electricity shapes for the Limited Efficiency pathway divided into heating, transport, and other. This shape is before the impact of any load shifting for applications like transport.

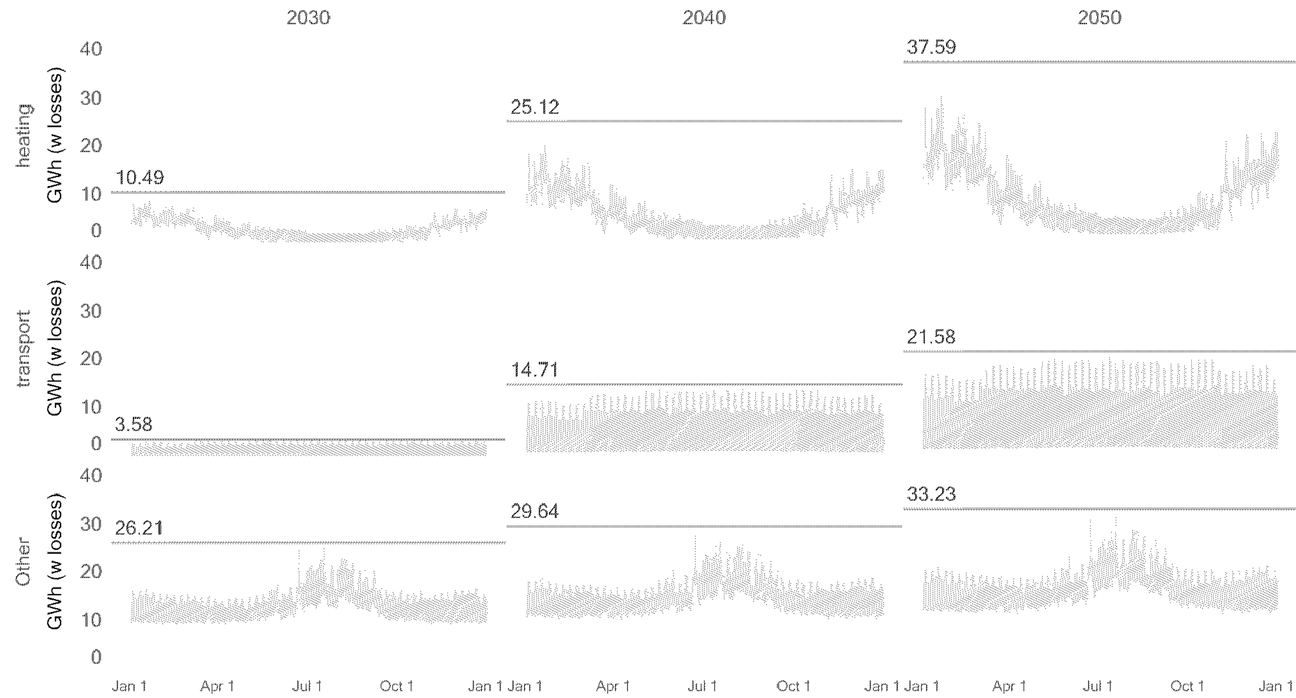


Figure 52 ISO-NE system load shape comparisons, excluding transportation load. Transportation is shown in additional figures below, but for comparability with Quebec, is excluded here. All modeling used a 2012 weather year. The first panel shows the 2020 ISO-NE load, the second shows load in 2050 in the All Options pathway, and the third panel shows Quebec's current load shape. Quebec already has high building heating electrification today, making it useful as an empirical comparison (differences between New England and Quebec include: Quebec has about half the number of households; heating is primarily electric resistance; and the climate is colder). The maximum and average load values are displayed and the load factor (excluding transportation) for ISO-NE decreases from 57.1% in 2020 to 46.8% in 2050.

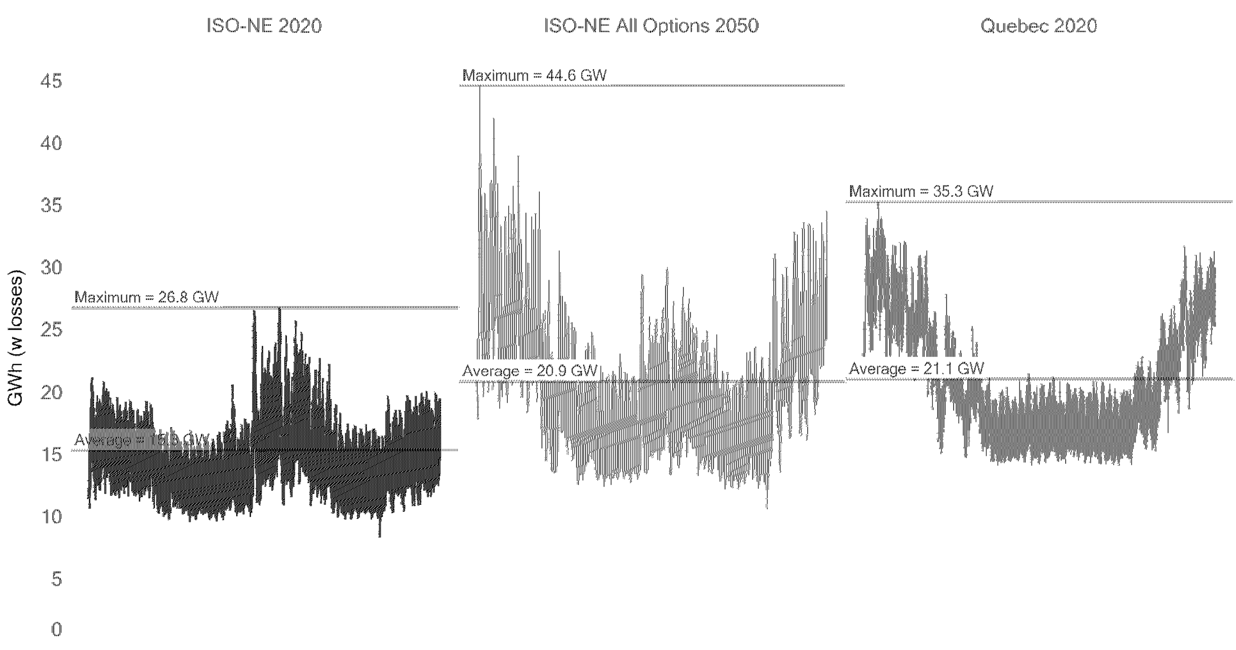


Table 22 Massachusetts electricity supply for all pathways between 2020 and 2050 separated by resource (TWh).

Pathway name	Resource	2020	2025	2030	2035	2040	2045	2050
all options	ground-mounted pv	1.6	1.4	1.7	1.9	7.9	19.8	29.4
all options	rooftop pv	3	4	5.5	7.1	7.7	8.3	8.3
all options	offshore wind floating	0	0	0.2	1.5	13.8	30.3	47.1
all options	offshore wind fixed	0	0.1	12.8	25	30.2	28.5	28.8
all options	onshore wind	0.5	1.1	2	1.7	1.8	1.6	1.7
all options	hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.8
all options	oil	0.2	0.1	0	0	0	0	0
all options	msw	1	0	0	0	0	0	0
all options	nuclear	0	0	0	0	0	0	0
all options	biomass	0.2	0.3	0.3	0.2	0.2	0.2	0.2
all options	biomass w cc	0	0	0	0	0	0	0
all options	net transmission flow	10.1	28	30.8	32.3	23.3	18.2	16.7
all options	gas w cc	0	0	0	0	0	0	0
all options	gas	41.3	21.3	9.1	4.4	4.7	4.3	1.1
der breakthrough	ground-mounted pv	1.6	1.3	1.4	1.5	1.4	4.4	13.6
der breakthrough	rooftop pv	3	5.6	9.7	14	17.8	20.1	20.6
der breakthrough	offshore wind floating	0	0	0.2	1.5	13.2	31.4	49.3
der breakthrough	offshore wind fixed	0	0.2	10.5	21.6	30.3	28.9	29
der breakthrough	onshore wind	0.5	1.1	2	1.7	1.8	1.6	1.7
der breakthrough	hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.8
der breakthrough	oil	0.2	0.1	0	0	0	0	0
der breakthrough	msw	1	0	0	0	0	0	0
der breakthrough	nuclear	0	0	0	0	0	0	0
der breakthrough	biomass	0.2	0.3	0.3	0.2	0.2	0.2	0.2
der breakthrough	biomass w cc	0	0	0	0	0	0	0
der breakthrough	net transmission flow	10.1	25.8	29.1	28.3	19.6	20.3	18
der breakthrough	gas w cc	0	0	0	0	0	0	0
der breakthrough	gas	41.2	22	9.3	5.4	5.4	4	1.1
regional coordination	ground-mounted pv	1.6	1.3	1.4	1.5	3.8	5.8	23.6
regional coordination	rooftop pv	3	4	5.5	7.1	7.7	8.5	8.5
regional coordination	offshore wind floating	0	0	0.2	0.4	8.1	25	42
regional coordination	offshore wind fixed	0	0	5.5	19.9	31.3	29.9	30
regional coordination	onshore wind	0.5	1.1	2	1.7	1.8	1.7	1.7
regional coordination	hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.8
regional coordination	oil	0.2	0.1	0	0	0	0	0
regional coordination	msw	1	0	0	0	0	0	0
regional coordination	nuclear	0	0	0	0	0	0	0
regional coordination	biomass	0.2	0.3	0.3	0.2	0.2	0.2	0.2
regional coordination	biomass w cc	0	0	0	0	0	0	0
regional coordination	net transmission flow	10.2	25.6	36.5	37.2	32.3	32.5	18.4
regional coordination	gas w cc	0	0	0	0	0	0	0
regional coordination	gas	41.1	23.9	10.9	5.9	3.4	3.4	0.4

offshore wind constrained	ground-mounted pv	1.6	2	2.9	3.9	13.4	23.1	30.1
offshore wind constrained	rooftop pv	3	4	5.5	7.1	7.7	8.6	8.6
offshore wind constrained	offshore wind floating	0	0	0.1	0.1	1.5	8.6	19.3
offshore wind constrained	offshore wind fixed	0	0	7.3	15.7	25.7	28.1	28.5
offshore wind constrained	onshore wind	0.5	1.1	2	2	2.7	2.5	2.5
offshore wind constrained	hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.8
offshore wind constrained	oil	0.2	0.1	0	0	0	0	0
offshore wind constrained	msw	1	0	0	0	0	0	0
offshore wind constrained	nuclear	0	0	0	0	0	0	0
offshore wind constrained	biomass	0.2	0.3	0.3	0.2	0.2	0.2	0.2
offshore wind constrained	biomass w cc	0	0	0	0	0	0	0
offshore wind constrained	net transmission flow	10.1	26.1	34.2	40.7	33.5	35.4	35.8
offshore wind constrained	gas w cc	0	0	0	0	0	0	0
offshore wind constrained	gas	41.2	22.7	10.1	4.4	4.2	3.7	0.4
no thermal	ground-mounted pv	1.6	2.6	4.2	5.9	23.1	35.9	61.4
no thermal	rooftop pv	3	4	5.5	7.1	7.5	6.9	5.9
no thermal	offshore wind floating	0	0	0.3	0.6	1.6	23.3	41.6
no thermal	offshore wind fixed	0	0.1	13.3	25.9	29.9	26.1	21.3
no thermal	onshore wind	0.5	1.1	2	1.7	2	1.4	1.3
no thermal	hydro	0.9	0.9	0.9	0.9	0.8	0.6	0.4
no thermal	oil	0.2	0.1	0	0	0	0	0
no thermal	msw	1	0.9	0.9	0.9	0.9	0.9	0
no thermal	nuclear	0	0	0	0	0	0	0
no thermal	biomass	0.2	0.3	0.3	0.2	0.2	0.1	0.1
no thermal	biomass w cc	0	0	0	0	0	0	0
no thermal	net transmission flow	10	25.2	25.4	27.5	22.5	17.8	4
no thermal	gas w cc	0	0	0	0	0	0	0
no thermal	gas	41.3	22.1	10.3	4.3	1.8	0.3	0
limited efficiency	ground-mounted pv	1.6	1.3	1.4	1.5	12.6	24	29.3
limited efficiency	rooftop pv	3	4	5.5	7.1	7.7	8.5	8.3
limited efficiency	offshore wind floating	0	0	0.4	1.7	25.9	51.8	60.8
limited efficiency	offshore wind fixed	0	0	10.1	29.1	30.7	29.3	29.1
limited efficiency	onshore wind	0.5	1.1	2	1.7	1.8	1.7	1.7
limited efficiency	hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.8
limited efficiency	oil	0.2	0.1	0	0	0	0	0
limited efficiency	msw	1	0	0	0	0	0	0
limited efficiency	nuclear	0	0	0	0	0	0	0
limited efficiency	biomass	0.2	0.3	0.3	0.2	0.2	0.2	0.2
limited efficiency	biomass w cc	0	0	0	0	0	0	0
limited efficiency	net transmission flow	10	30.2	39.9	36.9	19.3	10.9	20
limited efficiency	gas w cc	0	0	0	0	0	0	0
limited efficiency	gas	41.3	20.5	6.5	2.5	2.6	2.9	1.1
pipeline gas	ground-mounted pv	1.6	1.7	2.3	2.8	12.9	23.1	29.3
pipeline gas	rooftop pv	3	4	5.5	7.1	7.7	8.5	8.3

pipeline gas	offshore wind floating	0	0	0.2	1.5	16.2	41.2	40.3
pipeline gas	offshore wind fixed	0	0.2	10.9	20.2	30.5	29.1	29
pipeline gas	onshore wind	0.5	1.1	2	1.7	1.8	1.7	1.7
pipeline gas	hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.8
pipeline gas	oil	0.2	0.1	0	0	0	0	0
pipeline gas	msw	1	0	0	0	0	0	0
pipeline gas	nuclear	0	0	0	0	0	0	0
pipeline gas	biomass	0.2	0.3	0.3	0.2	0.2	0.2	0.2
pipeline gas	biomass w cc	0	0	0	0	0	0	0
pipeline gas	net transmission flow	10	26.5	31.9	33.9	11.3	0.7	11.7
pipeline gas	gas w cc	0	0	0	0	0	0	0
pipeline gas	gas	41.3	22.3	8.4	2.4	1.8	0.7	0.2
100% renewable primary	ground-mounted pv	1.6	1.7	2.2	2.7	3.1	17.3	29.6
100% renewable primary	rooftop pv	3	4	5.5	7.1	7.7	8.3	8.4
100% renewable primary	offshore wind floating	0	0	0.1	1.5	18.6	33.5	43.8
100% renewable primary	offshore wind fixed	0	1.6	16	28.3	29.8	28.1	28.6
100% renewable primary	onshore wind	0.5	1.1	2	1.7	1.8	1.6	1.7
100% renewable primary	hydro	0.9	0.9	0.9	0.9	0.9	0.9	0.8
100% renewable primary	oil	0.2	0.1	0	0	0	0	0
100% renewable primary	msw	1	0	0	0	0	0	0
100% renewable primary	nuclear	0	0	0	0	0	0	0
100% renewable primary	biomass	0.2	0.3	0.3	0.2	0.2	0.2	0.2
100% renewable primary	biomass w cc	0	0	0	0	0	0	0
100% renewable primary	net transmission flow	10.1	26.8	26.3	27.5	23.2	16.3	15.3
100% renewable primary	gas w cc	0	0	0	0	0	0	0
100% renewable primary	gas	41.3	20.8	10.1	5.2	5	4.5	1

Figure 53 ISO-NE installed capacity by year across pathways.

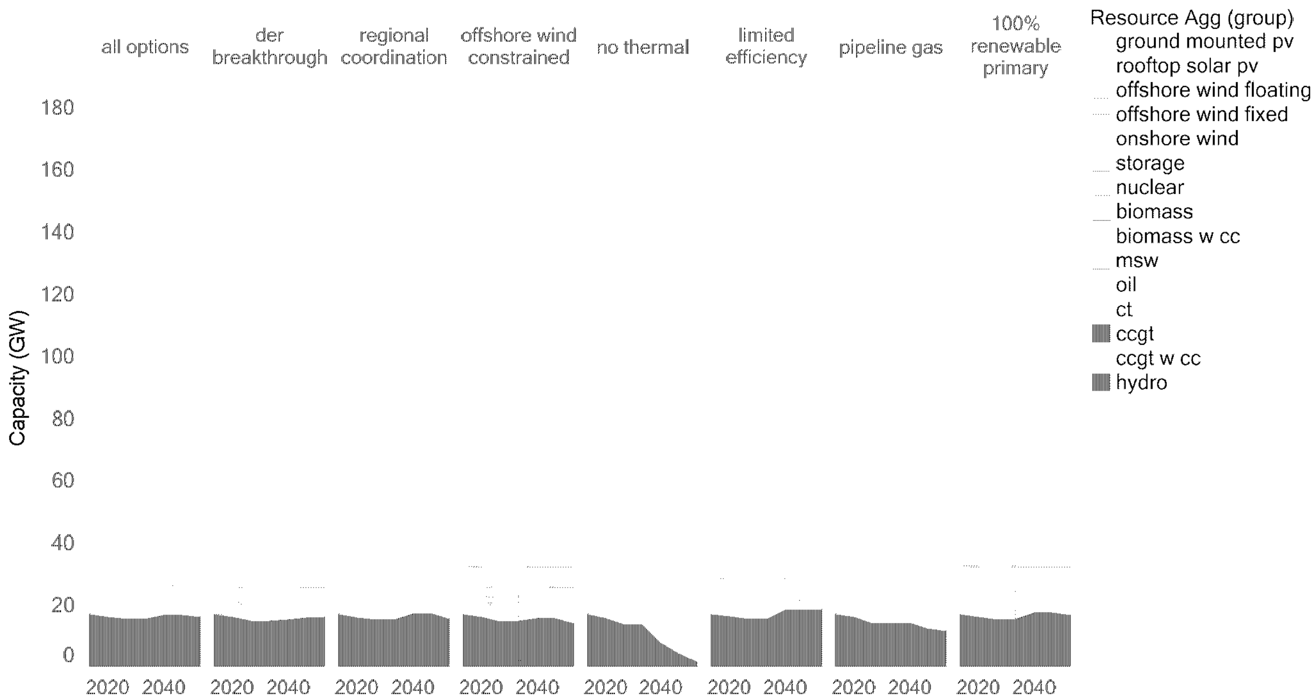


Figure 54 Electricity supply in the Offshore Wind Constrained pathway for each zone in the Northeast.

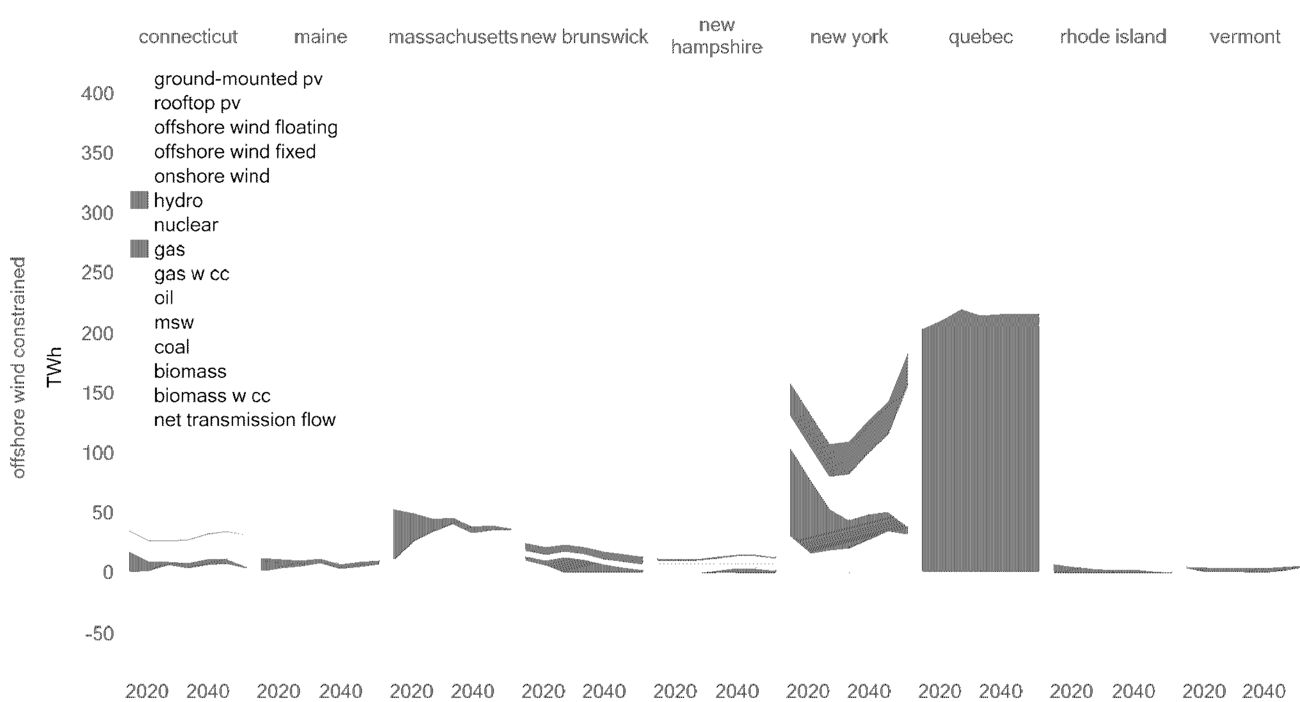


Figure 55 Electricity supply in the No Thermal pathway for each zone in the Northeast.

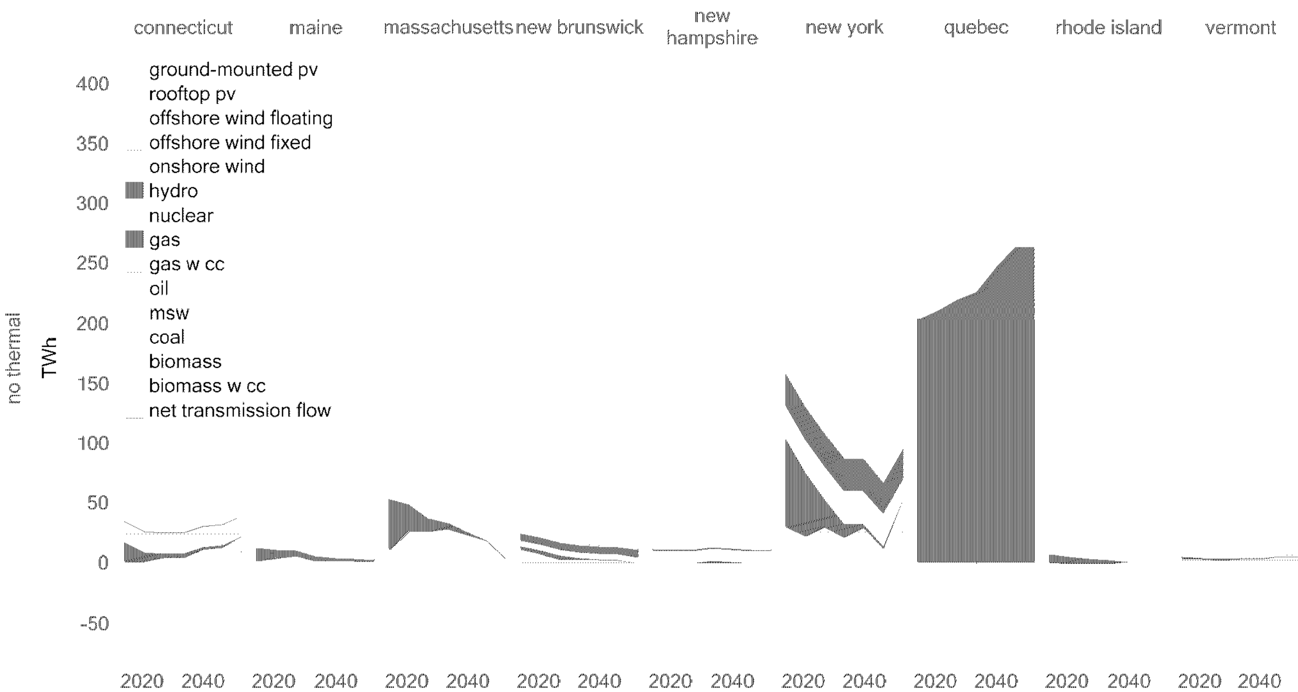


Figure 56 Zonal electricity generation shares for each pathway

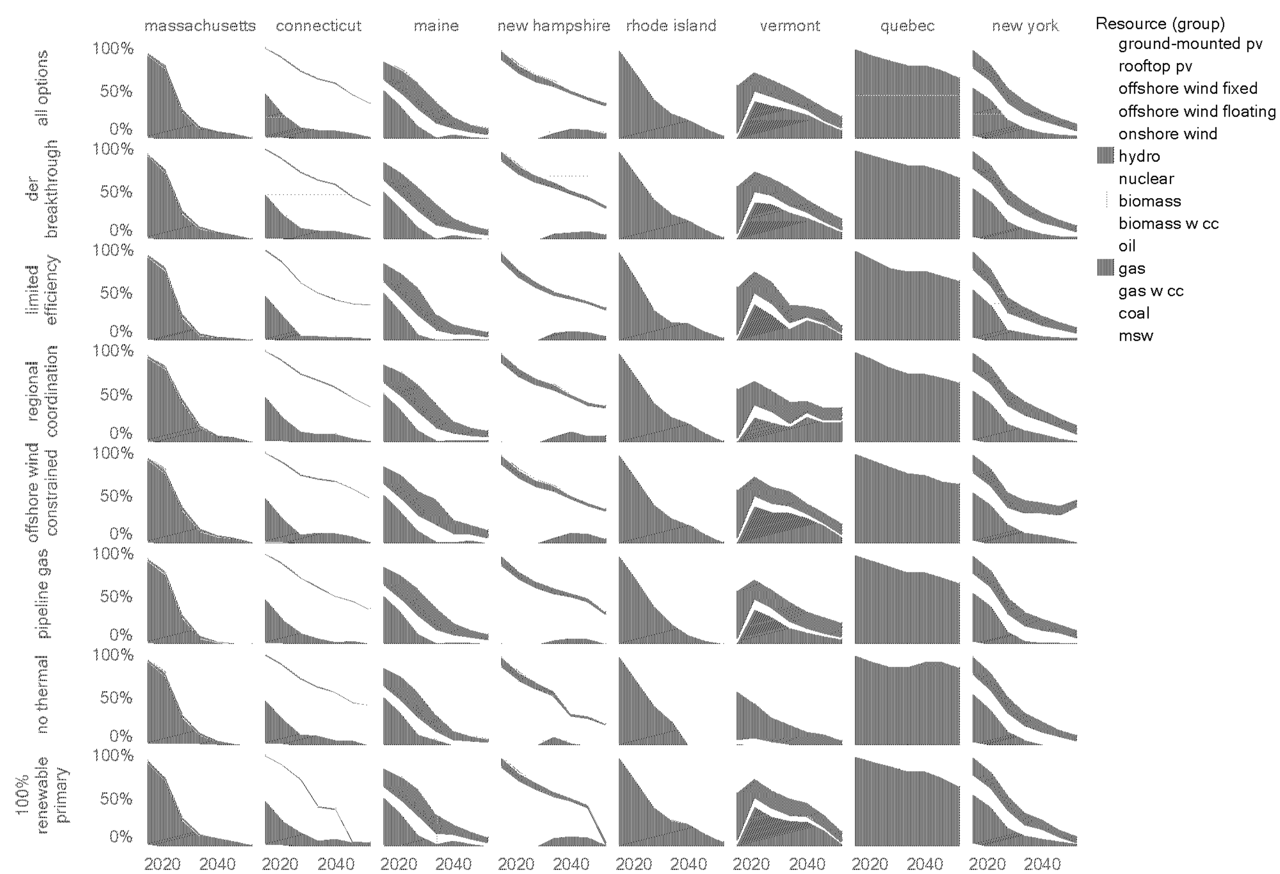


Figure 57 Transmission maps showing total 2050 transfer capability between zones. Heavier lines (color and width) represent a larger transfer capability. The six pathways displayed were selected because of their contrasting transmission features.

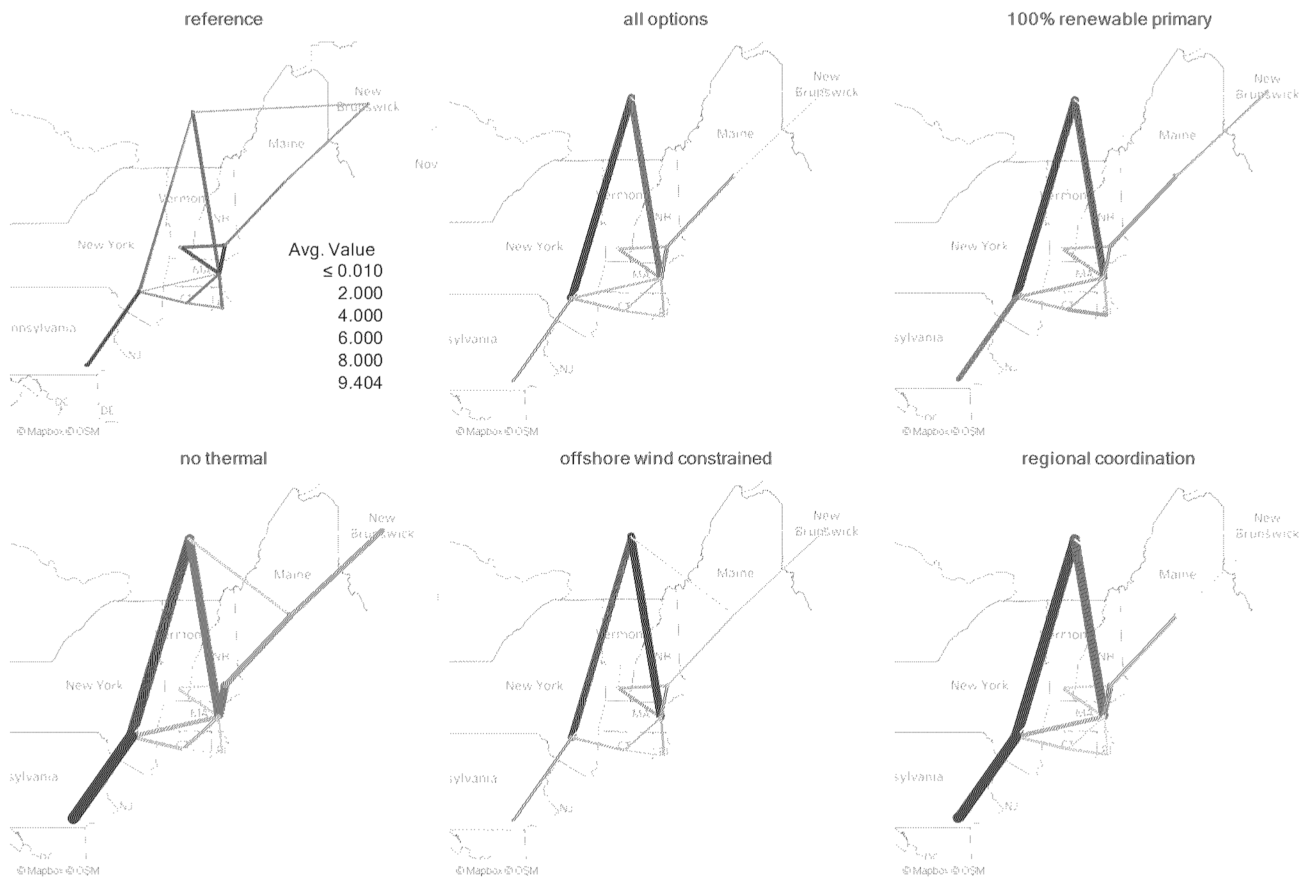


Figure 58 Massachusetts energy storage state of charge at the end of each day in 2050 for the No Thermal pathway.

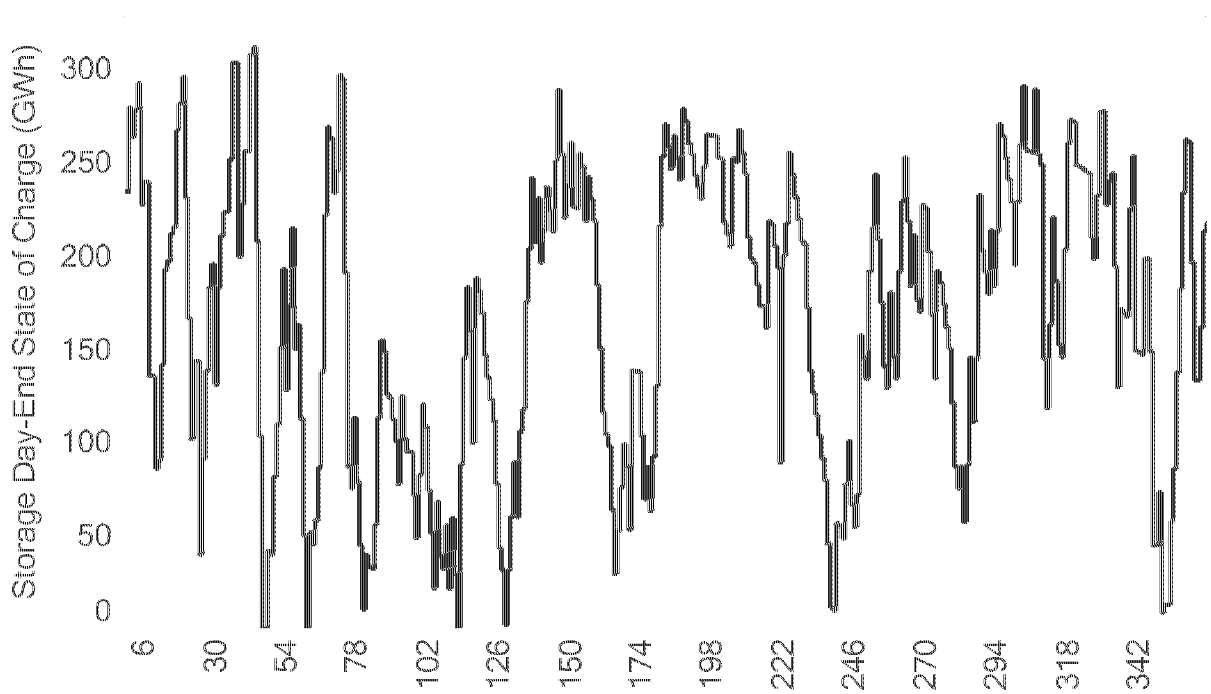
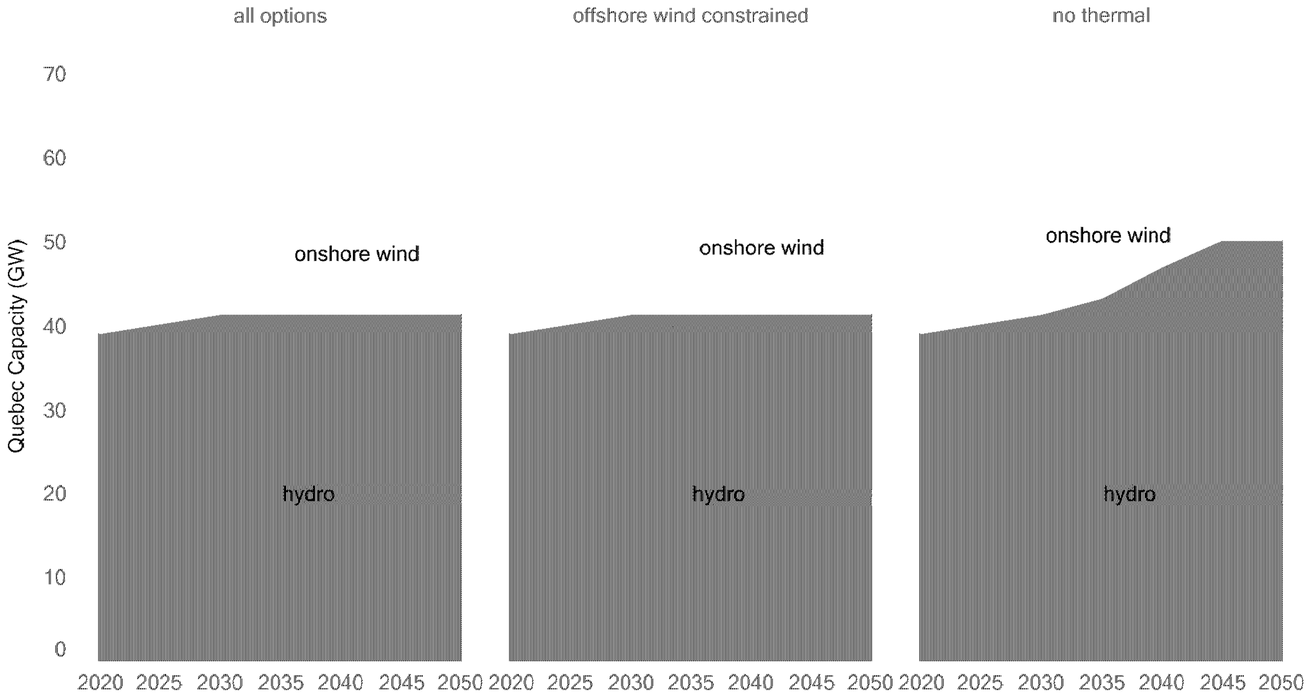


Figure 59 Installed capacity[92] in Quebec across between the All Options, Offshore Wind Constrained, and No Thermal pathways. The No Thermal pathway shows new hydro economically competitive against onshore wind in Canada due to the value of dispatch flexibility after all gas generation in the region is retired. In all other pathways, onshore wind is selected before new hydro. The increase in hydro capacity between 2020 and 2030 in all pathways represents planned additions.



[92] Because a share of Hydro Quebec production typically is exported to Ontario but not represented in the study zones, starting hydro capacity was derated to account for this energy. Ontario exports were assumed to remain constant.

Figure 60 All Options pathway daily energy operations for Quebec. Net transmission flow on the load-side (right) represents net daily exports. Imports are shown on the generation-side (left). Day-to-day variability in hydro production increases in future years to balance renewables regionally and warrants hydrological study.

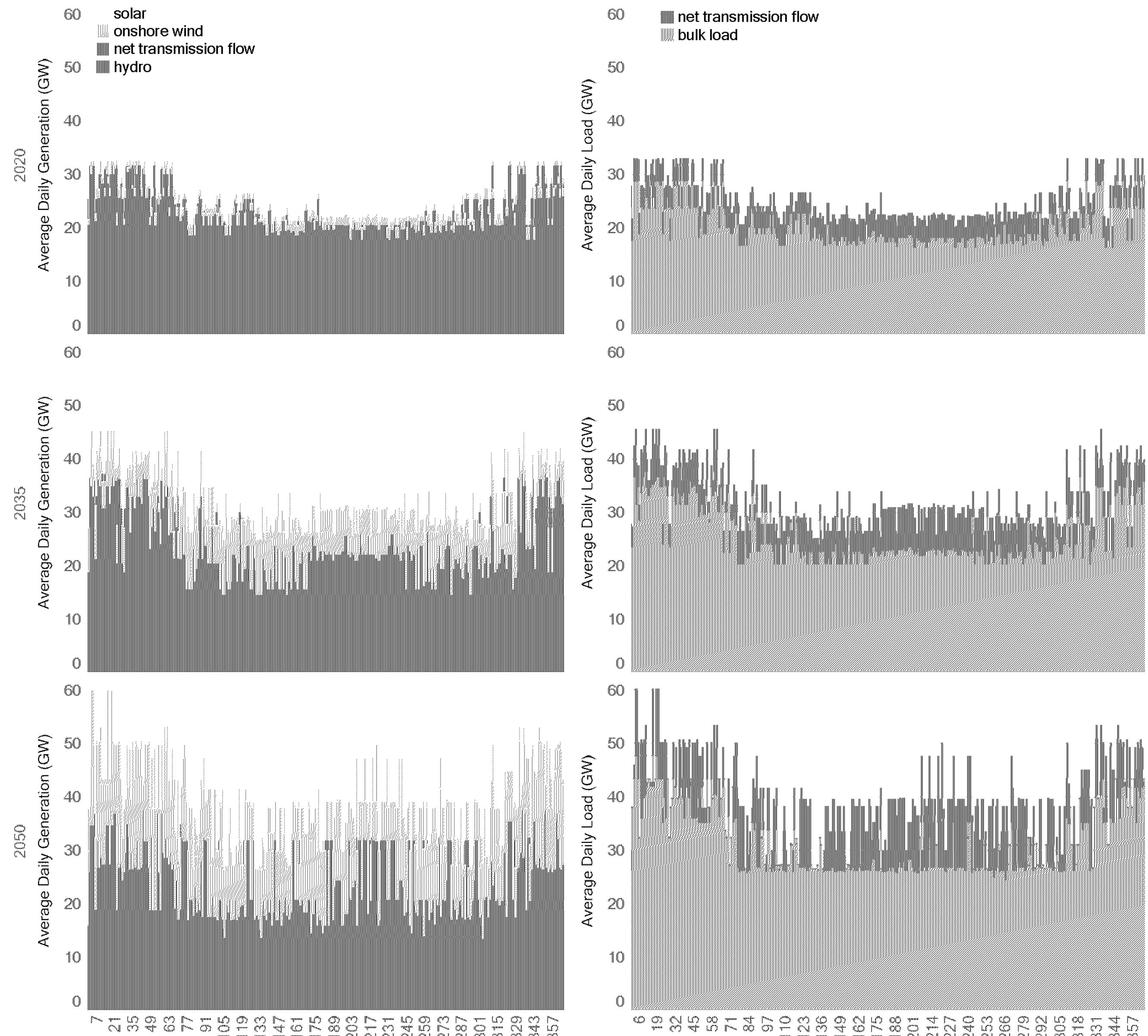


Figure 61 ISO-NE dispatchable or firm electricity capacity in 2050 across pathways. Storage is dispatchable, but not firm due to duration limits, whereas nuclear is firm, but assumed not to be dispatchable.

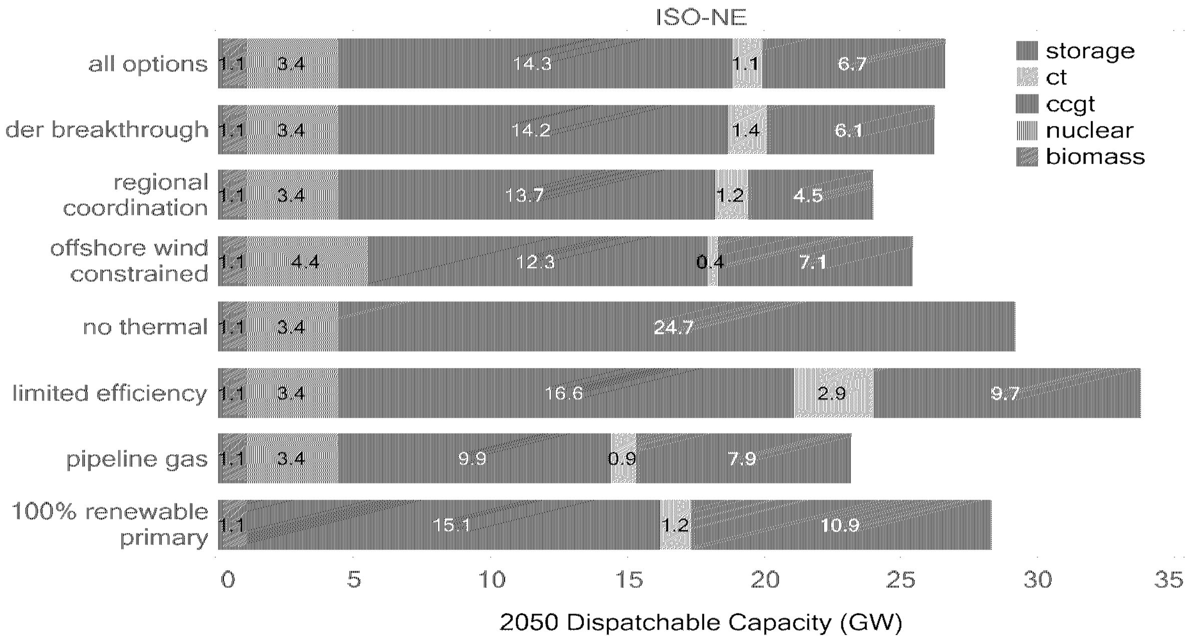


Figure 62 Massachusetts net energy system cost compared to the All Options pathway and broken out by final energy demand type. Costs above the x-axis represent incremental costs above All Options. Costs below the x-axis represent savings compared to All Options. The labeled black circles show the total net cost after summing each component. Pathways are ordered from lowest to highest cost in 2050. For context, three billion dollars is approximately half a percent of the current gross state product.

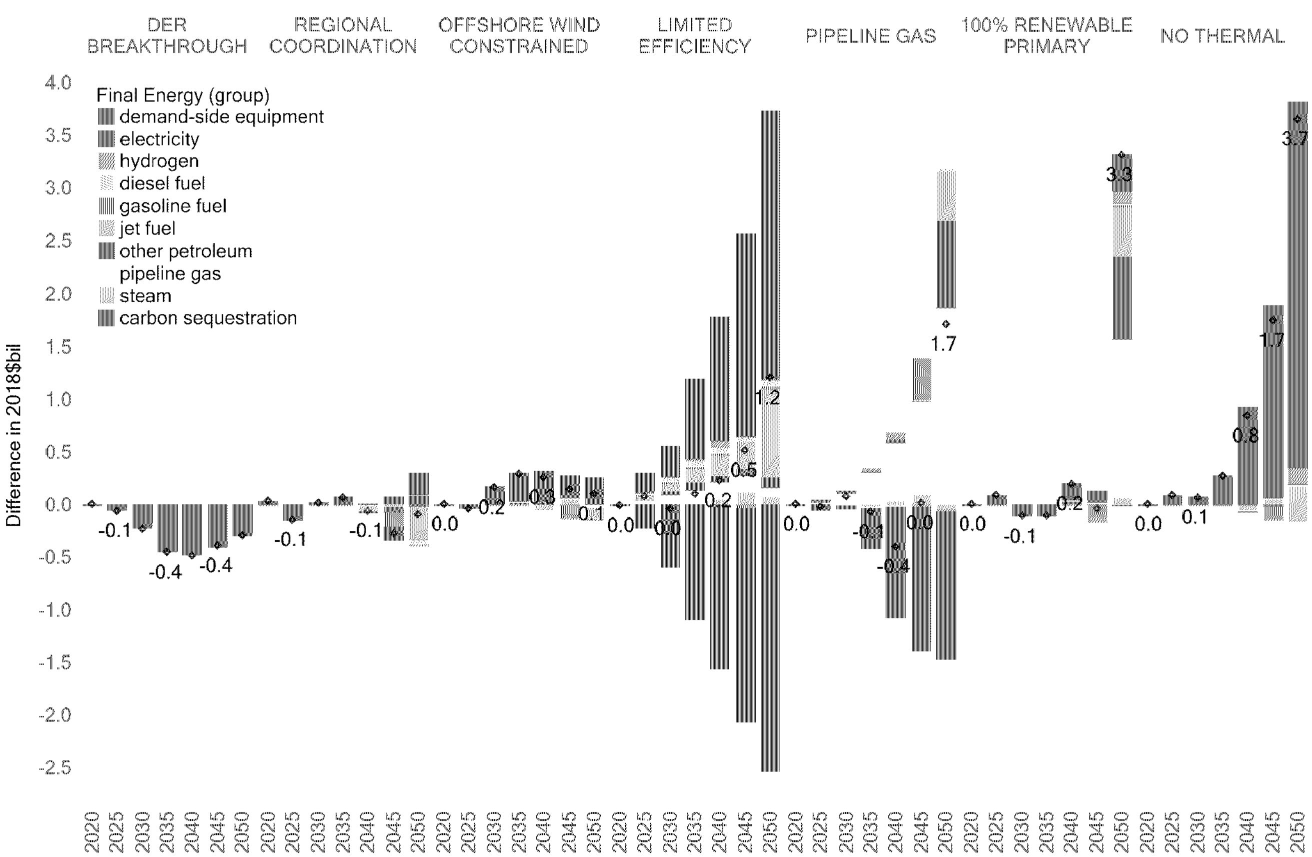


Table 23 Gross Massachusetts energy system cost (2018$B) by category in 2050 for each pathway

Cost Group	REFERENCE	ALL OPTIONS	100% RENEWABLE	DER BREAKTHRO	LIMITED EFFICIENCY	NO THERMAL	OFFSHORE WIND	PIPELINE GAS	REGIONAL COORDINATI
DEMAND-SIDE COSTS	0	4.21	4.21	4.21	1.68	4.21	4.21	4.15	4.21
ELECTRICITY STORAGE	0.16	0.25	0.37	0.21	0.33	2.31	0.3	0.3	0.17
ELECTRICITY DISTRIBUTION	3.29	5.06	5.06	4.7	5.96	5.06	5.06	4.48	5.06
ELECTRICITY TRANSMISSION	1.71	3.42	3.42	2.91	3.96	4.17	3.38	3.22	3.48
GAS PIPELINES	2.64	1.53	1.52	1.53	1.58	1.53	1.52	1.89	1.52
GAS POWER PLANTS	0.18	0.17	0.16	0.17	0.19	0.07	0.16	0.13	0.17
IN-STATE FUELS PRODUCTION	0.24	0.54	1.29	0.53	0.5	0.53	0.45	0.6	0.29
BIOMASS POWER PLANTS	0.31	0.07	0.06	0.07	0.06	0.1	0.06	0.05	0.07
GROUND-MOUNTED SOLAR	0.05	1.18	1.21	0.66	1.31	2.79	1.24	1.12	0.95
ROOFTOP SOLAR	0.79	0.79	0.79	1.9	0.79	0.79	0.79	0.79	0.79
OFFSHORE WIND	1.03	2.46	2.41	2.53	3.21	2.1	1.95	2.25	2.41
HYDRO PURCHASES	0.29	0.74	0.75	0.7	0.83	0.59	1.03	0.58	0.96
ZERO CARBON LIQUID IMPORTS	0.01	1.24	3.74	1.24	2.53	0.85	1.33	3.69	0.98
ZERO CARBON GAS IMPORTS	0.01	0.11	1.46	0.11	0.17	0.1	0.32	1.03	0.13
NATURAL GAS	1.8	0.19	0	0.19	0.23	0.15	0.18	0.48	0.18
OIL PRODUCTS	9.13	1.09	0	1.08	0.94	1.25	1.1	0.05	1.52
OTHER	0.71	0.85	0.73	0.86	0.85	0.96	0.92	0.8	0.82

Figure 63 2050 electrolysis capacity within each ISO-NE state compared between pathways

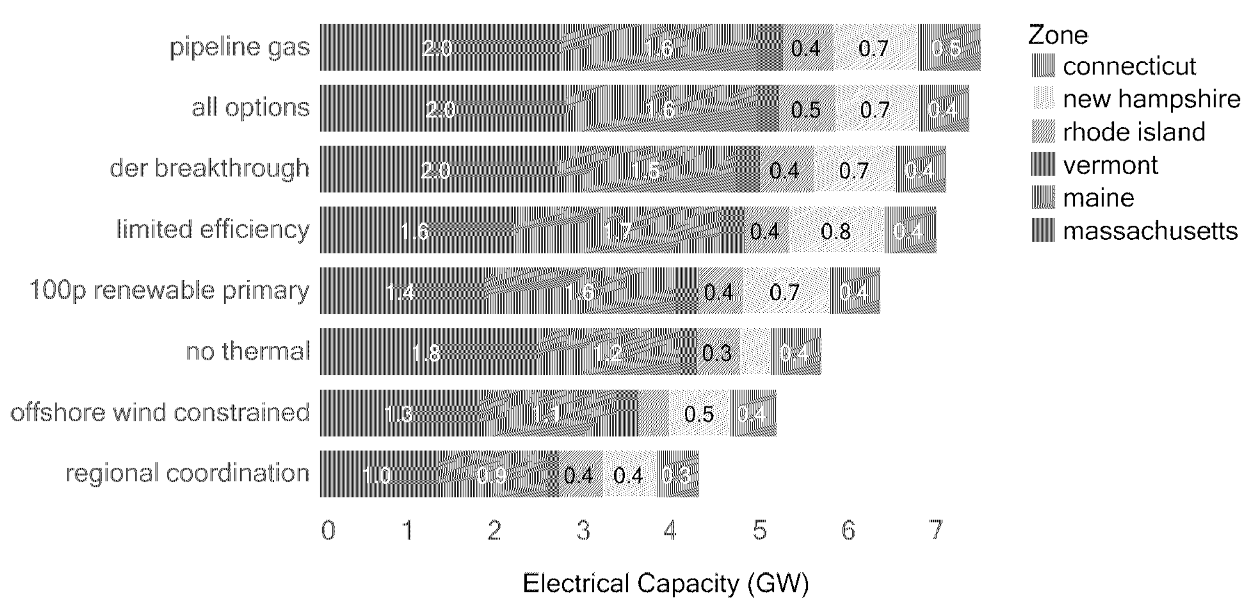


Figure 64 Four pillars of a net-zero energy system illustrated for the Pipeline Gas pathway. Despite lower building electrification than in other pathways, the percent of final energy supplied by electricity still more than doubles as a function of transportation electrification.

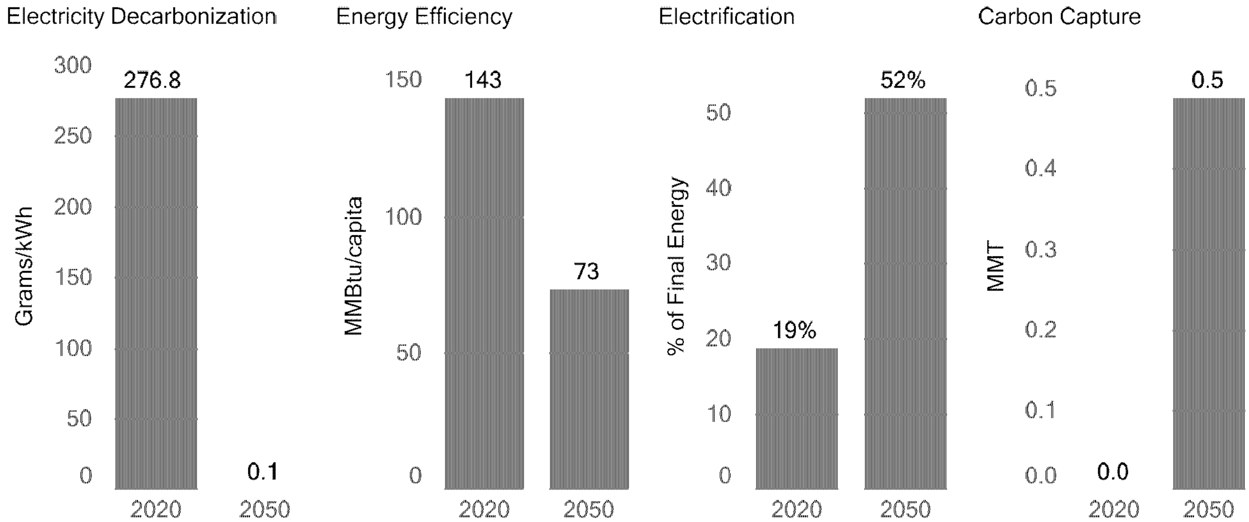
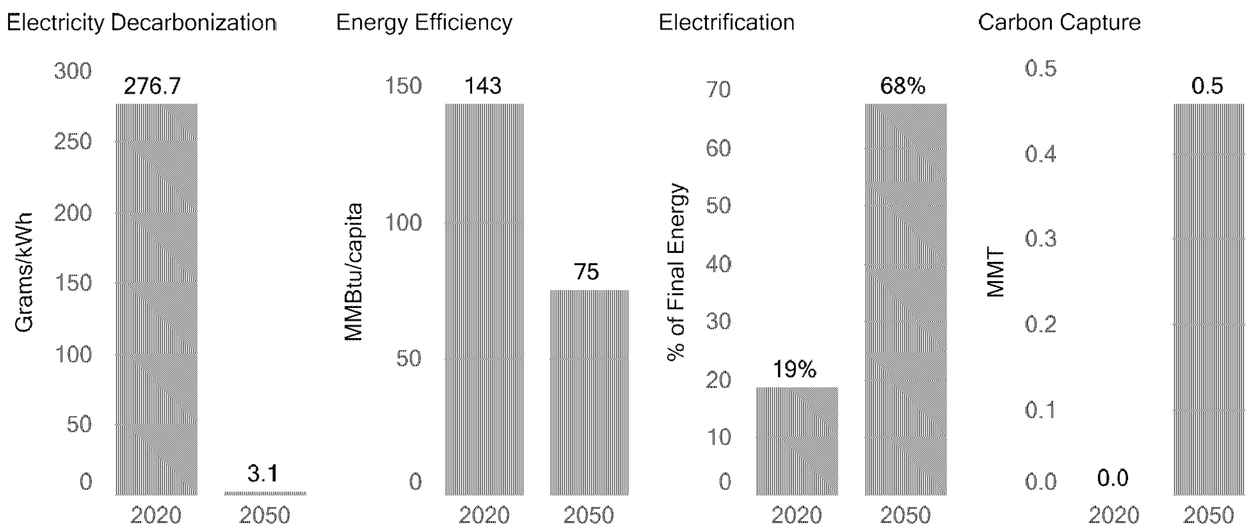


Figure 65 Four pillars of a net-zero energy system illustrated for the Limited Efficiency pathway. The efficiency of final energy consumption still increases significantly between 2020 and 2050 due to the final efficiency improvements from heat pumps and electric drivetrains.



9 Appendix 3: Detailed model methods

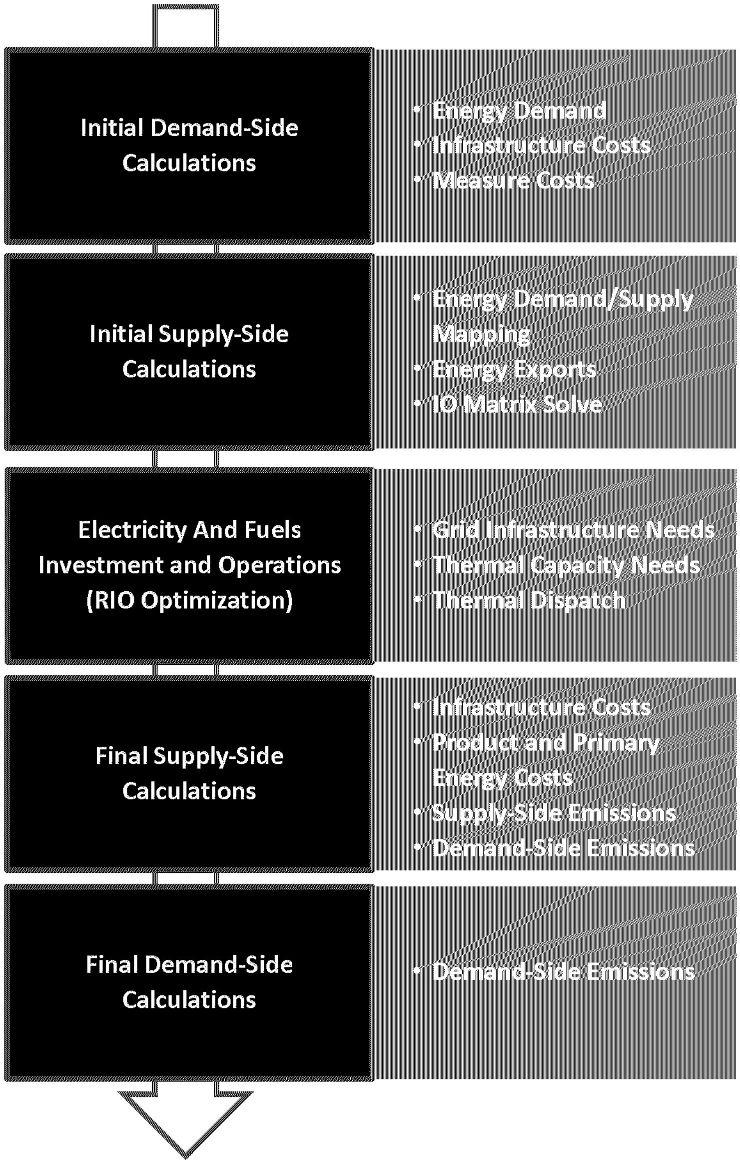
9.1 EnergyPATHWAYS

9.1.1 Model Structure

The EnergyPATHWAYS model is a comprehensive energy accounting and analysis framework specifically designed to examine large-scale energy system transformations. It accounts for the costs and emissions associated with producing, transforming, delivering, and consuming energy in an economy. It has strengths in infrastructure accounting and electricity operations that separate it from models of similar types. It is used, as it has been in this analysis, to calculate the effects of energy system decisions on future infrastructure, emissions, and costs to energy consumers and the economy more broadly.

EnergyPATHWAYS projects energy demand and costs in subsectors based on explicit user-decisions about technology adoption (e.g., electric vehicle adoption) and activity levels (e.g., reduced VMTs). These projections of energy demand across energy carriers are then sent to the supply-side of the model. In combination with RIO, the supply-side of the model calculates upstream energy flows, primary energy usage, infrastructure requirements, emissions, and costs of supplying energy. These supply-side outputs are then combined with the demand-side outputs to calculate the total energy flows, emissions, and costs of the modeled energy system.

Figure 66 shows the basic calculation steps for EnergyPATHWAYS and the outputs from each step.



The sections below describe the EnergyPATHWAYS demand-side, supply-side, infrastructure, emissions, and cost calculation methods in detail.

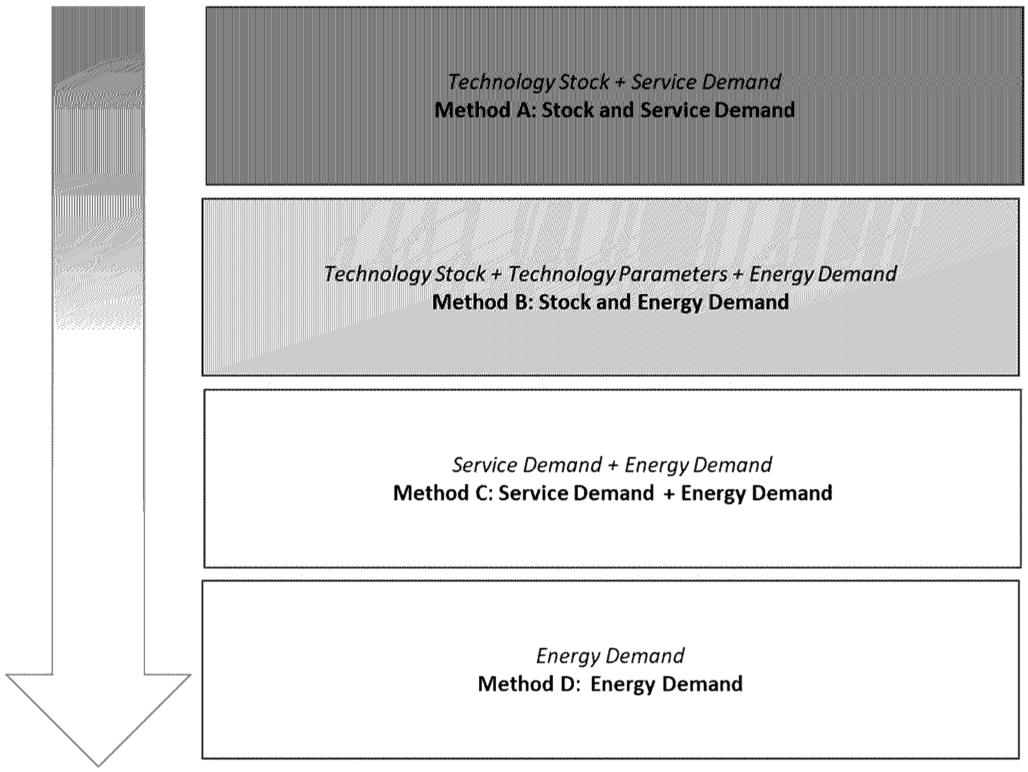
9.1.2 Subsectors

Subsectors represent separately modeled units of demand for energy services. These are often referred to as end-uses in other modeling frameworks. EnergyPATHWAYS is flexible in the configuration of subsectors, and methods used in each subsector depending on data availability. The high level of detail in subsectors in the EnergyPATHWAYS U.S. database is enabled by the availability of numerous high-quality data sources for the U.S. energy economy. Below we describe the calculations used for individual subsectors on the demand-side. Total demand is simply the summation of these calculations for all subsectors.

9.1.3 Energy Demand Projection

Data availability determines subsector granularity and informs the methods used in each subsector. The flow diagram below represents the decision matrix used to determine the methods – named A, B, C, D – used to model an individual energy demand subsector (Figure 64). The arrow downward indicates a progression from most-preferred (A) to least-preferred (D) methodology for modeling a subsector. The preferred methods allow for more explicit measures and better accounting of costs and energy impacts. Each method for projecting energy demand is described below.

Figure 67 Methods for projecting energy demand



9.1.3.1 Method A: Stock and Service Demand

This method is the most explicit representation of energy demand possible in the EnergyPATHWAYS framework. It has a high data requirement; many end-uses are not homogenous enough to represent with technology stocks and others do not have measurements of energy service demand. When the data requirements are met, EnergyPATHWAYS uses the following formula to calculate energy demand from a subsector.

Equation 1

$$E_{ycr} = \sum_{v \in V} \sum_{t=T} U_{yvtcr} * f_{vtc} * d_{yr} * (1 - R_{yrc})$$

Where

E = Energy demand in year y of energy carrier c in region r

U_{yvtcr} = Normalized share of service demand in year y of vintage v of technology t for energy carrier c in region r

f_{vtc} = Efficiency (energy/service) of vintage v of technology t using energy carrier c

d_{yr} = Total service demand input aggregated for year y in region r

R_{yrc} = Unitized service demand reductions for year y in region r for energy carrier c. Service demand reductions are calculated from input service demand measures, which change the baseline energy service demand levels.

9.1.3.1.1 *Service Demand Share (U)*

The normalized share of service demand (U) is calculated as a function of the technology stock (S), service demand modifiers (M), and energy carrier utility factors (C). Below is the decomposition of *U* into its component parts of *S* and *M and C.*

Equation 2

$$U_{yvtr} = \frac{S_{yvtr} * M_{yvtr} * C_{tc}}{\sum_{v \in V} \sum_{t \in T} S_{yvtr} * M_{yvtr}}$$

Where

S_{yvtr} = Technology stock in year y of vintage v of technology t in region r

M_{yvtr} = Service demand modifier in year y for vintage v for vintage t in region r

C_{tc} = Utility factor for energy carrier c for technology t

The calculation of these factors is detailed in the sections below

9.1.3.1.2 *Technology Stock (S)*

The composition of the technology stock is governed by stock-rollover mechanics in the model, technology inputs (lifetime parameters, the distribution and pattern of technology retirements), initial technology stock states, and the application of sales share or stock measures. The section below describes the ways in which these model variables can affect the eventual calculation of technology share.

9.1.3.1.3 *Initial Stock*

The model uses an initial representation of the technology stock to project forward. This usually represents a single-year stock representation based on customer survey data (e.g. the U.S. Commercial Building Energy Consumption Survey data informs 2012 technology stock estimates) but can also be "specified" into the future, where the composition of the stock is determined exogenously. At the end of this initial stock specification, the model uses technology parameters and rollover mechanics to determine stock compositions by year.

9.1.3.1.3.1 Stock Decay and Replacement

EnergyPATHWAYS allows for technology stocks to decay using linear representations or Weibull distributions, which are typical functions used to represent technology reliability and failure rates. These parameters are governed by a combination of technology lifetime parameters. Technology lifetimes can be entered as minimum and maximum lifetimes or as an average lifetime with a variance.

After the conclusion of the initial stock specification period, the model decays existing stock based on the age of the stock, technology lifetimes, and specified decay functions. This stock decay in a year (y) must be replaced with technologies of vintage (v) *v = y*. The share of replacements in vintage v is equal to the share of replacements unless this default is overridden with exogenously specified sales share or stock measures. This share of sales is also used to inform the share of technologies deployed to meet any stock growth.

9.1.3.1.3.2 Sales Share Measures

Sales share measures override the pattern of technologies replacing themselves in the stock rollover.
An example of a sales share measure is shown below for two technologies – A and B - that are represented equally in the initial stock and have the same decay parameters. EnergyPATHWAYS applies a sales share measure in the year 2020 that requires 80% of new sales in 2020 to be technology A and 20% to be technology B. The first equation shows the calculation in the absence of this sales share measure. The second shows the stock rollover governed with the new sales share measure.

S = Stock
D = Stock decay

G = Year on year stock growth

R = Stock decay replacement

H = User specified share of sales for each technology

N = New Sales

a = Technology A

b = Technology B

Before Measure (i.e. Baseline)

S_{2019} = 100

S_{a2019} = 50

S_{b2019} = 50

D_{2020} = 10

D_{a2020} = 5

D_{b2020} = 5

S_{2020} = 110

$G_{2020} = S_{2020} - S_{2019} = 110 - 100 = 10$

R_{a2020} = D_{a2020} = 5

R_{b2020} = D_{b2020} = 5

$G_{a2020} = \frac{D_{a2020}}{D_{2020}} * G_{2020}$ = 5/10 * 10 =5

$G_{b2020} = \frac{D_{b2020}}{D_{2020}} * G_{2020}$ = 5/10 * 10 = 5

$N_{a2020} = R_{a2020} + G_{a2020}$ = 5 + 5 = 10

$N_{b2020} = R_{b2020} + G_{b2020}$ = 5 + 5 = 10

$S_{a2020} = S_{a2019} + D_{a2020} + N_{a2020}$ = 50 – 5 + 10 = 55

$S_{b2020} = S_{b2019} + D_{b2020} + N_{b2020}$ = 50 – 5 + 10 = 55

After Sales Share Measure

S_{2019} = 100

S_{a2019} = 50

S_{b2019} = 50

D_{2020} = 10

D_{a2020} = 5

D_{b2020} = 5

S_{2020} = 110

$G_{2020} = S_{2020} - S_{2019} = 110 - 100 = 10$

$R_{a2020} = D_{2020} * H_{a2020}$ = 10 * .8 = 8

$R_{b2020} = D_{2020} * H_{b2020}$ = 10 * .2 = 2

$G_{a2020} = G_{2020} * H_{a2020}$ = 10 * .8 = 8

$G_{b2020} = G_{2020} * H_{b2020}$ = 10 * .2 = 2

$N_{a2020} = R_{a2020} + G_{a2020}$ = 8 + 8 = 16

$N_{b2020} = R_{b2020} + G_{b2020}$ = 2 + 2 = 4

$S_{a2020} = S_{a2019} + D_{a2020} + N_{a2020}$ = 50 – 5 + 16 = 61

$S_{b2020} = S_{b2019} + D_{b2020} + N_{b2020}$ = 50 – 5 + 4 = 49

This shows a very basic example of the role that sales share measures play to influence the stock of technology. In the context of energy demand, these technologies can use different energy carriers (i.e. gasoline internal combustion engine vehicles to electric vehicles) and/or have different efficiency characteristics.

Though not shown in the above example, the stock is tracked on a vintaged basis, so decay of technology A in 2020 in the above example would be decay in 2020 of all vintages before 2020. In the years immediately following the deployment of vintage cohort, there is very little technology retirement given the shape of the decay functions. As a vintage approaches the end of its anticipated useful life, however, retirement accelerates.

9.1.3.1.4 *Service Demand Modifier (M)*

Many energy models use stock technology share as a proxy for service demand share. This makes the implicit assumption that all technologies of all vintage in a stock are used equally. This assumption obfuscates some key dynamics that influence the pace and nature of energy system transformation. For example, new heavy-duty vehicles are used heavily at the beginning of their useful life but are sold to owners who operate them for reduced duty-cycles later in their lifecycles. This means that electrification of this fleet would accelerate the rollover of electrified miles faster than it would accelerate the rollover of the trucks themselves. Similar dynamics are at play in other vehicle subsectors. In subsectors like residential space heating, the distribution of current technology stock is correlated with its utilization. Even within the same region, with the same climactic conditions, the choice of heating technology informs its usage. Homes that have baseboard electric heating, for example, are often seasonal homes with limited heating loads.

EnergyPATHWAYS has two methods for determining the discrepancy between stock shares and service demand shares. First, technologies can have the input of a *service demand modifier*. This is used as an adjustment between stock share and service demand share.

Using the example stock of Technology, A and B, the formula below shows the impact of service demand modifier on the service demand share.

S = Stock
x = Stock ratio
M = service demand modifier
U = service demand allocator

$$S_{2019} = 100$$
$$S_{a2019} = 50$$
$$S_{a2020} = 50$$
$$x_{a2019} = \frac{S_{a2019}}{S_{2019}} = \frac{50}{100} = .5$$
$$x_{b2019} = \frac{S_{b2019}}{S_{2019}} = \frac{50}{100} = .5$$
$$M_{a2019} = 2$$
$$M_{b2019} = 1$$
$$U_{a2019} = \frac{S_{a2019} * M_{a2019}}{\sum_{t=a..b} S_{t2019} * M_{t2019}} = \frac{50*2}{150} = .667$$
$$U_{b2019} = \frac{S_{b2019} * M_{b2019}}{\sum_{t=T} S_{t2019} * M_{t2019}} = \frac{50*1}{150} = .333$$

When service demand modifiers aren't entered for individual technologies, they can potentially still be calculated using input data. For example, if the service demand input data is entered with the index of t, the model calculates service demand modifiers by dividing stock and service demand inputs.

Equation 3

$M_{tyr} = \frac{s_{tyr}}{d_{tyr}}$

Where

M_{ty} = Service demand modifier for technology t in year y in region r

s_{tyr} = Stock input data for technology t in year y in region r

d_{tyr} = Energy demand input data for technology t in year y in region r

9.1.3.1.4.1 Energy Carrier Utility Factors (C)

Energy carrier utility factors are technology inputs that allocate a share of the technology's service demand to energy carriers. The model currently supports up to two energy carriers per technology. This allows EnergyPATHWAYS to support analysis of dual-fuel technologies, like plug-in-hybrid electric vehicles. The input structure is defined as a primary energy carrier with a utility factor (0 – 1) and a secondary energy carrier that has a utility factor of 1 – the primary utility factor.

9.1.3.1.5 *Method B: Stock and Energy Demand*

Method B is like Method A in almost all its components except for the calculation of service demand. In Method A, service demand is an input. In Method B, the energy demand of a subsector is used as a substitute input for service demand. From this input, EnergyPATHWAYS takes the additional step of deriving service demand, based on stock and technology inputs.

Equation 4

$$E_{ycr} = \sum_{v \in V} \sum_{t=T} U_{yvtcr} * f_{vtc} * D_{yr} * (1 - R_{yrc})$$

Where

E = Energy demand in year *y* of energy carrier *c* in region *r*

U = Normalized share of service demand in year *y* of vintage *v* of technology *t* for energy carrier *c* in region *r*

f = Efficiency (energy/service) of vintage v of technology t using energy carrier c

D = Total service demand calculated for year *y* in region *r*

R_{yrc} = Unitized service demand reductions for year *y* in region *r* for energy carrier *c*

9.1.3.1.5.1 Total Service Demand (D)

Total service demand is calculated using stock shares, technology efficiency inputs, and energy demand inputs. The intent of this step is to derive a service demand term (D) that allows us to use the same calculation framework as Method A.

Equation 5

$$D_{yr} = \sum_{v \in V} \sum_{c \in C} \sum_{t=T} U_{yvtcr} * f_{vtc} * e_{ycr}$$

Where

D_{yr} = Total service demand in year y in region r

f_{vtc} = Efficiency (energy/service) of vintage v of technology t using energy carrier c

e_{ycr} = Input energy data in year y of carrier c in region r

9.1.3.1.6 *Method C: Service and Service Efficiency*

Method C is used when EnergyPATHWAYS does not have sufficient input data, either at the technology level or the stock level, to parameterize a stock rollover. Instead EnergyPATHWAYS replaces the stock terms in the energy demand calculation with a service efficiency term (j). This is an exogenous input that substitutes for the stock rollover dynamics and outputs in the model. Within this study, no subsectors use Method C, but the description is included here for completeness.

Equation 6

$$E_{ycr} = j_{ycr} * d_{yr} * R_{yrc} - O_{yrc}$$

where

E_{ycr} = Energy demand in year y for energy carrier c in region r

j_{ycr} = Service efficiency (energy/service) of subsector in year y for energy carrier c in region r

d_{yr} = Input service demand for year y in region r

R_{yrc} = Unitized service demand multiplier for year y in region r for energy carrier c

O_{yrc} = Energy efficiency savings in year y in region r for energy carrier c

9.1.3.1.6.1 Energy Efficiency Savings (O)

Energy efficiency savings are a result of exogenously specified energy efficiency measures in the model. These take the form of prescribed levels of energy savings that are netted off the baseline projection of energy usage.

9.1.3.1.7 *Method D: Energy Demand*

The final method is simply the use of an exogenous specification of energy demand. This is used for subsectors where there is neither the data necessary to populate a stock rollover nor any data available to decompose energy use from its underlying service demand.

Equation 7

$$E_{ycr} = e_{ycr} - O_{yrc}$$

Where

E_{ycr} = Energy demand in year y for energy carrier c in region r

e_{ycr} = Input baseline energy demand in year y for energy carrier c in region r

O_{yrc} = Energy efficiency savings in year y in region r for energy carrier c

9.1.3.1.8 *Demand-Side Costs*

Cost calculations for the demand-side are separable into technology stock costs and measure costs (energy efficiency and service demand measures).

9.1.3.1.9 *Technology Stock Costs*

EnergyPATHWAYS uses vintaged technology cost characteristics as well as the calculated stock rollover to calculate the total costs associated with technology used to provide energy services.[93]

$$C_{yr}^{stk} = C_{yr}^{cap} + C_{yr}^{ins} + C_{yr}^{fs} + C_{yr}^{fom}$$

Where

C_{yr}^{stk} = Total levelized stock costs in year y in region r

C_{yr}^{cap} = Total levelized capital costs in year y in region r

[93] Levelized costs are the principal cost metric reported, but the model also calculates annual costs (i.e. the cost in 2020 of all technology sold). Supply-side technology costs are included in the accompanying Excel workbook to this technical appendix.

C_{yr}^{ins} = Total levelized installation costs in year y in region r

C_{yr}^{fs} = Total levelized fuel switching costs in year y in region r

C_{yr}^{fom} = Total fixed operations and maintenance costs in year y in region r

9.1.3.1.9.1 Technology Stock Capital Costs

The model uses information from the physical stock rollover used to project energy demand, with a few modifications. First, the model uses a different estimate of technology life. The financial equivalent of the physical "decay" of the technology stock is the depreciation of the asset. The asset is depreciated over the "book life," which doesn't change, regardless of whether the physical asset has retired.

To provide a concrete example of this, a 2020 technology vintage with a book life of 15 years is maintained in the financial stock in its entirety for the 15 years before it is financially "retired" in 2035. This financial stock estimate, in addition to being used in the capital costs calculation, is used for calculating installation costs and fuel switching costs.

Equation 8

$$C_{yr}^{cap} = \sum_{v \in V} \sum_{t \in T} S_{tvyr}^{fin} * W_{tvr}^{cap}$$

Where

C_{yr}^{cap} = Total levelized technology costs in year y in region r

W_{tvr}^{cap} = Levelized capital costs for technology t for vintage v in region r

S_{tvyr}^{fin} = Financial stock of technology t and vintage v in year y in region r

EnergyPATHWAYS primarily uses this separate financial accounting so that EnergyPATHWAYS accurately account for the costs of early-retirement of technology. There is no way to financially early-retire an asset, so physical early retirement increases overall costs (by increasing the overall financial stock).

9.1.3.1.9.2 Levelized Capital Costs (W)

EnergyPATHWAYS levelizes technology costs over the mean of their projected useful lives (referred to as book life). This is either the input mean lifetime parameter or the arithmetic mean of the technology's max and min lifetimes. EnergyPATHWAYS additionally assesses a cost of capital on this levelization of the technology's upfront costs. While this may seem an unsuitable assumption for technologies that could be considered "out-of-pocket" purchases, EnergyPATHWAYS assumes that all consumer purchases are made using backstop financing options. This is the implicit assumption that if "out-of-pocket" purchases were reduced, the amount needed to be financed on larger purchases like vehicles and homes could be reduced in-kind.

$$W_{tvr}^{cap} = \frac{d_t * z_{tvr}^{cap} * (1 + d_t)^{l_t^{book}}}{(1 + d_t)^{l^{book}} - 1}$$

Where

W_{tvr}^{cap} = Levelized capital costs for technology t for vintage v in region r

d_t = Discount rate of technology t

z_{tvr}^{cap} = Capital costs of technology t in vintage v in region r

l_t^{book}= Book life of technology t

9.1.3.1.9.3 Technology Stock Installation Costs

Installation costs represent costs incurred when putting a technology into service. The methodology for calculating these is the same as that used to calculate capital costs. These are levelized in a similar manner.

9.1.3.1.9.4 Technology Stock Fuel Switching Costs

Fuel switching costs represent costs incurred for a technology only when switching from a technology with a different primary energy carrier. This input is used for technologies like gas furnaces that may need additional gas piping if they are being placed in service in a household that had a diesel furnace. Calculating these costs requires the additional step of determining the number of equipment sales in a given year associated with switching fuels.

9.1.3.1.10 *Technology Stock Fixed Operations and Maintenance Costs*

Fixed operations and maintenance (O&M) costs are the only stock costs that utilize physical and not financial representations of technology stock. This is because O&M costs are assessed annually and are only incurred on technologies that remain in service. If equipment has been retired, then it no longer has ongoing O&M costs.

$$C_{yr}^{fom} = \sum_{v \in V} \sum_{t \in T} S_{tyvr} * W_{tvr}^{fom}$$

Where

S_{tyvr}= Technology stock of technology t in year y of vintage v in region r

W_{tvr}^{fom} = Fixed O&M costs for technology t for vintage v in region r

9.1.3.1.11 *Measure Costs*

Measure costs are assessed for interventions either at the service demand (service demand measures) or energy demand levels (energy efficiency measures). While these measures are abstracted from technology-level inputs, EnergyPATHWAYS uses a similar methodology for these measures as for technology stock costs. EnergyPATHWAYS uses measure savings to create “stocks” of energy efficiency or service demand savings. These measure stocks are vintaged like technology stocks and EnergyPATHWAYS use analogous inputs like capital costs and useful lives to calculate measure costs.

9.1.3.1.12 *Energy Efficiency Measure Costs*

Energy efficiency costs are costs associated the reduction of energy demand. These are representative of incremental equipment costs or costs associated with non-technology interventions like behavioral energy efficiency.

Equation 9

$$C_{yr}^{ee} = \sum_{v \in V} \sum_{m \in M} S_{mvyr}^{ee} * W_{mvr}^{ee}$$

Where

C_{yr}^{ee} = Total energy efficiency measure costs

S_{mvyr}^{sd} = Financial stock of energy demand reductions from measure m of vintage v in year y in region r

W_{mvr}^{ee} = Levelized per-unit energy efficiency costs

9.1.4 EnergyPATHWAYS supply-side

9.1.4.1 Supply Nodes

Supply nodes represent the fundamental unit of analysis on the supply-side and are analogous to subsectors on the demand-side. We will primarily describe the calculations for individual supply nodes in this document, but assessing the total costs and emissions from the supply-side is just the summation of all supply nodes for a year and region.

9.1.4.2 I/O Matrix

There is one principal difference between supply nodes and subsectors that explains the divergent approaches taken for calculating them; energy flows through supply nodes must be solved concurrently due to a number of dependencies between nodes. As an example, it is not possible to know the flows through the gas transmission pipeline node without knowing the energy flow through gas power plant nodes. This tenet requires a fundamentally different supply-side structure. To solve the supply-side, EnergyPATHWAYS leverages techniques from economic modeling by arranging supply nodes in an input-output matrix, where coefficients of a node represent units of other supply nodes required to produce the output product of that node. Consider a simplified representation of upstream energy supply with four supply nodes:

a. Electric Grid

b. Gas Power Plant

c. Gas Transmission Pipeline

d. Primary Natural Gas

This is a system that only delivers final energy to the demand-side in the form of electricity from the electric grid. It also has the following characteristics:

1. The gas transmission pipeline has a loss factor of 2% from leakage. It also uses grid electricity to power compressor stations and requires .05 units of grid electricity for every unit of delivered gas.

2. The gas power plant has a heat rate of 8530 Btu/kWh, which means that it requires 2.5 (8530 Btu/kWh/3412 Btu/kWh) units of gas from the transmission pipeline for every unit of electricity generation.

3. The electricity grid has a loss factor of 5%, so it needs 1.05 units of electricity generation to deliver 1 unit of electricity to its terminus.

The I/O matrix for this system is shown in tabular form in Table 20 as well as in matrix form in the equation below.

Table 24. Tabular I/O Matrix

	Natural Gas	Gas Transmission Pipeline	Gas Power Plant	Electric Grid
Natural Gas		1.02		
Gas Transmission Pipeline			2.5	
Gas Power Plant				1.05
Electric Grid		.05		

Equation 10

$$A = \begin{pmatrix} & 1.05 & & \\ & & 2.5 & \\ & & & 1.05 \\ & .05 & & \end{pmatrix}$$

With this I/O matrix, if we know the demand for energy from a node (supplied from the demand-side of the EnergyPATHWAYS model), we can calculate energy flows through every upstream supply node. To continue the example, if 100 units of electricity are demanded:

$$d = \begin{pmatrix} 0 \\ 0 \\ 0 \\ 100 \end{pmatrix}$$

We can calculate the energy flow through each node using the equation, which represents the inverted matrix multiplied by the demand term.

$$x = (I - A)^{-1} * d$$

This gives us the following result:

$$x = \begin{pmatrix} 308 \\ 302 \\ 121 \\ 115 \end{pmatrix}$$

Applied in EnergyPATHWAYS the I/O structure is much more complex than this simple example. Most of the supply-side calculations are focused on populating I/O coefficients and solving throughput through each node, which allows us to calculate infrastructure needs, costs, resource usage, and greenhouse gas emissions associated with energy supply

There are six distinct types of nodes that represent different components of the energy supply system. These will be examined individually in all of the supply-side calculation descriptions. The list below details some of their basic functionality

1. **Conversion Nodes –** Conversion nodes represent units of infrastructure specified at the technology level (i.e. gas combined cycle power plant) that have a primary purpose of converting the outputs of one supply node to the inputs of another supply node. Gas power plants in the above example are a conversion node, converting the output of the gas transmission pipeline to the inputs of the electric grid.
2. **Delivery Nodes –** Delivery nodes represent infrastructure specified at a non-technology level. The gas transmission pipeline is an example of a delivery node. A transmission pipeline system is the aggregation of miles of pipeline, hundreds of compressor stations, and storage facilities. We represent it as an aggregation of these components. The role of delivery nodes is to deliver the outputs of one supply node to a different physical location in the system required so that they can be used as inputs to another supply node. In the above example, gas transmission pipelines deliver natural gas from gas fields to gas power plants, which are not co-located with the resource. A full list of the delivery nodes in EnergyPATHWAYS is given in Table 21.
3. **Primary Nodes –** Primary nodes are used for energy accounting, but they generally represent the start of the energy supply chain. That is, absent some exceptions, their coefficients are generally zero.
4. **Product Nodes –** Product nodes are used to represent energy products where it is not possible to endogenously build up the costs and emissions back through to their primary energy source.
5. **Blend Nodes –** Blend nodes are non-physical control nodes in the energy supply chain. These are the locations in the energy system that we apply measures to change the relative inputs to other supply nodes. There are no blend nodes in the simplified example above, but an alternative energy supply system may add a biogas product node and place a blend node between the gas transmission pipeline and the primary natural gas node. This blend node would be used to control the relative inputs to the gas transmission pipeline (between natural gas and biogas).

6. **Electric Storage Nodes –** Electric storage nodes are nodes that provide a unique role in the electricity dispatch functionality of EnergyPATHWAYS, as discussed further below.

Table 25 EnergyPATHWAYS supply-side delivery nodes

EnergyPATHWAYS Delivery Nodes
Coal - Rail Delivery
Coal - End-Use Delivery
Diesel End-Use Delivery
Electricity Distribution Grid
Electricity Transmission Grid
Gas Distribution Pipeline
Gas Transmission Pipeline
Hydrogen Fueling Stations
Liquid Hydrogen Truck Delivery
LPG Feedstock Delivery
Lubricants Delivery
Motor Gasoline End-Use Delivery
Petrochemical Feedstock Delivery
Pipeline Gas Feedstock Delivery
Residual Fuel-Oil End-Use Delivery

9.1.4.3 Energy Flows

9.1.4.3.1 *Coefficient Determination (A – Matrix)*

The determination of coefficients is unique to supply-node types. For primary, product, and delivery nodes, these efficiencies are exogenously specified by year and region.

9.1.4.3.2 *Conversion Nodes*

Conversion node efficiencies are calculated as the weighted averages of the online technology stocks. We use both stock and capacity factor terms because we want the energy-weighted efficiency, not capacity-weighted.

Equation 11

$$X_{ynr} = \sum_{t \in T} \sum_{v \in V} \frac{S_{tvyr} * u_{tvyr}}{\sum_{t \in T} \sum_{v \in V} S_{tvyr} * u_{tvyr}} * f_{tvnr}$$

Where

X_{ynr} = Input coefficients in year y of node n in region r

S_{tvyr} = Technology stock of technology t in year of vintage v in year y in region r

u_{tvyr} = Utilization rate, or capacity factor, of technology t of vintage v in year y in region r

f_{vntr} = Input requirements (efficiency) of technology t of vintage v using node n in region r

9.1.4.3.3 *Energy Demands*

9.1.4.3.3.1 Demand Mapping

To help develop the (d) term in the matrix calculations described in section 9.1.4.2, EnergyPATHWAYS must map the demand for energy carriers calculated on the demand-side to specific supply-nodes. In the simplified energy system example, electricity as a final energy carrier, for example, maps to the Electric Grid supply node.

9.1.4.3.3.2 Energy Export Specifications

In addition to demand-side energy requirements, the energy supply system must also meet export demands, that is demand for energy products that aren't used to satisfy domestic energy service demands, but instead are sent to other countries. These products aren't ultimately consumed in the model, but their upstream impacts must still be accounted for. Within the Net-Zero America Study, these fossil fuel exports are gradually trended down along with petroleum consumption, which reduces up-stream emissions in the decarbonization scenarios.

9.1.4.3.3.3 Total Demand

Total demand is the sum of domestic energy demands from the demand-side of EnergyPATHWAYS as well as any specified energy exports.

Equation 12

$$D_{yrn} = D_{yrn}^{end} + D_{yrn}^{exp}$$

Where

D_{yrn} = Total energy demand in year y in region r for supply node n

D_{yrn}^{end} = Endogenous energy demand in year y in region r for supply node n

D_{yrn}^{exp} = Export energy demand in year y in region r for supply node n

This total demand term is then multiplied by the inverted coefficient matrix to determine energy flows through each node.

9.1.5 **Infrastructure Requirements**

Infrastructure is represented by delivery and conversion supply nodes. Infrastructure here refers to physical assets that produce or move energy to end-use applications. In delivery nodes, this infrastructure is represented at the aggregate node-level. In conversion nodes, infrastructure is represented in technology stocks similarly to stocks on the demand-side. The sections below detail the basic calculations used to determine the infrastructure capacity needs associated with energy flows through the supply node.

9.1.5.1 Delivery Nodes

The infrastructure capacity required is determined by Equation 13 below:

Equation 13

$$I_{yr} = \frac{E_{yr}}{u_{yr} * 8760}$$

Where

u_{yr}[94] = Utilization (capacity) factor in year y in region r

E_{yr} = Energy flow through node in year y in region r

h = Hours in a year, or 8760

9.1.5.2 Conversion Nodes

Conversion nodes are specified on a technology-basis, and a conversion node can contain multiple technologies to produce the energy flow required by the supply system. The operations of these nodes are analogous to the demand-side in terms of stock rollover mechanics, with sales shares and specified stock

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[94] Capacity factors of delivery nodes are exogenous inputs to the model except in the special cases of the Electricity Transmission Grid Node and the Electricity Distribution Grid node, where capacity factors are determined in the electricity dispatch.

measures determining the makeup of the total stock. The only difference is that the size of the total stock is determined by the demand for energy production for the supply node, which is different than on the demand-side, where the size of the total stock is an exogenous input.

The formula to determine the size of the total stock remains essentially the same as the one used to determine the size of the total delivery stock. However, the average capacity factor of the node is a calculated term determined by the weighted average capacity factor of the stock in the previous year:

Equation 14

$$U_{yr} = \frac{\sum_{t \in T} \sum_{v \in V} S_{tvy-1r} * u_{tvyr}}{\sum_{t \in T} \sum_{v \in V} S_{tvy-1r}}$$

Where

U_{yr} = Utilization (capacity) factor in year y in region r

S_{tvy-1r} = Technology stock of technology t in year of vintage v in year y-1 in region r

u_{tvyr} = Utilization rate, or capacity factor, of technology t of vintage v in year y in region r

9.1.6 Emissions

There are two categories of greenhouse gas emissions in the model. First, there are physical emissions. These are traditional emissions associated with the combustion of fuels, and they represent the greenhouse gas emissions embodied in a unit of energy. For example, natural gas has an emissions rate of 53.06 kG/MMBTU of consumption while coal has an emissions rate of 95.52 kG/MMBTU[95]. Physical emissions are accounted for on the supply-side in the supply nodes where fuels are consumed, which can occur in primary, product, delivery, and conversion nodes. Emissions, or consumption, coefficients, that is the units of fuel consumed can be a subset of energy coefficients. While the gas transmission pipeline may require 1.03 units of natural gas, it only consumes 0.03 units. Gas power plants, however, consume all 2.5 units of gas required. Equation 15 shows the calculation of physical emissions in a node:

Equation 15

$$G_{yr}^{phy} = \sum_{n \in N} X_{yrn}^{con} * E_{yr} * B_{yrn}^{phy}$$

Where

G_{yr}^{phy} = Physical greenhouse gas emissions in year y in region r

X_{yrn}^{con} = Consumption coefficients in year y in region r of node n

E_{yr}= Energy flow through node in year y in region r

B_{yrn}^{phy} = Emissions rates (emissions/energy) in year y in region r of input nodes n.

Emissions rates are either a function of a direct connection in the I/O matrix to a node with an emissions coefficient or they are "passed through" delivery nodes, which don't consume them. Gas powerplants in the supplied example take the emission rates from the Natural Gas Node, despite being linked in the I/O matrix only through the delivery node of Gas Transmission Pipeline.

The second type of emissions are accounting emissions. These are not associated with the consumption of energy products elsewhere in the energy system. Instead, these are a function of energy production in a

[95] The full list of emissions factors are found in the Excel sheet that accompanies this appendix.

node[96]. Accounting emissions rates are commonly associated with carbon capture and sequestration supply nodes or with biomass. Accounting emissions are calculated using:

Equation 16

$$G_{yr}^{acc} = E_{yr} * B_{yrn}^{acc}$$

Where

G_{yr}^{acc} = Accounting greenhouse gas emissions in the node in year y in region r

E_{yr} = Energy flow through the node in year y in region r

B_{yr}^{acc} = Node accounting emissions rate

For primary, product, and delivery nodes, the accounting emissions rate in year y in region r is exogenously specified. For conversion nodes, this is an energy-weighted stock average.

$$B_{yr}^{acc} = \frac{\sum_{t \in T} \sum_{v \in V} S_{tvyr} * b_{tvyr}^{acc}}{\sum_{t \in T} \sum_{v \in V} S_{tvyr}}$$

Where

B_{yr}^{acc} = Energy weighted average of node accounting emissions factor in year y in region r

S_{tvyr} = Stock of technology t of vintage v in year y in region r

b_{tvyr}^{acc} = Exogenous inputs of accounting emissions rate for technology t of vintage v in year y in region r

9.1.7 **Costs**

Costs are calculated using different methodologies for those nodes with infrastructure (delivery, conversion, and electric storage) and those without represented infrastructure (primary and product).

9.1.7.1 Primary and Product Nodes

Primary and product nodes are calculated as the multiplication of the energy flow through a node and an exogenously specified cost for that energy.

$$C_{yr} = E_{yr} * w_{yr}$$

Where

C_{yr} = total costs of supplying energy from node in year y in region r

E_{yr}= Energy flow through node in year y in region r

w_{yr}= Exogenous cost input for node in year y in region r

9.1.7.2 Delivery Nodes

Delivery node cost inputs are entered as per-energy unit tariffs. We use and adjust for any changes for the ratio of on-the-books capital assets and node throughput. This is done to account for dramatic changes in the utilization rate of capital assets in these nodes. This allows EnergyPATHWAYS to calculate and demonstrate potential death spirals for energy delivery systems[97], where the demand for energy from a node declines faster than the capital assets can depreciate. This pegs the tariff of the delivery node to the existing utilization rates of capital assets and increases them when that relationship diverges.

[96] For example, biomass may have a positive physical emissions rate, but biomass is considered to be zero-carbon for the Princeton study, so positive physical emissions rate is offset by a negative accounting emissions rate. For accounting purposes, this would result in the Biomass Node showing negative greenhouse gas emissions and the supply nodes that use biomass, for example Biomass Power Plants, recording positive greenhouse gas emissions.

[97] For example, if delivered energy declines by 50% while the delivery assets are only depreciated 25%, the delivery costs seen by remaining customers will increase by 50% ((1-0.25) / (1-0.5)), this creates a further incentive for customers to exit the system, whereby remaining costs are spread over an even smaller number of customers.

Equation 17

$$C_{yr} = \left(\frac{\frac{S_{yr}}{S_{yr}^{fin}}}{\sum_{y\in1} \frac{S_{yr}}{S_{yr}^{fin}}} * \frac{\sum_{y\in1} u_{yr}}{u_{yr}} * q * w_{yr} + (1-q) * w_{yr} \right) * E_{yr}$$

Where

C_{yr} = Total costs of delivery node in year y in region r

S_{yr}= Physical stock of delivery node in year y in region r

S_{yr}^{fin} = Financial stock of delivery node in year y in region r

u_{yr} = Exogenously specified utilization rate of delivery node in year y in region r

q = Share of tariff related to throughput-related capital assets, which are the only share of the tariff subjected to this adjustment.

w_{yr} = Exogenous tariff input for delivery node in year y in region r

E_{yr} = Energy flow through node in year y in region r

9.1.7.3 Conversion Nodes

Conversion node cost accounting is similar to the cost accounting of stocks on the demand-side with terms for capital, installation, and fixed O&M cost components. Instead of fuel switching costs, however the equation substitutes a variable O&M term.

Equation 18

$$C_{yr}^{stk} = C_{yr}^{cap} + C_{yr}^{ins} + C_{yr}^{fom} + C_{yr}^{vom}$$

Where

C_{yr}^{stk} = Total levelized stock costs in year y in region r

C_{yr}^{cap} = Total levelized capital costs in year y in region r

C_{yr}^{ins} = Total levelized installation costs in year y in region r

C_{yr}^{fom} = Total fixed operations and maintenance costs in year y in region r

C_{yr}^{vom} = Total levelized variable operations and maintenance costs in year y in region r

There is no difference in the calculation of the capital, installation, and fixed O&M terms from the demand-side, so reference calculation for calculating those components of technology stocks in section 9.1.3.1.9.

9.1.7.3.1 *Variable O&M Costs*

Variable O&M costs are calculated as the energy weighted average of technology stock variable O&M costs.

$$C_{yr}^{vom} = \sum_{t\in T} \sum_{v\in V} \frac{S_{tvyr} * u_{tvyr}}{\sum_{t\in T} \sum_{v\in V} S_{tvyr} * u_{tvyr}} * w_{tvry}^{vom} * E_{yr}$$

Where

C_{yr}^{vom} = Total levelized variable operations and maintenance costs in year y in region r

S_{tvyr} = Technology stock of technology t in year of vintage v in year y in region r

U_{tvyr} = Utilization rate, or capacity factor, of technology t of vintage v in year y in region r

w_{tvry}^{vom} = Exogenous input of variable operations and maintenance costs for technology t of vintage v in region r in year y

E_{yr} = Energy flow through node in year y in region r

9.1.7.4 Electric Storage Nodes

Electric storage nodes are a special case of node used in the electricity dispatch. They add an additional term, which is a capital energy cost, to the equation used to calculate the costs for conversion nodes. This is the cost for the storage energy capacity, which is additive with the storage power capacity.

$$C_{yr}^{stk} = C_{yr}^{cap} + C_{yr}^{ecap}\, C_{yr}^{ins} + C_{yr}^{fom} + C_{yr}^{vom}$$

Where

C_{yr}^{stk} = Total levelized stock costs in year y in region r

C_{yr}^{cap} = Total levelized capital costs in year y in region r

C_{yr}^{ecap} = Total levelized energy capital costs in year y in region r

C_{yr}^{ins} = Total levelized installation costs in year y in region r

C_{yr}^{fom} = Total fixed operations and maintenance costs in year y in region r

C_{yr}^{vom} = Total levelized variable operations and maintenance costs in year y in region r

9.1.7.4.1 *Electricity Capacity Costs*

Energy storage nodes have specified durations, defined as the ability to discharge at maximum power capacity over a specified period of time, and also have an input of energy capital costs, which are levelized like all capital investments.

Equation 19

$$C_{yr}^{ecap} = \sum_{v \in V} \sum_{t \in T} S_{tvyr}^{fin} * d_t * W_{tvr}^{ecap}$$

Where

C_{yr}^{ecap} = Total levelized energy capacity capital costs in year y in region r

W_{tvr}^{ecap} = Levelized energy capacity capital costs for technology t for vintage v in region r

d_t = Exogenously specified discharge duration of technology t

S_{tvyr}^{fin} = Financial stock of technology t and vintage v in year y in region r

9.2 RIO

9.2.1 **EnergyPATHWAYS/RIO Integration**

The EnergyPATHWAYS/RIO integration is a multi-step process where:

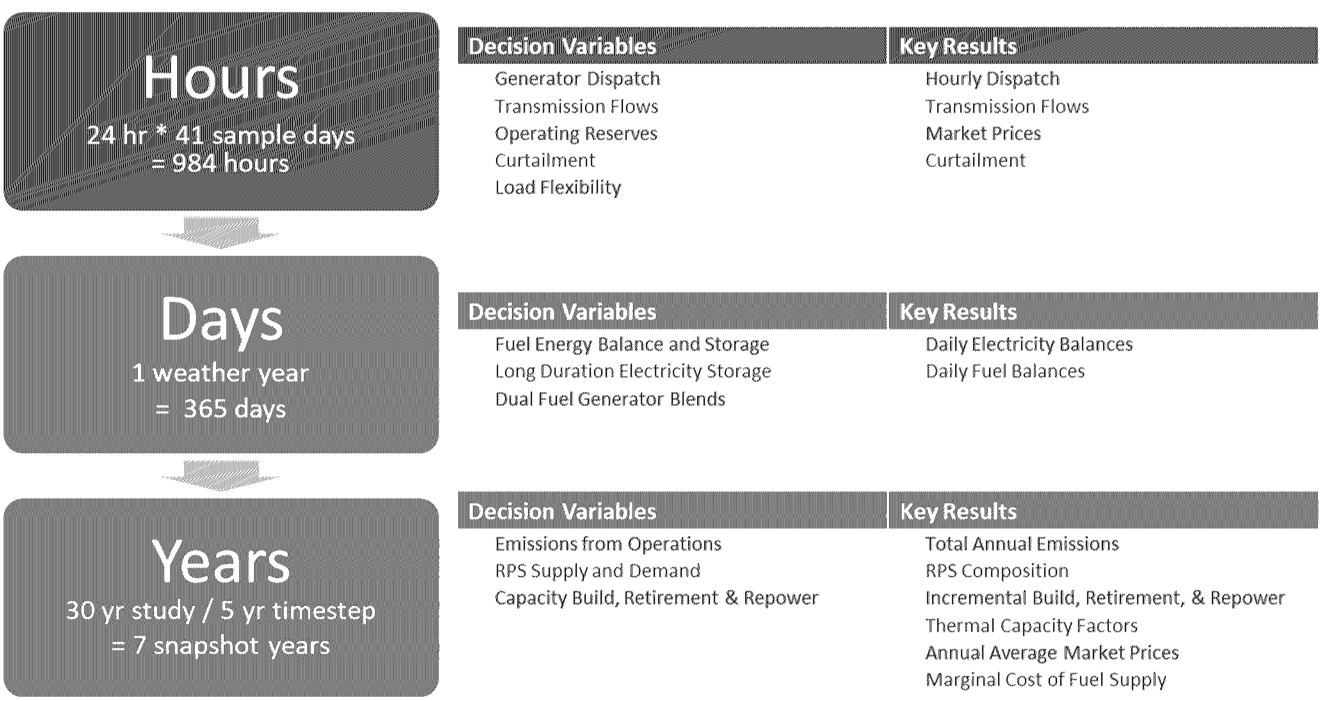
- EnergyPATHWAYS is used to define energy demand scenarios as parameterizations for RIO optimizations.
- RIO is used to optimize investments in EnergyPATHWAYS conversion supply nodes and determine optimal blends of fuel components.
- Optimized energy decisions are returned to EnergyPATHWAYS where they are input into the EnergyPATHWAYS accounting framework as stock measures or blend measures. This allows us to validate and represent the optimal scenario with the comprehensive accounting detail of EnergyPATHWAYS.

9.2.2 **Overview**

RIO is a model that sets up a linear optimization problem with the decision variables relating to capacity build and operational decisions on the supply-side of the energy system. RIO minimizes a representation of all future avoided costs in the energy system, discounted to present day using a 2% societal time preference. Operational and capacity expansion decisions are co-optimized with perfect foresight in a single optimization problem with approximately 15 million decision variables. This problem formulation means that multiple timescales are simultaneously relevant, as shown in Figure 68.

The formulation for RIO is proprietary; however, the methodology descriptions below provide the reader with a conceptual understanding of how RIO works and what advantages this approach has for the Net-Zero America study. The most important distinction between RIO and other capacity expansion models for this study was the inclusion of the fuels system, making it possible to co-optimize across the entire supply-side of the energy system, while enforcing economy-wide emissions constraints, and still maintaining very high temporal fidelity in the electric power system.

Figure 68 RIO decision variables and results for each of the represented timescales

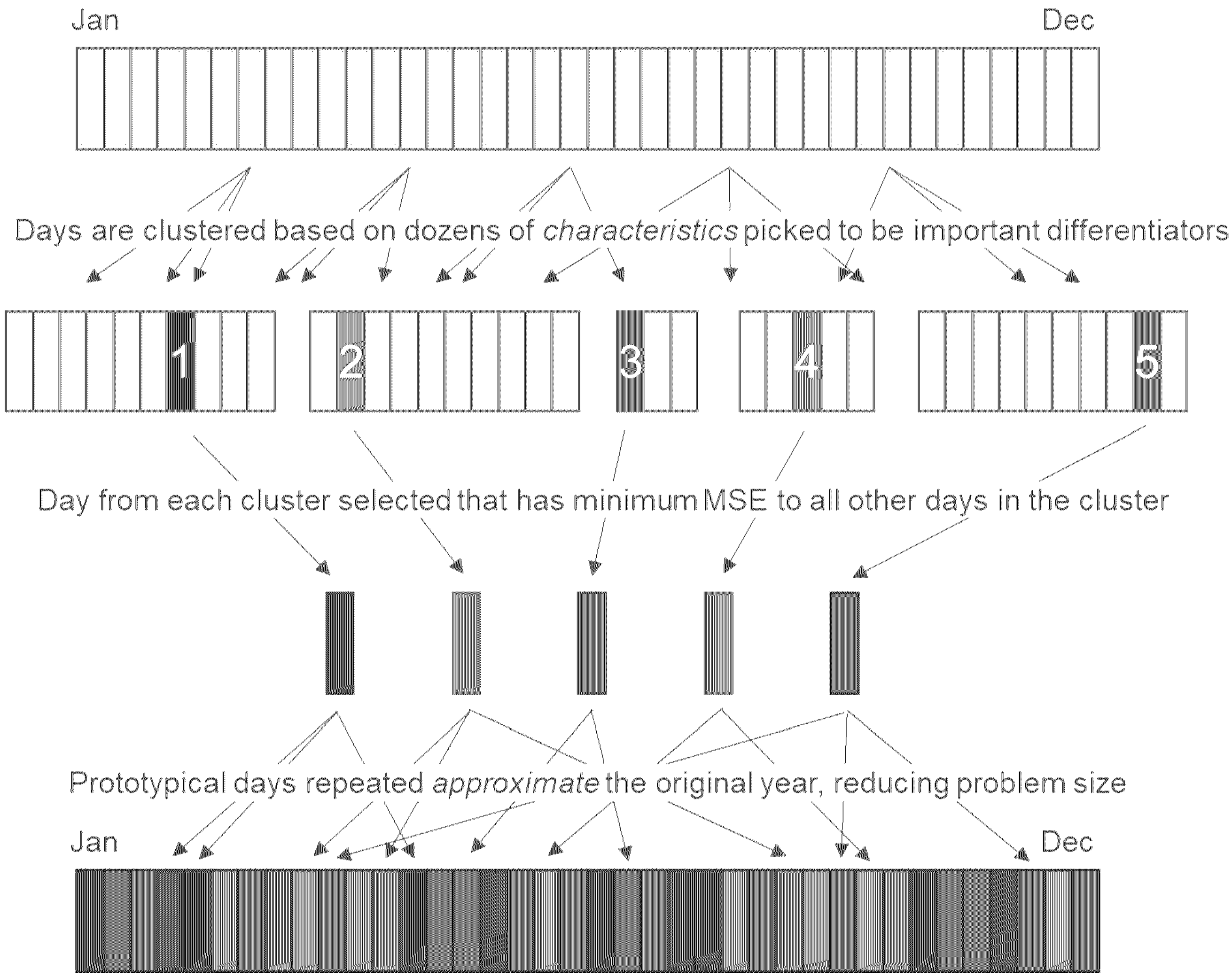


9.2.3 **Day Sampling**

RIO utilizes the 8760 hourly profiles for electricity demand and generation from EnergyPATHWAYS and optimizes operations for a subset of representative days (sample days) and maps them to the rest of the year. Operations are performed over sequential hourly timesteps. To ensure that the sample days can reasonably represent the full set of days over the year, RIO uses clustering algorithms on the initial 8760 data sets. The clustering process is designed to identify days that represent a diverse set of potential system conditions, including different fixed generation profiles and load shapes. The number of sample days impacts the total runtime of the model. A balance is struck in the day selection process between representation of system conditions through number of sample days, and model runtime. Clustering and sample day selection occurs for each model year in the time horizon. This process is shown in Figure 1. The starting dataset is the EnergyPATHWAYS load and generation shapes, scaled to system conditions for the model year being sampled and mapped. Load shapes come directly from EnergyPATWHAYS accounting runs. The coincidence of fixed generation profiles (i.e. renewables) and load determine when important events for investment decision making occur during the year. For example, annual peak load and low load events may be the coincident occurrence of relatively high loads and relatively low renewables, and the inverse, respectively. However, renewable build is determined by RIO decision making. To ensure that the sample days in each model year are representative of the events that define investment decisions, renewable scaling happens for expected levels of renewables in future years as well as a range of renewables proportional builds (for example, predominantly wind, predominantly solar). The sample days are then selected to be representative of system conditions under all possible renewable build decisions by RIO.

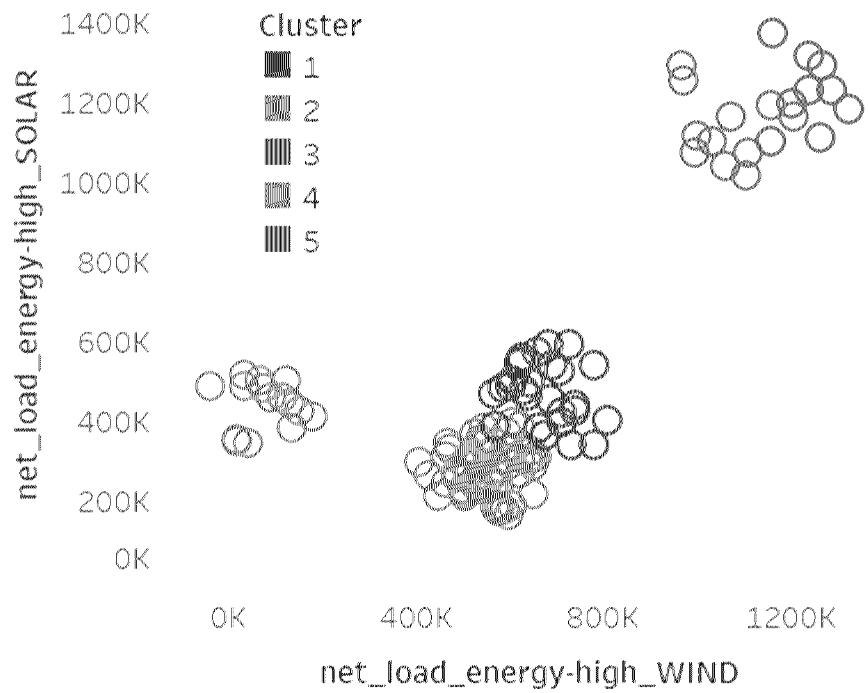
As Figure 69 shows, the scaled historical days are clustered based on a number of characteristics. These include different metrics describing every day in the data set. Examples include peak daily load, peak daily net load, lowest daily solar output, largest daily ramping event etc. The result is a set of clusters of days with similar characteristics. One day within each cluster is selected to represent the rest by minimizing mean square error (MSE). As described in the previous section, RIO determines short-term operations for each of these representative days. For long-term operations, each representative day is mapped back to the chronological historical data series, with the representative day in place of every other day from its cluster.

Figure 69. Conceptual diagram of sampling and day matching process



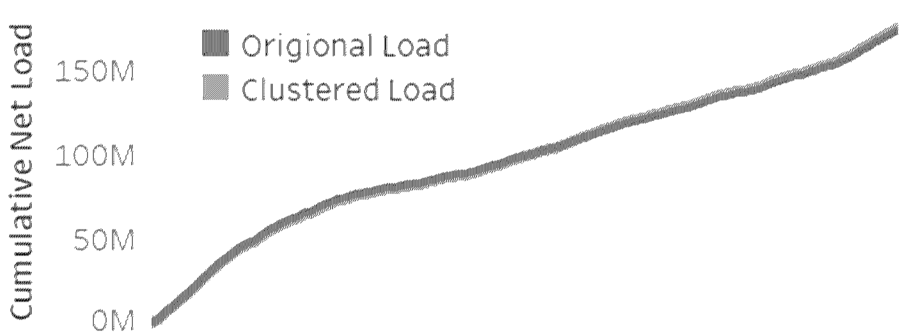
The clustering process depends on many characteristics of the coincident load and renewable shapes and uses statistical clustering algorithms to determine the best set of sample days. Figure 70 shows a simple, two characteristic, example of clustering. In this case the two characteristics are net load with high proportional solar build and net load with high proportional wind build. It is important to select sample days that both represent the full spectrum of potential net load, as well as be representative for both the solar and the wind case. The clustering algorithm has identified 5 clusters (a low number, but appropriate for the conceptual example) that ensure the sample days will represent the full range of net load differences among days and remain representative regardless of whether RIO chooses to build a high solar system or a high wind system. In the Net-Zero America Study, a total of 41 sample days were used.

Figure 70 Simple, two characteristic, example of clustering



Mapping the clustered days back to the chronological historical dataset, the newly created year of sample days can be validated by checking that metrics describing the original historical dataset match those of the new set. Cumulative net load in Figure 71 is one example. These are related to the characteristics used to select the sample days in the clustering process such as peak load, largest ramp etc. and the distribution of these over the whole year.

Figure 71 Comparison of original and clustered load



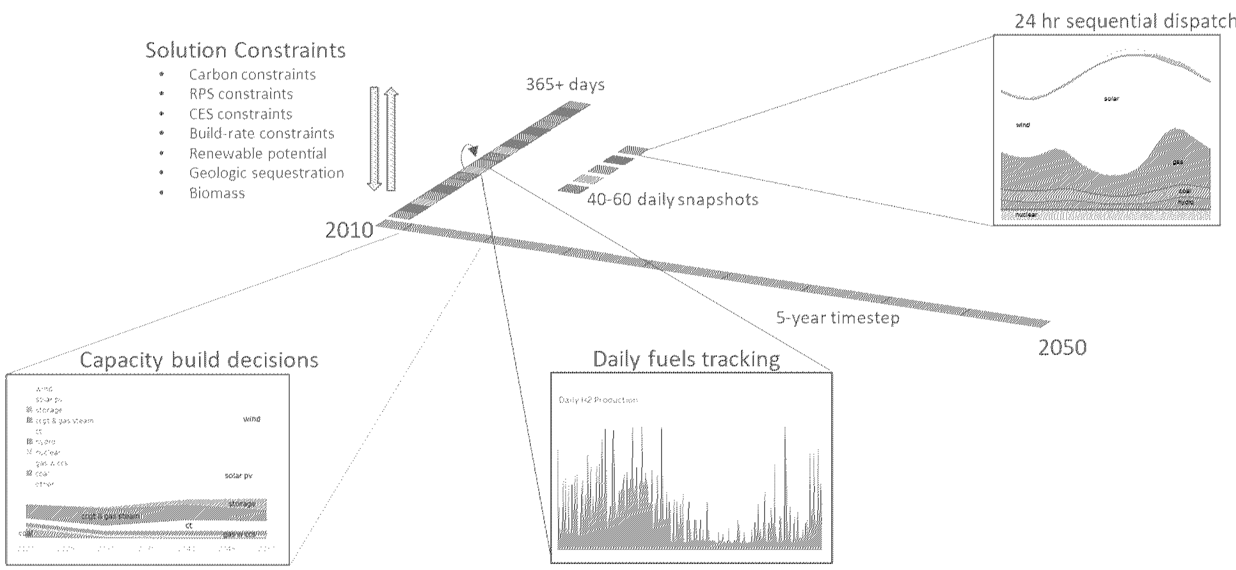
9.2.4 **Operations**

Time sequential operations are an important component of determining the value of a portfolio of resources. All resources have a set of attributes they can contribute to the grid, including, for example, energy, capacity, ancillary services, and flexibility. They work in complimentary fashion to serve the needs of the system. Whether a portfolio of resources is optimal or not depends on whether it can maintain system reliability, and whether it is cheaper than other portfolios. RIO determines the least cost dispatch for each one of the sample days to determine the least cost investments to make.

Operations are split into short-term and long-term operations in RIO. This is a division between those resources that do not have any multiday constraints on their operations, i.e. they can operate in the same way regardless of system conditions, and those resources that will operate differently depending on system condition trends that last longer than a day. An example of the former is a gas generator that can produce the same output regardless of system conditions over time, and an example of the latter is a long-duration storage system whose state of charge is drawn down over time when there is not enough energy to charge it. The long-term category includes all long-term storage mediums.

Operational decisions determine the value of one investment over another, so it is important to capture the detailed contributions and interactions of the many different types of resource that RIO can build. The overall RIO operational framework is shown in Figure 66.

Figure 72 RIO operations framework



9.2.4.1 Thermal Generator Operations

To reduce runtimes, generators are aggregated in RIO by common operating and cost attributes. These are by technology and vintage when the operating costs and characteristics vary significantly by installation year. Each modeled aggregation of generators contains a set of identical generators.

RIO can constrain operations based on constraints that are similar to those used in production simulation. Many of the plant-level operational constrains were ignored for the purpose of this study as they have secondary importance when modeling large regional zones and add significant computational complexity, which would have disallowed focus on other modeling aspects of higher importance in decarbonized energy systems (e.g. operation of electrolysis and hydrogen storage).

9.2.4.2 Hydro Operating Constraints

Hydro behavior is constrained by historical data on how fast the hydro system can ramp, the minimum and maximum discharge by hour, and the degree to which hydro energy can be shifted from one period to another.

Summed daily hydro output over user defined periods of the year must fall within a cumulative energy envelope that allows up to 2 weeks of shift in the dispatch compared to historical levels.
Canadian imports to the Northeastern U.S. include a small amount of planned expansions but otherwise reflect the existing energy flow volume.

9.2.4.3 Storage Operating Constraints

Storage is constrained by maximum discharge rates dependent on built capacity. In addition, the model tracks storage state of charge hour to hour, including losses into and out of the storage medium. Storage, like all technologies, is dispatched with perfect foresight. Storage can operate through both short term and long-term operations. In short term operations, storage is dispatched on an hourly basis within each sample day, as with all other dispatchable technology types. Short term storage dispatch shifts energy stored within a sample day and discharges it within the same sample day, such that the short-term storage device is energy neutral across the day. In long term operations, storage can charge energy on one day and discharge it into another. This allows for optimal use of storage to address longer cycle reliability needs, such as providing energy on low renewable generation days, and participation in longer cycle energy arbitrage opportunities.

9.2.4.4 Transmission constraints

RIO uses a pipe-flow constraint formulation[98]. Transmission flows are constrained by the capacity of the line in every hour. When transmission is built by the model, additions are assumed to be symmetrical, meaning the capability of flow on the line is equal in both directions. However, not all existing transmission has equally sized paths in each direction. Transmission losses are specified by path and transmission hurdles[99] start from a benchmark against historical flows before converging at $5/MWh in 2040.

9.2.5 **Reliability**

The conditions that will stress electricity systems in the future and define reliability need will shift in nature compared to today, shown in Figure 67. Capacity is the principle need for reliable system operations when the dominant sources of energy are thermal. Peak load conditions set the requirement for capacity because generation can be controlled to meet the load and fuel supplies are not constrained. As the system transitions to high renewable output, the defining metric of reliability need is not peak load but net load (load net of renewables). Periods with the lowest renewable output may drive the most need for other types of reliable energy even if they do not align with peak gross load periods. In addition to that, resources will become increasingly energy constrained. Storage can only inject the energy it has in charge into the system. Reliability is therefore increasingly driven by energy need as well as capacity need.

In the future, the defining reliability periods may be when renewables have unusually low output, and when that low output is sustained for unusually long periods. To model a reliable system in the future, both capacity and energy needs driven by the impact of weather events and seasonal changes on renewable output and load need to be captured.

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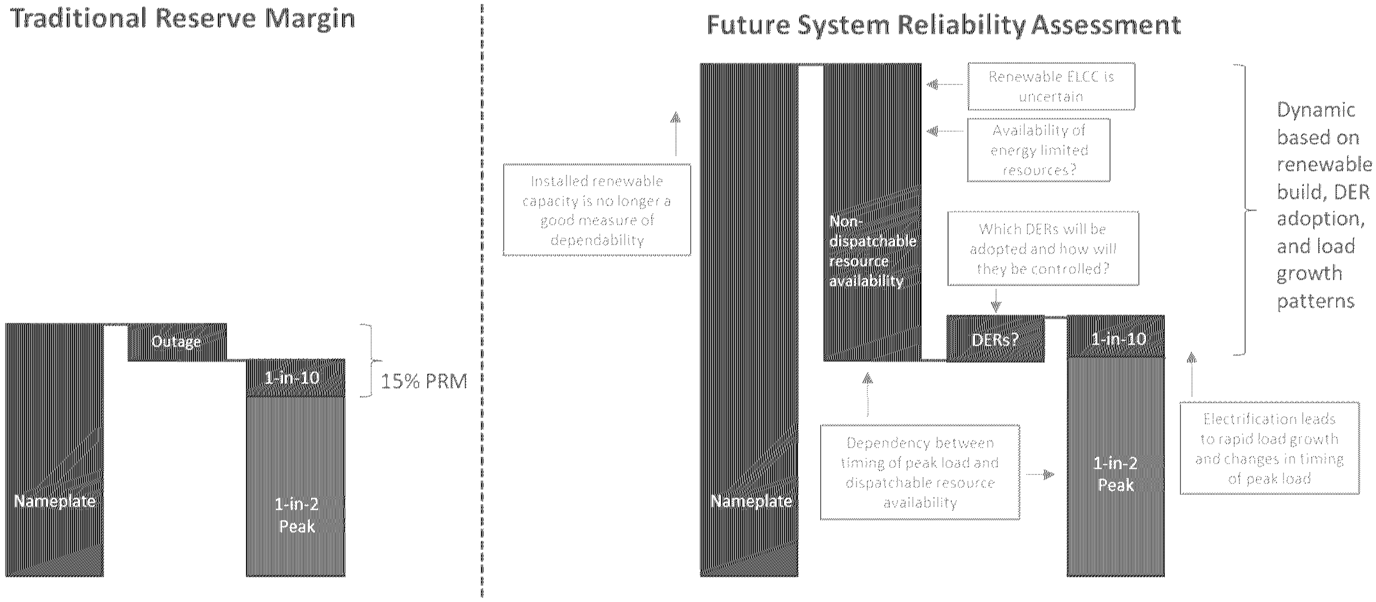
[98] See this NREL presentation for more information and contrast against DC power-flow constraint formulations: National Renewable Energy Laboratory, Transmission Flow Methodologies: Approximate DC Flow vs. Pipe Flow along AC Lines, September 2017, https://www.nrel.gov/docs/fy17osti/68929.pdf
[99] Hurdle rates are a common mechanism in power system models and represent friction between zones. These costs are not 'true' costs, but instead represent a penalty on transmission flows, which is added to the objective function.

Figure 73 Reliability framework in high renewable systems



To ensure we capture the impacts of these changing conditions on reliability, we enforce a planning reserve requirement on load in every modeled hour. This "planning demand" is found by scaling load up to account for the possibility that demand in each hour could be greater than expected. At the same time, we determine a dependable contribution of each resource to meeting the planning demand. Dependability is defined as the output of each resource that can be relied upon during reliability events. The planning demand must be met or exceeded by the summed dependable contributions of available resources in each hour.

9.2.5.1 Dependability

The dependable contribution from thermal resources is derated nameplate, reflecting forced outage rates. Renewable dependable contribution is the derated hourly output, reflecting that renewable output could be even lower than expected. For energy constrained resources such as hydro and storage, dependable contribution is derated hourly output. By using derated hourly output we can capture both the risk that it is not available because of forced outage, and the risk that it is not available because it has exhausted its stored energy supply. Dependability factors used for the Net-Zero America study are shown in Table 22.

Table 26 Dependability factors used when enforcing RIO reliability constraints

Resource	Dependability
Existing Thermal Resources	93% applied to nameplate
New Thermal Resources	93% applied to nameplate
Transmission	90% applied to hourly flows
Energy storage	95% applied to hourly charge/discharge
Variable generation (wind & solar)	80% applied to hourly output
Electricity load	106% applied to hourly load

9.2.5.2 Resource build decisions

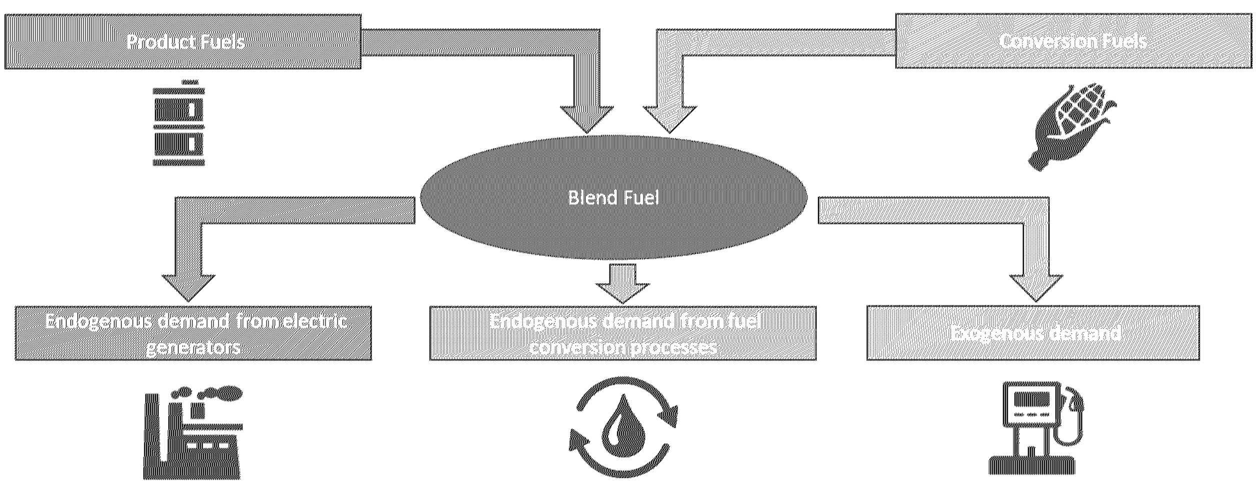
Concurrently with optimal operational decisions, the model makes resource build decisions that together produce the lowest total system cost. There are three modes for resource build decisions, specified by aggregate generator. In all modes, the addition of new capacity is limited by the rate at which capacity can be constructed year on year, and the total quantity of capacity that can be constructed by a future year. The model builds resources when needed and those resources remain through the end of their useful life when they are retired. Resources are not economically retired early, repowered, or extended. Generators using this mode are built on top of a predefined MW schedule of existing resources in every year.

9.2.6 **Fuels**

In addition to electricity, RIO optimizes the composition of fuels that are used in electric generators and that go to satisfy final energy demands, calculated in EnergyPATHWAYS. RIO fuels operate around the concept of a 'blend fuel' shown in Figure 68. Each fuel blend may be supplied using 'product fuels', which are basically commodities (e.g. dry biomass, fossil diesel) that are specified at a price and quantity, or blends can be supplied with fuel conversions, which can convert one blend fuel into another or convert electricity into a fuel (e.g. electrolysis).

Fuel conversion technologies are included in the capacity expansion framework of RIO, thus decision variable cover both the build and operations of each conversion technology. The capital cost, O&M costs, and conversion efficiencies for all conversion technologies are given in the accompanying Excel workbook.
Fuel conversions that consume or produce electricity[100] can be specified as flexible or inflexible on an hourly basis. Electrolysis and electric boilers are assumed to operate flexibly, all other conversion technologies, including direct air capture, are not flexible hour-by-hour.

Figure 74 RIO fuels framework



[100] Conversion technologies can have electricity as a co-product.