Rhode Island Investigation into the Future of the Regulated Gas Distribution Business

Technical Analysis Appendix A
Modeling Methodology
Docket 22-01-NG

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Energy+Environmental Economics

Energy and Environmental Economics (E3) is an analytically driven consulting firm focused on the transition to clean energy resources with offices in San Francisco, Boston, New York, Calgary, and Denver. Founded in 1989, E3 delivers analysis that is widely utilized by governments, utilities, regulators, and developers across North America. E3 completes roughly 350 projects per year, all exclusively related to the clean energy transition, across our three practice areas: Climate Pathways and Electrification, Integrated System Planning, and Asset Valuation, Transmission, and Markets. The diversity of our clients – in their questions, perspectives, and concerns – has provided us with the breadth of experience needed to understand all facets of the energy industry. We have leveraged this experience and garnered a reputation for rigorous, unbiased technical analysis and strong, actionable strategic advice.

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A.1 Economywide Pathways and Emissions

The E3 PATHWAYS Model

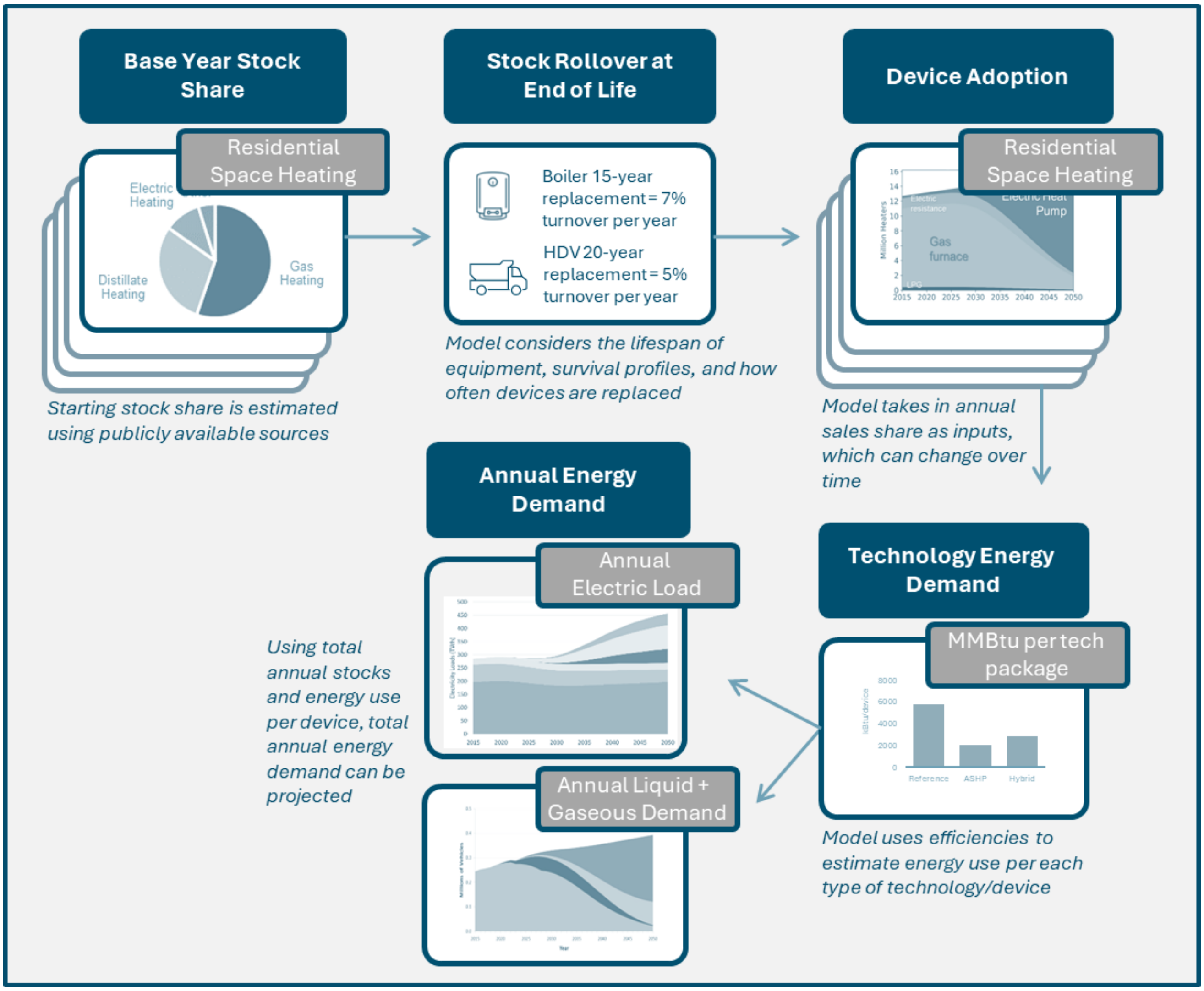
The E3 PATHWAYS model identifies the interactions between GHG measures across different sectors of the economy, such as transportation, buildings, and industry. Utilizing an economywide representation of technology, infrastructure, energy use, and emissions, the model enables an evaluation of long-term decarbonization scenarios and analyzes the associated cost impacts under different world views or GHG mitigation targets. The model was developed by E3 in 2008 to support policymakers' analysis of different decarbonization scenarios and their impact on each part of the economy. E3 has continued to improve the PATHWAYS model over time and has used the model to support long-term decarbonization planning for many jurisdictions, including New York, California, Colorado, Maryland, Massachusetts, Minnesota, and more.

The E3 PATHWAYS model uses a stock rollover approach, which tracks the timing of investments and subsequent turnover for the replacement of appliances, vehicles, buildings, and other equipment (see Figure 1). The methodology accounts for the time lag between annual sales of new devices and how the overall population of device stock will evolve over time. Each type of equipment has a different lifetime, which is captured by the stock rollover approach. Some technologies, like lightbulbs, have lifetimes of just a few years, whereas others, like building shells, have lifetimes of several decades. The PATHWAYS model uses the stock rollover methodology and the lifetimes of different technologies to determine the pace of technology deployment that is required in order to meet GHG reduction targets. The model also considers performance improvements and increases in efficiency over time for each type of technology. For some sectors of the economy, like industry, the PATHWAYS model only tracks energy demand over time, since there is very limited data on equipment. The model also considers some emissions-only subsectors, where the emissions are non-energy related (i.e., not related to the combustion of fuel), such as agriculture, fugitive methane emissions, industrial processes, waste, and LULUCF.[1]

It is important to note that the PATHWAYS model does not generate "optimal" paths to decarbonization, nor does it highlight the "most likely" outcomes; instead, the PATHWAYS model is designed to produce "what if" scenarios related to economywide decarbonization.

[1] LULUCF: Land use, land use change, and forestry

Figure 1. Schematic Overview of E3's PATHWAYS Model



Key PATHWAYS Parameters

E3's PATHWAYS model is built upon user-defined key drivers and sector-specific parameters that inform building and transportation stock levels, industrial energy consumption, non-energy emissions, and renewable fuel blends. Key assumptions for the PATHWAYS model include economywide drivers, building stock characteristics, transportation stock characteristics, energy efficiency parameters, emissions factors, and industrial demand drivers. Key drivers are based on Rhode Island-specific data from 2018. E3 used 2018 as the model benchmark year because:

- There is access to more complete data and benchmarking sources for 2018 as opposed to later years.
- The year 2018 reflects normal conditions in Rhode Island (e.g., heating degree days are within 5% of the median as shown in Figure 2).
- The COVID-19 pandemic caused a dip in normal activities, leading to abnormally low energy demand in 2020-2021, as shown in Figure 3.

The reference and decarbonization scenarios still mirror actual data (using public sources such as the State Energy Data Systems, or SEDS) for the years 2018-2022, and only meaningfully begin to diverge in the year 2024.

Figure 2. Heating Degree Days (HDDs) in Rhode Island 1979-2020

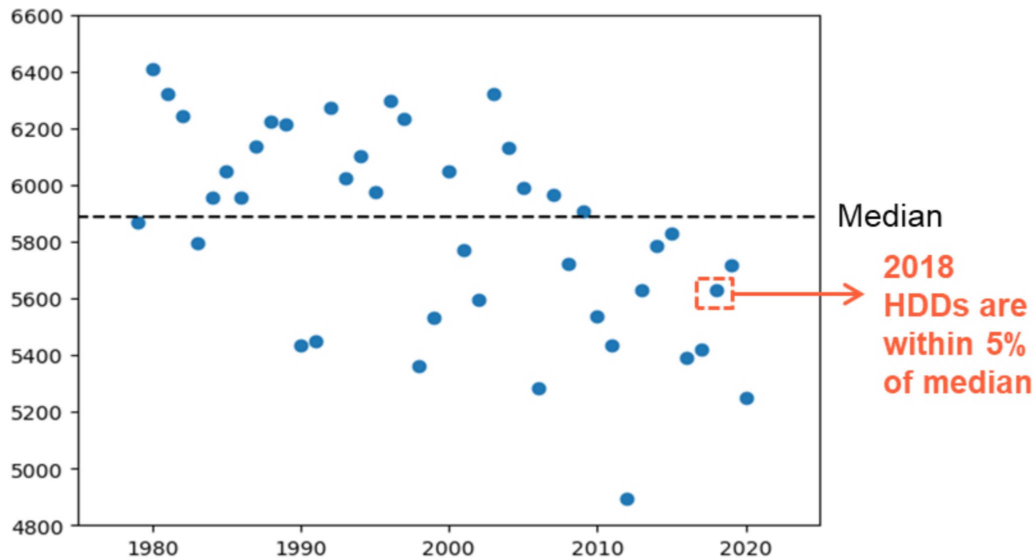
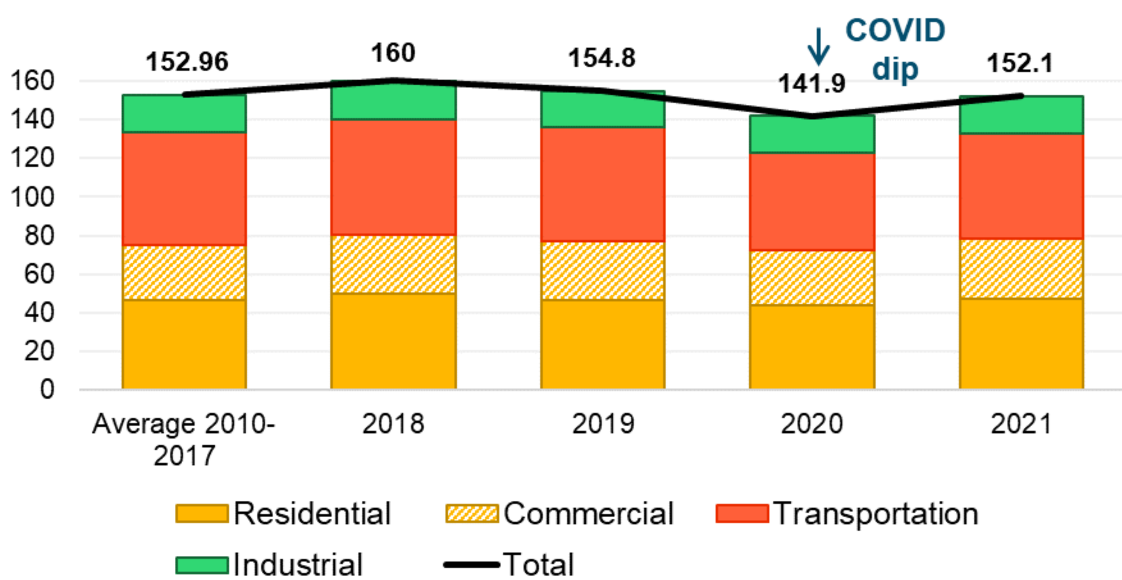


Figure 3. Economywide Energy Demand in Rhode Island (Tbtu)



Economywide Key Drivers

- **Population and growth.** In 2018, Rhode Island counted approximately 1.059 million inhabitants. Population in the state is expected to decrease slightly over time, at a rate of about -0.1% per year through 2050 according to the Rhode Island Statewide Planning Program.[2]

- **Housing units and growth.** As of 2018, Rhode Island had 470,000 total housing units, of which about 407,000 were occupied. Housing units are expected to decline by about -.07% annually, with the slight decrease due to population decline.[3]
- **Commercial square footage and growth.** As of 2018 there is about 302 million square feet of commercial space in Rhode Island with no anticipated growth over time.[4]
- **Industrial fuel demand growth.** Energy consumption in the industrial sector varies by subsector, with detailed assumptions included in Appendix B.[5]
- **Vehicle-miles traveled (VMT).** Vehicle miles traveled per vehicle vary by vehicle class. Light duty vehicles had an estimated VMT per vehicle of 11.59 thousand miles in 2018, with an annual growth rate of 1.30%. A detailed overview of all assumptions related to vehicle-miles traveled can be found in Appendix B.

Buildings

A primary focus of this study is the role of building heating technology transformations in Rhode Island's transition to a decarbonized energy future. Types of heating technology transformations include building electrification, transition to networked geothermal systems, and/or the increased reliance on high-efficiency fossil fuel-powered technology.

Building Baseline Assumptions

Rhode Island's residential building stock is made up of 59% single family homes, 40% multifamily, and 1% mobile homes.[6] Single family homes include those that are 1-unit, detached or attached, and multifamily homes include all buildings with 2 or more units. Today, residential buildings primarily rely on gas and distillate space heating, with a smaller dependence on electric resistance space heating. Single family space service demand is estimated to be about 91.5 MMBtu/household and multifamily space heating service demand about 25.5 MMBtu/household. Today, residential water heating in Rhode Island is primarily comprised of gas storage, distillate, and electric resistance heaters.

Rhode Island has about 302 million square feet of commercial space. Commercial buildings in the state also rely heavily on gas and distillate space heating today. Commercial space heating service demand is estimated to be approximately 40 kbtu/sqft.

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[2] Rhode Island Statewide Planning Program Rhode Island Population Projections 2010-2040. https://planning.ri.gov/sites/g/files/xkgbur826/files/documents/census/tp162.pdf.

[3] U.S. Census Bureau, American Community Survey. https://data.census.gov/table?q=DP04&g=040XX00US44&y=2018.

[4] RI Office of Energy Resources (OER). https://energy.ri.gov/HST.

[5] Baseline energy consumption from SEDS, growth %s from AEO 2020

[6] Based on Census American Community Survey data: https://data.census.gov/table?tid=ACSDP5Y2021.DP04&g=040XX00US44

Building Electrification

Building electrification includes the transition of space heating, water heating, cooking, and clothes drying appliances from fossil fuel-powered technologies to electrified technologies. A key parameter in the design of each scenario is the role that electrified space heating technologies will play versus the impact of maintaining reliance on the gas system in buildings. Another important focus area of the study is the impact of different *types* of electrified space heating technologies, including the comparison of all-electric heat pumps vs. hybrid heat pumps with different types of fossil fuel backup (delivered fuels vs. natural gas). Building electrification parameters for each decarbonization scenario include:

- **High Electrification**: Explores the impact of switching building equipment to primarily all-electric technologies, including a limited role for networked geothermal space heating. The scenario is designed to reach nearly 100% all-electric heating by 2050, including about 10% networked geothermal adoption. A small portion of the building stock converts to hybrid heat pumps.[7]
- **Hybrid with Delivered Fuels Backup**: Explores the impact of primarily hybrid heat pumps/boilers with delivered fuels backup plus a smaller role for all-electric technologies. This scenario is designed to reach 50-70% hybrid heating adoption by 2050, with about 30-50% all-electric heating. About one third of existing delivered fuels space heating stocks are assumed to switch to all-electric ASHPs or electric boilers, with about two thirds transitioning to hybrid heat pumps/boilers with delivered fuels backup. In this scenario, gas to hybrid with delivered fuel backup conversions are incorporated in order to facilitate gas system decommissioning.
- **Hybrid with Gas Backup:** Explores the impact of primarily hybrid heat pumps/boilers with gas backup plus a smaller role for all-electric technologies. This scenario is designed to reach 50-70% hybrid heating adoption by 2050, with about 30-50% all-electric heating. A small portion of existing fuel customers convert to hybrid with delivered fuels backup instead of to hybrid gas heat pumps.
- **Staged Electrification:** Explores the impact of primarily hybrid heat pumps/boilers adoption in the near term, while switching to all-electric technologies in the long term. This scenario is designed to reach about 80-90% all-electric heating by 2050, with about 30-40% hybrid heating. Buildings convert to hybrid heat pumps in the short term, and then transition to all-electric heating after 2030.
- **Alternative Heat Infrastructure:** Explores the impact of highly efficient heating systems, such as networked geothermal as an alternative to gas investments. This scenario is designed to reach 30-50% all-electric heat pumps, 30-40% hybrid heat pumps (primarily gas), and about 30% networked geothermal adoption by 2050.

[7] Note for all scenarios where hybrid with delivered fuels backup is not a key focus, e.g., High Electrification, Hybrid with Gas Backup, Alternative Heat Infrastructure, and Continued Use of Gas, the number of hybrid heat pumps with delivered fuel backup adoption was kept constant to facilitate clear comparisons.

- **Continued Use of Gas:** Explores how the existing gas infrastructure and blending of renewable fuels can be used to support decarbonization goals, with a lower reliance on building electrification. This scenario is designed to reach 20-40% all-electric heating and 40-50% efficient gas heating by 2050. A modest portion of the building stock converts to hybrid heat pumps with gas backup in order to reach emissions targets, and a small amount transitions to hybrid heat pumps with delivered fuels backup, at the same level as High Electrification, Hybrid with Gas Backup, and Alternative Heat Infrastructure.

Networked Geothermal Adoption

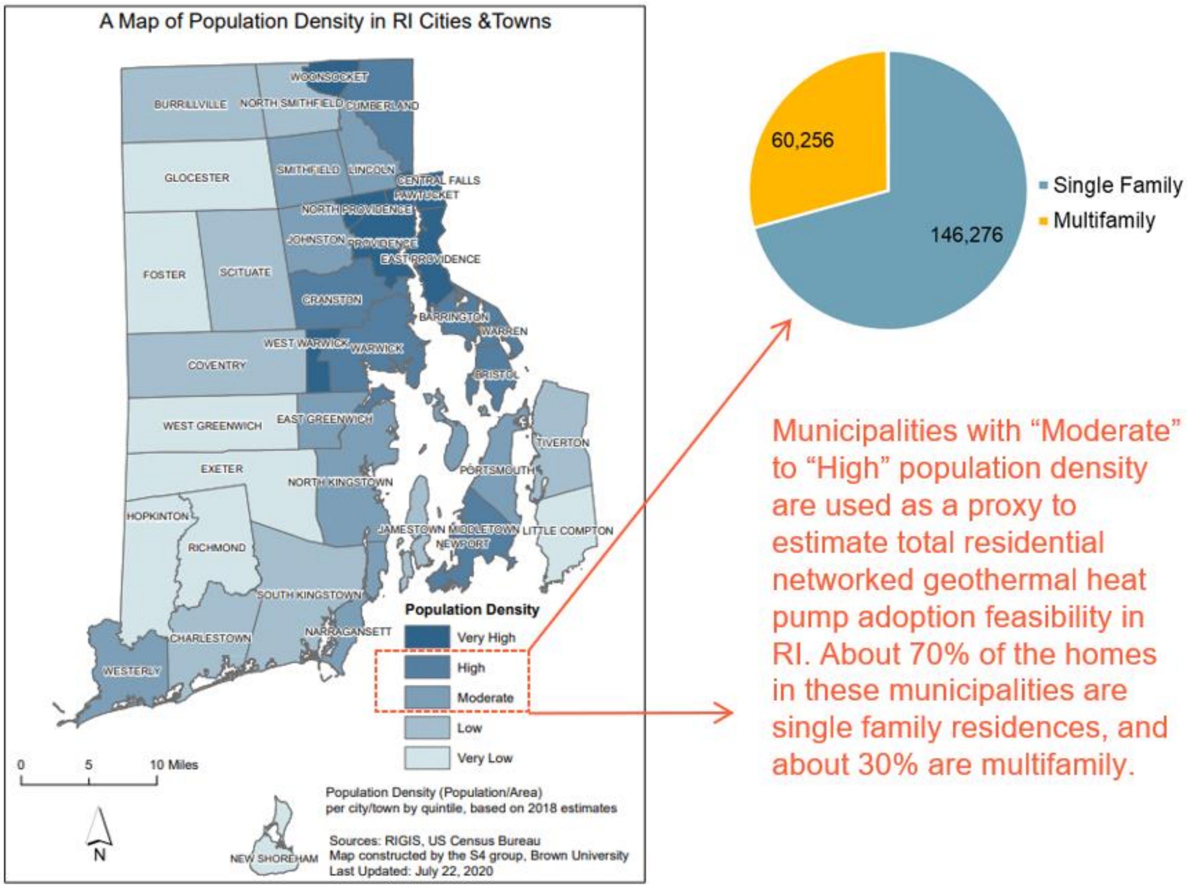
In addition to the adoption of pumps, this study explores the role that networked geothermal systems can play in building decarbonization, particularly if networked geothermal systems could enable the partial decommissioning of the gas system. Networked geothermal systems are closed vertical ground-source heat pump systems that connect several buildings to a central infrastructure. Advantages of networked geothermal include minimization of weather dependency of electric heating and the potential for load sharing between buildings. However, there are significant uncertainties with regard to feasibility of networked geothermal adoption.

Research shows that the feasibility of networked geothermal systems is highly location specific. Networked geothermal systems rely on a central infrastructure, so they must be built in a relatively dense area. At the same time, the Geothermal Networks Feasibility Study by HEET excluded "very high" density areas as infeasible to convert.[8] Using Rhode Island's 2022 Integrated Housing report, E3 estimated that about 43% of Rhode Island existing housing units are in municipalities with "Moderate" to "High" population density (see Figure 4).[9] For the Alternative Heat Infrastructure scenario that has relatively high levels of networked geothermal, E3 assumed that about 70% of the households in these "Moderate" to "High" population density areas can convert to networked geothermal by 2050. This makes up about 30% of total housing units.

[8] HEET, Buro Happold Engineering. 2019. Geothermal Networks 2019 Feasibility Study. https://assets-global.website-files.com/649aeb5aaa8188e00cea66bb/656f8ad67bbc7df081e3fe17_Buro-Happold-Geothermal-Network-Feasibility-Study.pdf.

[9] RI Office of Housing and Community Development. 2022. Integrated Housing Report https://ohcd.ri.gov/media/2351/download.

Figure 4. Networked Geothermal Feasibility Map for Residential Buildings[10]

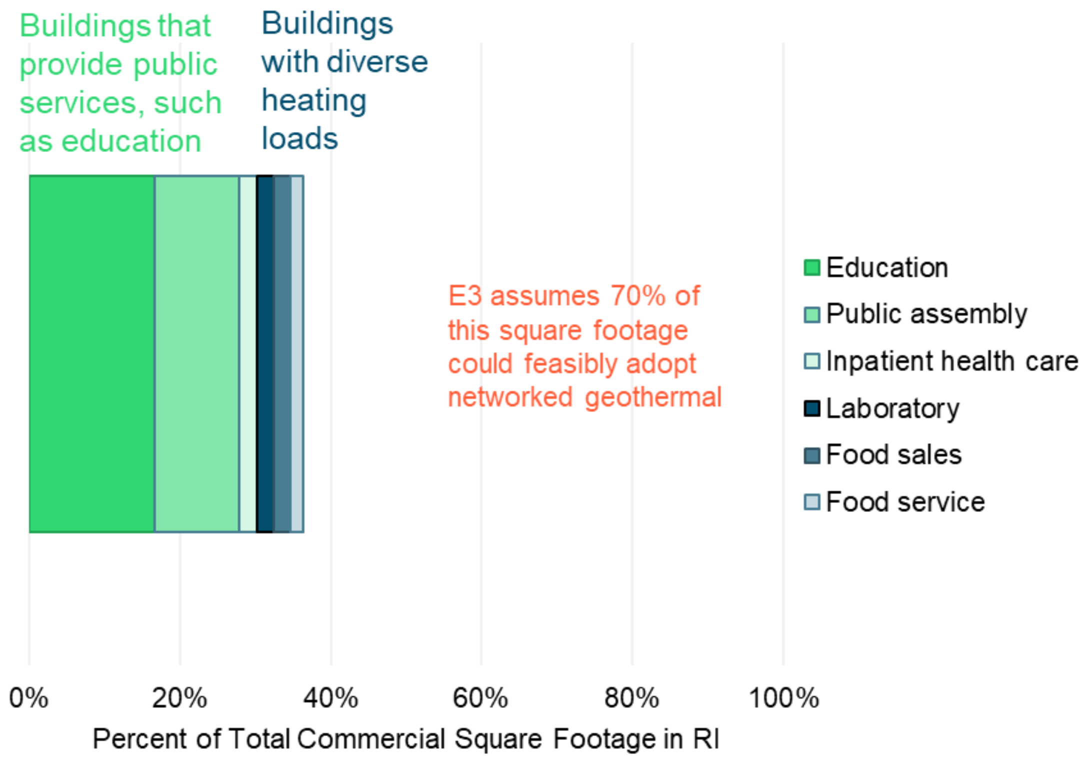


The commercial sector offers several opportunities for networked geothermal adoption. As of 2023, many district heating and cooling systems in the U.S. are on college campuses. In the Alternative Heat Infrastructure scenario, E3 assumed that about 70% of the following building types could reasonably adopt networked geothermal systems by 2050, totaling about 25% of all commercial square footage in Rhode Island (see Figure 5):

+ Buildings that provide public services including education (e.g., college campuses), public assembly, and healthcare;
+ Buildings with diverse heating loads that can complement other loads on a networked geothermal system, including labs, food services, and food sales.

[10] Map image source: *2022 Integrated Housing Report* [*https://ohcd.ri.gov/media/2351/download*](https://ohcd.ri.gov/media/2351/download)

Figure 5. Assumed Feasibility for Networked Geothermal Adoption in Commercial Buildings[11]



Efficient Fuel-Powered Heating Technology

The Continued Use of Gas scenario is the only pathway that relies heavily on efficient gas equipment in the long term. By 2029, all gas furnaces will convert to efficient furnaces per the Energy Conservation Standards for Consumer Furnaces; in this scenario, about 40-50% of buildings will continue to rely on that equipment through 2050, with some transitioning to all-electric or hybrid heat pumps in order to reach emissions requirements.

Transportation

Baseline Transportation Assumptions

Rhode Island's transportation sector today is highly dependent on fossil fuels for on-road equipment; light-duty vehicles primarily use gasoline while medium- and heavy-duty vehicles use a mix of diesel and gasoline. In 2020, the transportation sector in Rhode Island consumed approximately 54 Tbtu of

[11] Source: EIA CBECS

energy, making it Rhode Island's highest energy-consuming sector. A detailed overview of energy consumption and baseline stock share is included in Appendix B.

Zero-Emission Vehicles

Zero-emission vehicle (ZEV) adoption levels are held constant across all scenarios. The light-duty vehicle (LDV) and medium- and heavy-duty vehicle (MHDV) electrification trajectories are driven by the adoption of Advanced Clean Cars II (ACCII) and Advanced Clean Trucks (ACT) in Rhode Island. ACCII is a California emissions standard for passenger cars and trucks (i.e., LDVs) that requires vehicle manufacturers to incrementally increase zero-emission vehicle (ZEV) sales in Rhode Island, reaching 100% by 2035, with interim targets in between. E3 assumed that the majority of LDV ZEVs will be battery electric by 2035, with a small portion of plug-in hybrid. ACT is a California emissions standard for medium- and heavy-duty (MHDV) vehicles that requires manufacturers to increase zero-emission MHDV sales in RI. Unlike ACCII, ACT does not require 100% ZEV sales by 2035, and instead mandates a more gradual increase to zero-emissions MHDVs with specific targets determined by vehicle weight class.

Industry

Industry Baseline Assumptions

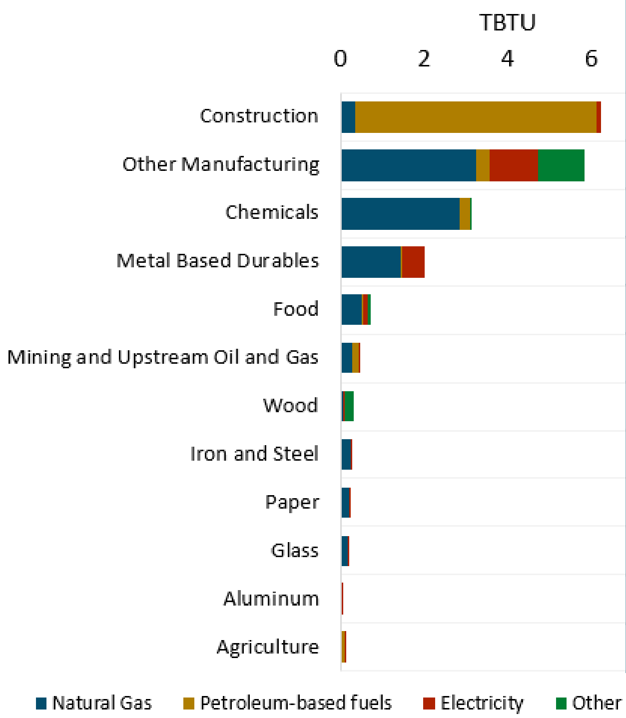
E3 used the Energy Information Administration (EIA) State Energy Data System (SEDS) and the Manufacturing Energy Consumption Survey (MECS) to determine the existing type and quantity of energy used by industrial subsector. Appendix B includes detailed assumptions for baseline energy demand by subsector and projected industrial growth rates.

E3 assumed that industrial manufacturing efficiency would improve over time, resulting in a 1% decrease in energy consumption each year.

Industrial Electrification and Fuel Switching

In 2021, the industrial sector in Rhode Island consumed approximately 19 Tbtu of energy, mostly from construction, chemicals, and manufacturing (see Figure 6). Industrial electrification potential in the design of scenarios is based upon the type of energy use by process for each subsector. Energy used for boilers, cogeneration, combined-heat-and-power (CHP), and HVAC systems was assumed to have a relatively high electrification potential. Hard-to-electrify energy use includes energy consumed for high-temperature process heat. For energy use types that are unknown or not reported, there is less certain electrification potential, but most of this energy likely comes from on-site transportation and machinery.

Figure 6. Consumption of Energy in the Industrial Sector by Process

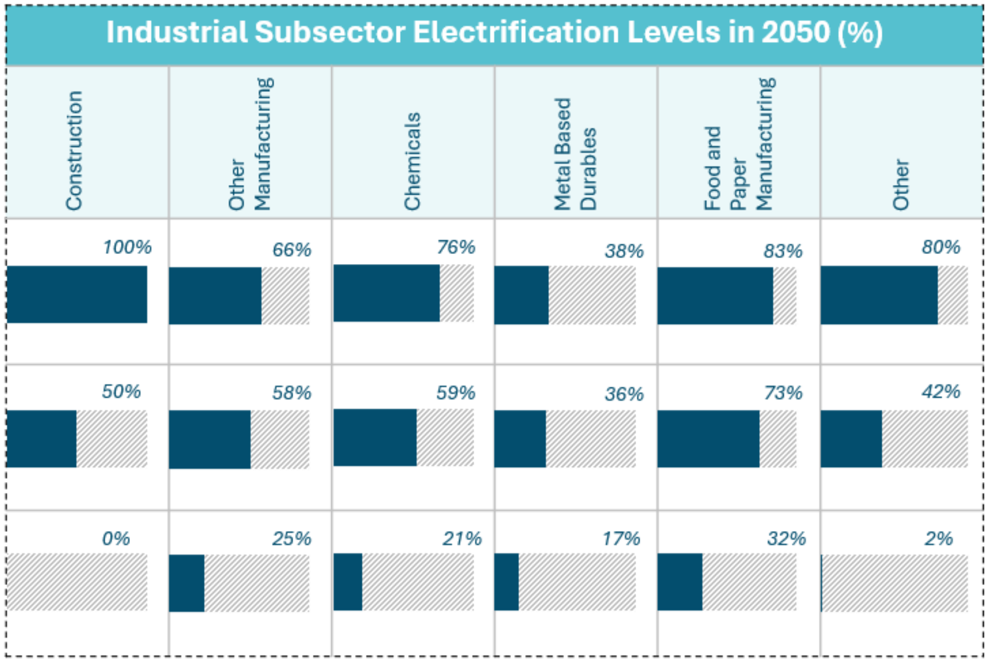


% of energy use for high-temperature process heat	% of energy use for boiler use, cogen, HVAC and other	% of energy use unknown/not reported
0%	0%	100%
35%	50%	15%
24%	42%	34%
62%	34%	4%
20%	54%	26%
0%	0%	100%
0%	0%	100%
37%	10%	53%
8%	91%	1%
74%	5%	21%
78%	19%	3%
0%	0%	100%

Key subsectoral electrification modeling assumptions are outlined below and total subsector electrification by scenario is shown in Figure 7:

+ **Hard-to-electrify processes.** Across all scenarios, E3 assumed there would be no electrification for hard-to-electrify processes. These are processes that use energy for high-temperature process heat in Figure 6.
+ **Processes with high electrification potential**. For processes with high electrification potential, including energy use for boilers, cogen and HVAC, E3 modeled 100% electrification for all scenarios except Continued Use of Gas. In the Continued Use of Gas scenario, 50% of that energy use is assumed to electrify.
+ **Processes with uncertain electrification potential.** For scenarios with high levels of electrification, such as High Electrification, Staged Electrification, and Hybrid with Delivered Fuels Backup, an optimistic approach was applied to the processes with less certain electrification potential, assuming 100% could be electrified. For scenarios with medium levels of electrification, such as Hybrid with Gas Backup and Alternative Heat Infrastructure, E3 assumed about half of the processes with less certain electrification potential could successfully electrify. For the Continued Use of Gas scenario, E3 assumed none of the on-site transportation and machinery processes would electrify, relying on low-carbon fuel switching instead.

Figure 7. Industrial Subsectoral Electrification Levels in 2050 (%)



Energy Efficiency Parameters

Energy efficiency is a critical component of all decarbonization strategies and will play an important role in Rhode Island's path to net zero emissions. The Technical Analysis incorporates many forms of energy efficiency measures across multiple sectors, such as weatherization and building shell retrofits, technology performance improvements, appliance standards and in-kind high-efficiency replacements (e.g., lighting upgrades), behavioral conservation, and industrial manufacturing efficiency.

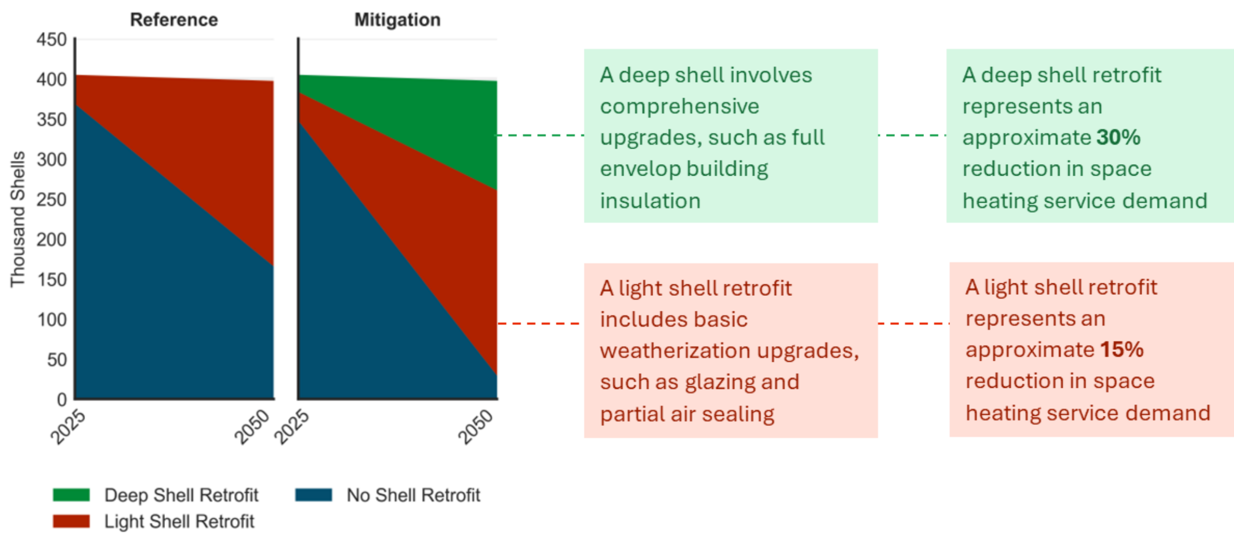
Weatherization and Building Shells

Building energy efficiency assumptions deployed in the reference and decarbonization scenarios were supported by research from NV5, a technical engineering and consulting firm supporting the Rhode Island Energy Efficiency and Resource Management Council (EERMC) in the Future of Gas Docket. Leveraging deep industry expertise and the Rhode Island Energy Efficiency Market Potential Study Refresh, NV5 put together a set of assumptions regarding weatherization adoption rates under both reference and decarbonization scenario conditions for E3 to utilize in the Technical Analysis.[12] Adoption rates varied by building type (single family, multifamily, commercial) and fuel type (natural

[12] Additional data sources listed include: NREL Data Lake, C&I Building Demographic Data, MA Clean Energy and Climate Plan, RIE/National Grid Program Performance Data

gas, oil, propane). Overall, it is estimated that nearly 60% of Rhode Island's residential building stock will undergo light-touch energy efficiency retrofits by 2050 in the reference scenario (see Figure 8).

Figure 8. Building Shell Assumptions Across Scenarios

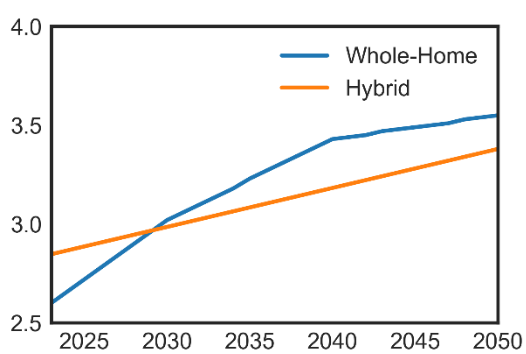


Heat Pump Efficiency

Building electrification involves the switch from a fossil fuel-powered device to one powered by electricity. Electrification is a form of efficiency because heat pumps are able to meet heating service demands much more efficiently than conventional combustion technologies.

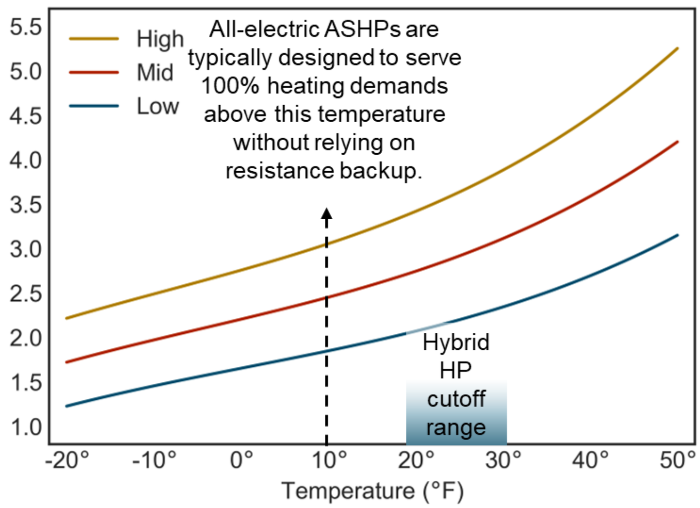
A variety of space heating technologies were modeled in this work, including standard and efficient combustion devices, several types of air-source heat pumps (ASHPs), networked geothermal, and ground source heat pumps. In general, all device efficiencies were assumed to either improve or remain static over time. The details for the efficiencies of each of these devices can be found in Appendix B.

Figure 9. Single-family Whole-Home and Hybrid Heat Pump Annual Efficiency



The remainder of this section will focus on the evolution of ASHP performance during the modeling period. ASHP device efficiency improvements in PATHWAYS are based on the Electrification Futures Study "Moderate" trajectory.[13] As shown in Figure 9, early in the study period, whole-home heat pumps are assumed to be less efficient than hybrid heat pumps. Since the latter heat pumps avoid operation during the coldest hours of the year, their annual efficiencies will be higher than an otherwise identical whole-home heat pump. As the study period progresses, whole-home heat pumps are assumed to become more efficient than hybrid heat pumps on an annual basis. This more rapid increase in efficiency is driven by advances in heat pump technology beyond what is commonly available today, which mitigates poor performance at cold temperatures.

Figure 10. RESHAPE Heat Pump Archetype Efficiencies as a Function of Temperature.



As shown in Figure 10, E3 modeled three different heat pump archetypes with varying efficiency curves. PATHWAYS whole-home heat pumps were primarily represented by mid-efficiency heat pumps with a design temperature of approximately 10 ˚F. The compressors were assumed to run below the design temperature but were supplemented by electric resistance. While modern heat pump engineering and sizing practice can allow for the heat pump to meet a building's entire demand below the balance point temperature without relying on a backup, whole-home heat pump compressors were assumed to be supplemented by electric resistance. Hybrid heat pumps were assumed to be sized to 20-25 ˚F, switching over completely to backup fuel below that temperature.

E3 modeled sensitivity assumptions related to the efficiency of ASHPs, as explained in more detail in the section on sensitivities below.

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

Appliance Standards and In-Kind Replacements

Regardless of electrification, buildings will adopt higher efficiency technologies over time, in compliance with more stringent appliance codes and standards and in-kind efficiency replacements. For example, the Energy Conservation Standards for Consumer Furnaces requires that all gas-powered furnaces be 95% efficient by 2029; these higher-efficiency furnaces will require a lower amount of energy to meet heating demands. Another example is lighting; while today many buildings in Rhode Island rely on incandescent bulbs and CFLs, it is anticipated that by 2027 100% of new lighting sales will be LEDs.

Smart Devices and Behavioral Conservation

The E3 PATHWAYS model also considers the impact of smart energy devices and changes to human behavior that reduce energy service demand (also known as “behavioral conservation” measures). Smart devices include smart lighting systems, i.e., those that automatically turn off lights based on sensors or other indicators, and smart thermostats, which are Wi-Fi enabled and automatically adjust indoor air temperature in buildings to meet occupant’s needs. Behavioral conservation measures include human choices that result in reduced service demand, like turning off the light when not home, or turning down the heat when leaving for vacation. Table 1 below shows the reductions in service demand that are included in the PATHWAYS model to reflect smart devices and behavioral conservation in Rhode Island.

Table 1. Annual Reduction (%) in Service Demand Due to Smart Devices and Behavioral Conservation

Building Subsector	2030	2050
Residential Central Air Conditioning	2%	2%
Residential Room Air Conditioning	2%	2%
Residential General Service Lighting	2%	2%
Residential Exterior Lighting	2%	2%
Residential Linear Fluorescent Lighting	2%	2%
Residential Single Family Space Heating	2%	2%
Residential Multifamily Space heating	2%	2%
Commercial Air Conditioning	12%	12%
Commercial High Intensity Discharge Lighting	12%	12%
Commercial Linear Fluorescent Lighting	12%	12%
Commercial General Service Lighting	12%	12%
Commercial Space Heating	12%	12%

Emissions

Emissions Factors

E3 aligned all emissions factors with those in the Rhode Island Department of Environmental Management (RIDEM)'s 2020 GHG Inventory.[14] The inventory primarily relies upon the Environmental Protection Agency (EPA)'s emissions accounting framework reported in the State Inventory Model (SIT). The accounting framework assumes a 100-year Global Warming Potential (GWP) based on the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5).[15] The GWP is a metric of how much a given gas, such as methane (CH_4) or nitrous oxide (N_2O), will contribute to global warming compared to carbon dioxide (CO_2) over a certain time period. By definition, CO_2 has a GWP of 1 so that it can be used as the reference gas.[16] GWPs enable the comparison between different gases by putting all climate pollution effects into a single metric – in this case based on a 100-year time horizon. AR5 GWPs used by the RI 2020 GHG Inventory are shown in Table 2 below.

Table 2. IPCC AR5 GWPs

Pollutant	AR5 Global Warming Potential (GWP)
CO_2	1
CH_4	28
N_2O	265

Other key factors in Rhode Island's current emissions accounting methodology include:

+ **Consumption-based electricity accounting.** The electric sector uses a consumption-based emissions accounting method. A consumption-based framework accounts for all emissions associated with electricity used within the state, rather than generated within the state.[17]
+ **Net Zero GHG accounting.** The current netting methodology in Rhode Island involves summarizing all GHG sources and then subtracting all GHG sinks, rather than netting for individual GHGs.[18]

[14] Rhode Island 2020 Greenhouse Gas Inventory. Available at: https://dem.ri.gov/environmental-protection-bureau/air-resources/greenhouse-gas-emissions-inventory
[15] IPCC AR5: https://www.ipcc.ch/assessment-report/ar5/
[16] Source: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials
[17] https://dem.ri.gov/sites/g/files/xkgbur861/files/programs/air/documents/ghg-memo.pdf
[18] Net Zero GHG accounting was confirmed by RI Department of Environmental Management (RIDEM) on the Stakeholder Committee.

- **Renewable fuels**. Renewable fuels are considered carbon neutral in Rhode Island's current GHG emissions accounting methodology, and current emissions from biodiesel usage in the state are not reported.[19]

Appendix B includes a detailed list of all emissions factors used in the Technical Analysis.

Non-Energy Emissions

Rhode Island non-energy emissions include industrial non-energy (HFC and IPPU), waste, agriculture, and natural gas distribution. Non-energy emissions parameters are held constant across all scenarios (both reference and decarbonization scenarios). Overall, these sectors make up an exceedingly small component of Rhode Island's economywide emissions.

- **IPPU.** Across all scenarios, IPPU emissions are held constant at 0.01 MMT CO2e.
- **HFCs**. Across all scenarios, HFCs decline by about 80% in compliance with the Kigali Amendment of the Montreal Protocol.
- **Agriculture.** Across all scenarios, emissions from the agricultural sector are expected to remain flat over time (at 0.03 MMT CO2e), as reflected in historical trends from the RI GHG Inventory.
- **Waste.** Across all scenarios, solid waste emissions decline to zero by 2048 after Rhode Island's Central Landfill closure in 2038, consistent with the 2016 RI GHG Reduction Plan.[20] Wastewater emissions are held flat at 0.10 MMT CO2e over time.
- **Natural gas distribution.** Across all scenarios, natural gas distribution system emissions decrease based on improvements from the leak-prone pipe replacement program, as plastic pipelines and services are assumed a much lower emissions factor compared to cast iron and steel. Emissions factors from the distribution system are derived directly from the GHG Inventory, which relies on SIT data. In addition to a reduction in emissions stemming from the change in material types, it is assumed that a reduction in services and reduction in mileage of mains would lead to a reduction in emissions from the gas distribution system. This type of reduction occurs primarily for scenarios with high levels of customer departures that reduce the number of services on the system over time (High Electrification, Hybrid with Delivered Fuels Backup, Staged Electrification), and in scenarios that avoid gas system infrastructure in the managed transition sensitivity.

[19] Rhode Island 202 GHG Emissions Inventory. https://dem.ri.gov/sites/g/files/xkgbur861/files/2023-10/2020%20RI%20GHG%20Emissions%20Inventory%20Summary.pdf

[20] RI EC4. 2016. Rhode Island Greenhouse Gas Emissions Reduction Plan. https://climatechange.ri.gov/sites/g/files/xkgbur481/files/documents/ec4-ghg-emissions-reduction-plan-final-draft-2016-12-29-clean.pdf.

Carbon Sinks

Netting emissions is the process of accounting for both sources of emissions and sinks, which are natural conditions that cause emissions to be absorbed.[21] Netting is done by summarizing all GHG emissions and then subtracting all GHG sinks on an annual basis.

Forests, croplands, grasslands, wetlands, and settlements are Rhode Island's primary carbon sinks. E3 calculated the potential for carbon sequestration from forests in Rhode Island using data from the RI 2020 Forest Action Plan.[22] The plan reports that about one acre of Rhode Island forest absorbs 1.3 tCO2 annually, and there is about 368,000 acres in Rhode Island total. In the reference scenario, E3 assumed that Rhode Island would experience annual forest, wetland, and cropland loss consistent with historical patterns as outlines in the 2020 Forest Action Plan, e.g., 838 acres of forest loss per year, leading to slight reductions in carbon sinks over time. In decarbonization scenarios, E3 assumed that Rhode Island would experience no net forest, wetland, cropland loss, in line with the 2016 RI GHG Reduction Plan. No net forest loss implies the adoption of conservation measures and that new developments will be built denser and on already-developed lands.

Renewable Fuel Blending

All scenarios rely on some level of renewable fuel blending to meet Act on Climate targets and/or comply with existing legislation – approximately 50-70% of the fuel mix across all scenarios consists of renewable fuels by 2050. At a minimum, all scenarios comply with the Biodiesel Heating Act which requires 20% biodiesel blend for oil customers in 2025 and 50% blend starting in 2050. Outside of the Biodiesel Heating Act, dependence on renewable fuels is lowest in scenarios that rely most strongly on electrification and highest in scenarios that rely on the maintenance of the gas system.

E3 selected which types of fuels to blend based on the most cost-effective options, e.g., prioritizing renewable diesel over renewable gasoline. Dedicated hydrogen is used in the industrial sector for the Hybrid with Gas Backup, Alternative Heat Infrastructure, and Continued Use of Gas scenarios. Table 3 below shows the total volume of renewable fuels in 2030 and 2050 by scenario.

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[21] Definitions from EC4.

[22] RI Department of Environmental Management (DEM). 2020. Forest Action Plan (SFAP). https://dem.ri.gov/natural-resources-bureau/agriculture-and-forest-environment/forest-environment/forestry-info-0#:~:text=The%202020%20SFAP%20is%20a,ground%20implementation%20of%20these%20funds.

Table 3. Renewable Fuel Volumes in 2030 and 2050 Across Scenarios (Tbtu)

Scenario	Renewable Diesel		Renewable Natural Gas		Renewable Jet Kerosene		Renewable Gasoline		Hydrogen	
Year >>	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
High Electrification	4.4	5.5	0	1.9	0	3.4	0	0	0.2	1.8
Hybrid w/DF Backup	5.2	10.1	0.9	1.9	0	3.4	0	0	0.2	1.8
Hybrid w/Gas Backup	4.4	5.6	1.3	6.2	0	3.6	0	0	0.6	3.0
Staged Electrification	4.8	5.9	1.3	2.1	0	3.4	0	0	0.2	1.8
Alternative Heat Infra.	4.5	5.7	1.5	4.1	0	3.6	0	0	0.6	3.0
Continued Use of Gas	4.6	6.2	5.7	22.3	0	4.3	0	0.4	1.0	4.5

Sensitivities Impacting Level and Pace of Emissions Reductions

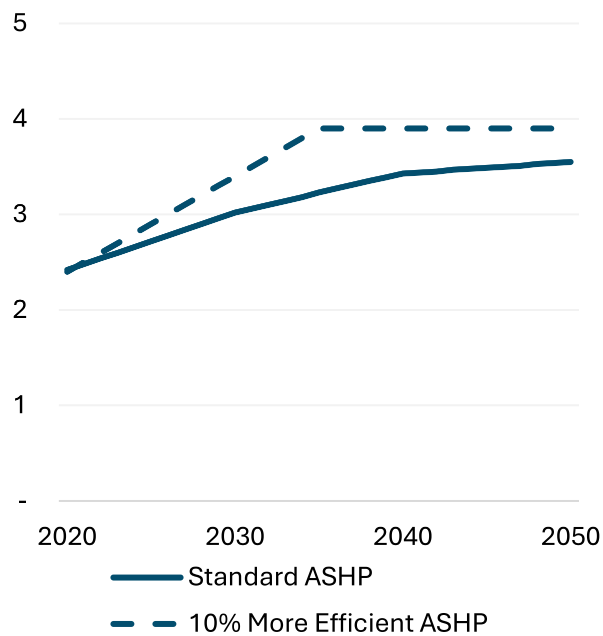
Due to the inherent uncertainty in all assumptions-based PATHWAYS modeling, E3 explored three primary types of sensitivities that vary the level and pace of emissions reductions under different conditions:

- **Higher Cold Climate Heat Pump Efficiency Performance**
  - Modeled as a sensitivity on building sector energy demands and electric capacity needs.
  - Modeled for the High Electrification scenario only.
- **Lower Levels of Transportation Electrification**
  - Modeled as a sensitivity onto transportation sector technology adoption levels
  - Modeled for the High Electrification scenario only.
- **Different GHG Accounting Frameworks**
  - Modeled as a sensitivity onto fuel emissions factors through 3 options:
    - Lifecycle emissions associated with fuels
    - 20-year GWP
    - No emissions benefits from renewable fuels
  - Modeled for all scenarios

Higher Cold Climate Heat Pump Efficiency Performance

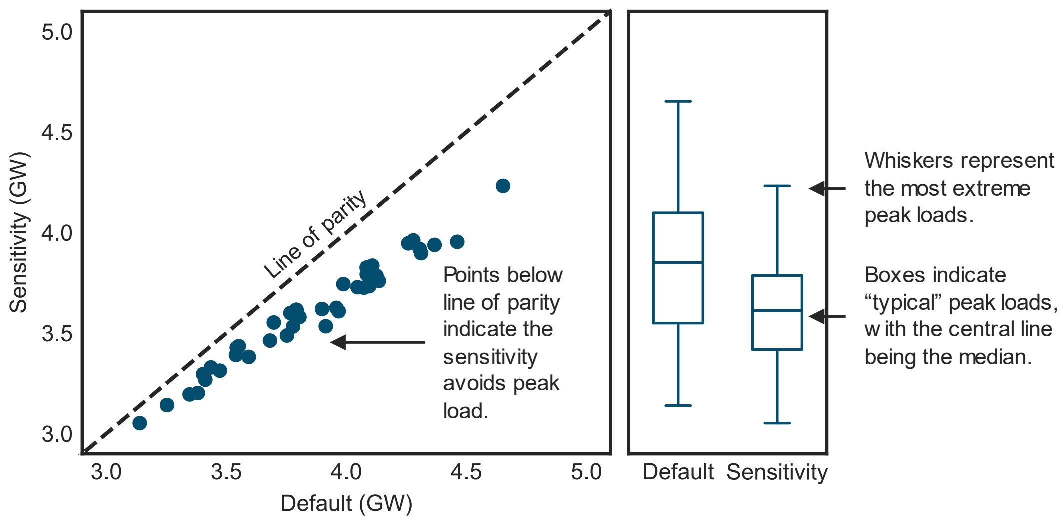
To explore the electric sector impacts resulting from the adoption of higher efficiency all-electric technology, E3 modeled an approximate 10% increase in Coefficient of Performance (COPs) for ASHPs and hybrid ASHPs by 2050 in the High Electrification scenario only, as shown in Figure 11. These higher-efficiency heat pumps primarily correspond to the “High” heat pump curve in Figure 10, sized to serve 100% of all heating demands (without using electric resistance backup). These heat pumps, in particular, are designed to mitigate peak load impacts of heat pump systems that would otherwise require an electric resistance backup.

Figure 11. COPs for Standard vs. High Efficiency ASHP



The results of this sensitivity analysis show that higher efficiency heat pumps can avoid system peak impacts by 250-300 MW under median peak heating conditions (see Figure 12). Under the most extreme conditions, high-efficiency heat pumps can avoid up to 500 MW of peak load before load flexibility. High-efficiency heat pumps avoid peak load under increasingly extreme conditions by 1) avoiding supplemental electric resistance and 2) operating the compressor itself at higher levels of efficiency. Under the most extreme conditions, high-efficiency heat pumps can avoid up to 500 MW of peak load before load flexibility.

Figure 12. Peak Load Results From The High-Efficiency High Electrification Sensitivity



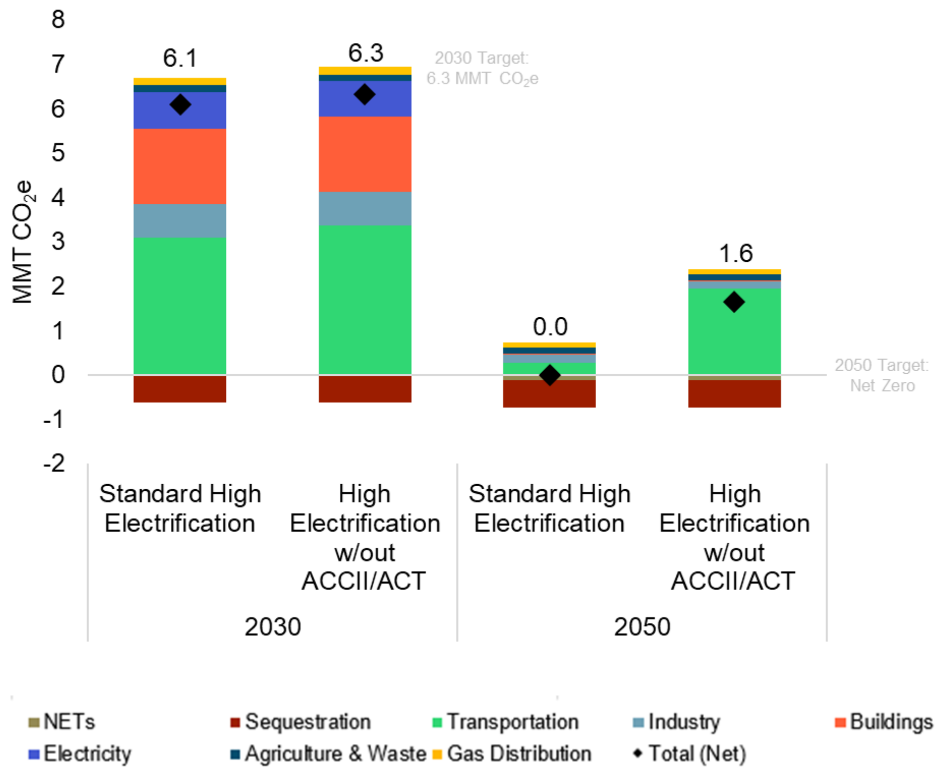
Lower Levels of Transportation Electrification

E3 modeled the impact on emissions if the Transportation sector was not able to meet the targets as set out by ACCII/ACT in the High Electrification scenario. To conduct this sensitivity, E3 modeled transportation electrification in High Electrification as following the same trajectory as the reference scenario, i.e., EV penetration will meet targets as laid out by EC4 (e.g., 10% of LDV stocks by 2030, 35% LDV stocks by 2050). Sensitivity analysis shows that High Electrification would meet the 2030 target even if ACCII/ACT follows a slower trajectory in the short term. This is due to accelerated action in the buildings sector that are required to reach longer term climate goals.[23] However, in the longer term, the High Electrification scenario would not hit emissions targets; the High Electrification scenario would have approximately 1.65 MMT CO2e remaining in 2050, thus missing the 2050 net zero emissions target by about 14%. In High Electrification, the buildings sector is completely electrified. Thus, if the ACCII/ACT is not achieved, higher renewable fuel blending in the Transportation sector will be required.[24] In other mitigation scenarios, deeper building electrification measures can be adopted if the ACCII/ACT is not met.

[23] The High Electrification scenario is designed to avoid blending of renewable fuels in the long term. As a result of slow stock rollover, accelerated adoption of building electrification in the near term is required to achieve this objective, resulting in deeper emissions reductions than required in the AoC.

[24]

Figure 13. Remaining Emissions with and without ACCII/ACT (High Electrification Scenario)



Alternative GHG Accounting Frameworks

This study uses the Rhode Island state emissions inventory as its primary basis for emissions accounting. Through sensitivity analysis, E3 estimated the impact on remaining emissions if Rhode Island were to adopt alternative GHG accounting frameworks, including different GWP parameters, upstream emissions and zero emissions benefits associated with renewable fuels. An overview of the methodology for each sensitivity is outlined in the sections below, with remaining emissions results in 2050 under each sensitivity in Figure 14.

20-year GWP

While a 100-year GWP was used in the standard Technical Analysis modeling, for this sensitivity, E3 explored the impact of a 20-year GWP instead. The largest impact comes from the natural gas distribution sector, where methane leaks will have a much near-term global warming impact under a 20-year GWP.

Upstream emissions for all fuels

For the characterization of life cycle emissions in the heating sector, E3 leaned on findings from existing literature to derive upstream emissions factors for renewable fuels, as well as upstream emissions associated with counterfactual fuels.

E3 conducted a literature review to explore existing values for upstream renewable natural gas (RNG) emissions factors that exclude credits for avoided methane. E3 utilized emissions intensities found in these sources to calculate an average upstream emissions factor for RNG (gasification and anaerobic digestion), as seen in Table 4. Under this sensitivity, combustion emissions of CO_2 from RNG are still considered to be carbon-neutral since the fuel's sources are from biogenic carbon.

In order to allow for apples-to-apples comparisons across fuels and scenarios, E3 also considered the upstream emissions factors for fossil fuels in this sensitivity analysis – such as natural gas and diesel in the buildings and industrial sectors. E3 referred to the *New York State (NYS) Statewide GHG Emissions Report* to derive upstream emissions factors for natural gas and distillate fuel, given the relative proximity of Rhode Island to New York.[25] A full deep dive into upstream emissions factors for specific fuels delivered to Rhode Island was beyond the scope of this project.

All fossil fuel emissions factors (including combustion and upstream) can be found in Table 4. Further details on the calculations to derive each of these emissions factors are included in Appendix B.

[25] Ibid.

Table 4. Emission Factor Sensitivities

Sector	Fuel	Combustion EF (gCO_2e/MJ)	Upstream EF (gCO_2e/MJ)[26], [27]	Detailed assumptions
Heating Sector (Buildings & Industry)	RNG	0	Gasification: 18-67 Anaerobic digestion (AD): 40-50 Weighted average: 32.6 Transmission: 2.1 Final RNG emissions factor: 34.7	Gasification range of 18-67 gCO2e/MJ represents a variety of pathways – air, catalyst, and steam. E3 assumed 29 gCO2e/MJ. AD range is an average of EFs from landfill gas, dairy manure, municipal solid waste, and wastewater. When considering the EFs from the final linked report, a 5% leakage rate was assumed. A weighted avg. based on feedstocks in the Billion Ton Report was then calculated using gasification and AD EFs. Finally, the transmission emissions factor for natural gas was added.
	Fossil Natural Gas	50.2	20.9	Total emissions intensity is equal to combustion + upstream emissions
	Biodiesel	0	17.0	Upstream emissions factor is equivalent to counterfactual fuel
	Diesel	70.1-70.2	17.0	Total emissions intensity is equal to combustion + upstream emissions
Transportation Sector	Renewable Diesel	0	17.0	Upstream emissions factor is equivalent to counterfactual fuel
	Diesel	70.0	17.0	Total emissions intensity is equal to combustion + upstream emissions
	Renewable Jet Kerosene	0	11.8	Upstream emissions factor is equivalent to counterfactual fuel
	Jet Kerosene	67.4	11.8	Total emissions intensity is equal to combustion + upstream emissions
	Renewable Gasoline	0	21.3	Upstream emissions factor is equivalent to counterfactual fuel
	Gasoline	67.5	21.3	Total emissions intensity is equal to combustion + upstream emissions

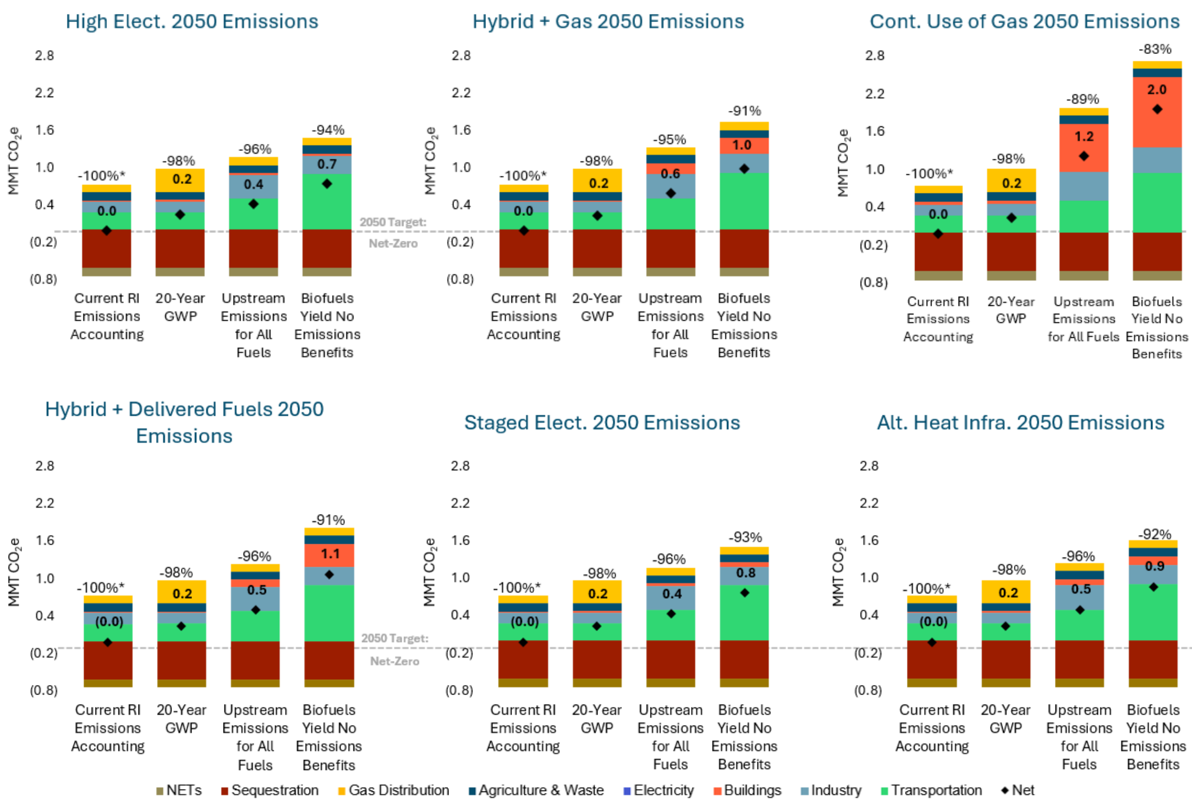
[26] Sources for RNG emissions factors: ICCT 2030 CA RNG Outlook; Comparative Life Cycle Evaluation of the GWP Impacts of RNG; At Scale, RNG Systems Could be Climate Intensive

[27] Source for all fossil upstream emissions factors: New York State Inventory Model; 2022 NYS Statewide GHG Emissions Report

Zero emissions benefits from renewable fuels

In the Technical Analysis, renewable fuels are assumed to be carbon neutral for both upstream and downstream emissions, following the GHG Inventory. The upstream emissions sensitivity explores the impact on emissions if upstream lifecycle production emissions are considered for all fuels. In addition, a sensitivity was performed where renewable fuels are assumed to not contribute to emissions reductions. In this analysis, renewable fuels are assigned the same downstream combustion emissions factor as their fossil counterpart. No upstream or lifecycle emissions are assumed in this configuration.

Figure 14. Remaining Emissions in 2050 Under Alternative GHG Accounting Frameworks



Stock Rollover Across Pathways

Across scenarios, buildings reach similar levels of emissions reductions using a variety of decarbonization technologies. All mitigation scenarios require rapid adoption of space heating, water heating, cooking, and clothes drying decarbonization technologies in the buildings sector.

Space Heating

In the High Electrification scenario, space heating decarbonization primarily relies upon ASHP and electric boiler adoption, with small levels of networked geothermal. The hybrid scenarios (Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup) both rely upon the same number of hybrid heat pumps/boilers adoption, but with different types of fuel backup (delivered fuels vs. gas). In the Staged Electrification scenario, buildings adopt hybrid heat pumps or boilers in the near term and convert to all-electric in the long term. The Alternative Heat Infrastructure scenario utilizes a combination of hybrid heating and networked geothermal to reach emissions targets. Finally, the Continued Use of Gas scenario depends upon the continued adoption of high-efficiency gas technologies, including hybrid heat pumps/boilers with gas backup.

A breakdown of residential and commercial stock transition and final stock percentages in 2050 can be found in the figures and tables below.

Figure 15. Residential Space Heating Stocks in Rhode Island

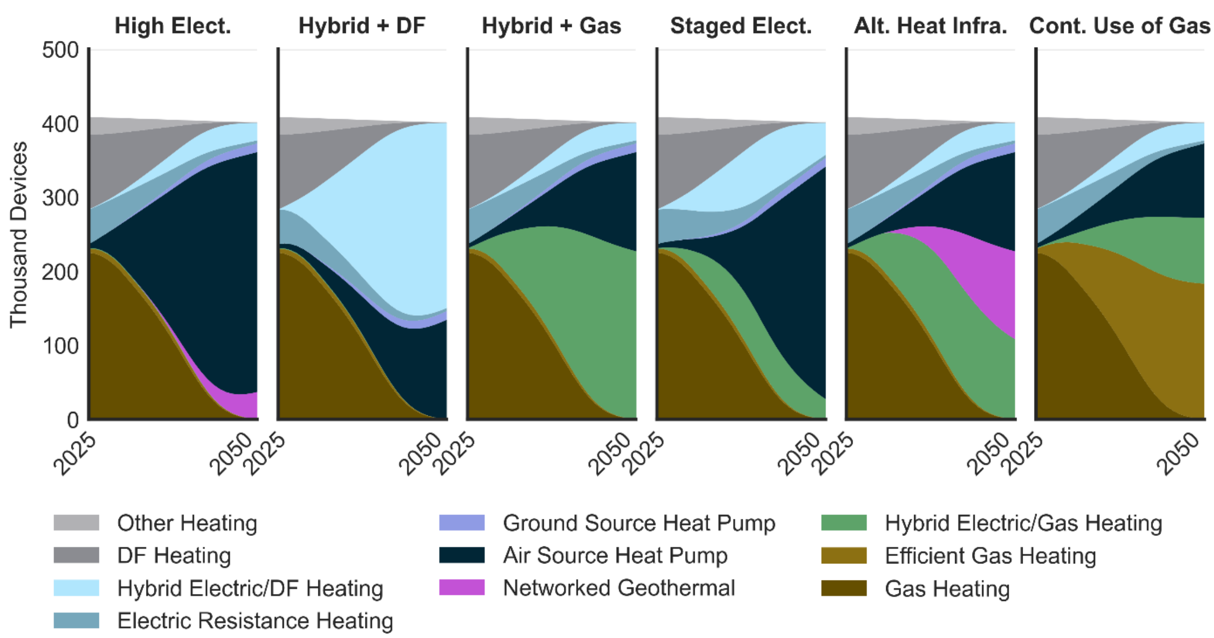
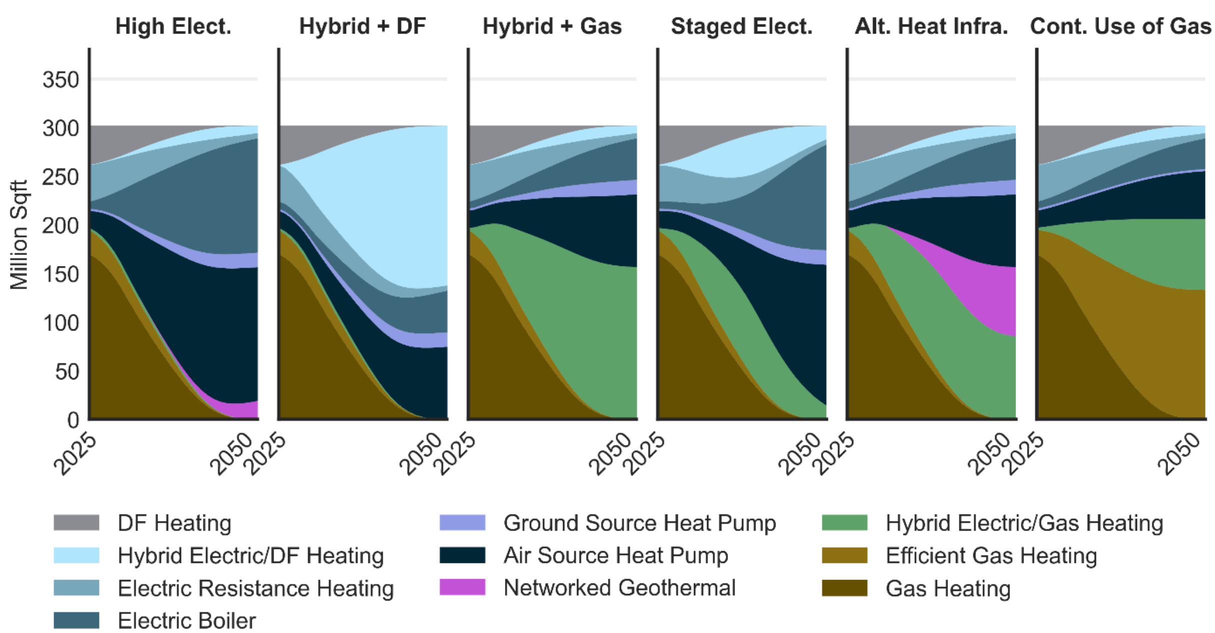


Table 5. Residential Space Heating Stock Breakdown Results in 2050

Technology	High Electrification	Hybrid + Delivered Fuels Back-up	Hybrid + Gas Back-up	Staged Electrification	Alternative Heat Infrastructure	Continued Use of Gas
All Electric HPs	*81%*	*33%*	*33%*	*78%*	*33%*	*25%*
Hybrid Heat Pumps + DF[28]	*6%*	*62%*	*6%*	*11%*	*6%*	*6%*
Hybrid Heat Pumps + Gas	*0%*	*0%*	*56%*	*7%*	*27%*	*22%*
Networked Geothermal	*9%*	*0*	*0%*	*0%*	*30%*	*0%*
GSHPs	*3%*	*3%*	*3%*	*3%*	*3%*	*0%*
Efficient Gas	*0%*	*0%*	*0%*	*0%*	*0%*	*46%*

Figure 16. Commercial Space Heating Stocks in Rhode Island



[28] Note that per discussions with the Stakeholder Committee, for scenarios where hybrid + delivered fuels adoption is not the focus (all except Hybrid + Delivered Fuels Backup and Staged Electrification), the adoption of hybrid heat pumps with delivered fuels backups is kept constant across scenarios.

Table 6. Commercial Space Heating Stock Breakdown Results in 2050

Technology	High Electrification	Hybrid + Delivered Fuels Back-up	Hybrid + Gas Back-up	Staged Electrification	Alternative Heat Infrastructure	Continued Use of Gas
All Electric HPs	*45%*	*25%*	*25%*	*48%*	*25%*	*16%*
All Electric Boilers	*39%*	*14%*	*14%*	*36%*	*14%*	*10%*
Hybrid Heat Pumps + DF[29]	*0%*	*27%*	*0%*	*1%*	*0%*	*0%*
Hybrid Boilers + DF	*2%*	*27%*	*2%*	*4%*	*2%*	*2%*
Hybrid Heat Pumps + Gas	*0%*	*0%*	*27%*	*3%*	*11%*	*16%*
Hybrid Boilers + Gas	*0%*	*0%*	*25%*	*2%*	*17%*	*8%*
Networked Geothermal	*6%*	*0%*	*0%*	*0%*	*24%*	*0%*
GSHPs	*5%*	*5%*	*5%*	*5%*	*5%*	*1%*
Efficient Gas	*0%*	*0%*	*0%*	*0%*	*0%*	*44%*

Space Cooling

In 2020, unlike space heaters, not all residential buildings in Rhode Island had central air conditioning (AC). For modeling purposes, E3 assumed that as global warming continues to worsen and summers become hotter, all households will have AC by 2050. If a building adopts a heat pump for space heating, that same device can be used for space cooling. Therefore, E3 ensured that the number of heat pumps in space heating and space cooling aligned over time to reflect that both types of service demands would be met with the same device. For scenarios with lower amounts of heat pumps, E3 ensured that the same total number of buildings receive AC. That means that in the Continued Use of Gas scenario, for example, an increasing number of households is assumed to adopt central AC over time.

Water Heating

The transformation of water heating stock across decarbonization scenarios was designed to align with the pace of space heating conversions. For example, in the High Electrification scenario, most buildings convert to heat pump water heaters (HPWH) at a similar pace as ASHPs/electric boilers. In the Continued Use of Gas scenario, some buildings convert to HPWHs, but many convert to efficient gas storage water heaters in line with the conversion to efficient gas heating. There are no hybrid water heaters in PATHWAYS; in the hybrid scenarios (Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup), E3 assumed that half of the buildings that adopt a hybrid heating solution in the

[29] Note that per discussions with the Stakeholder Committee, for scenarios where hybrid + delivered fuels adoption is not the focus (all except Hybrid + Delivered Fuels Backup and Staged Electrification), the adoption of hybrid heat pumps with delivered fuels backups is kept constant across scenarios.

space heating sector would adopt a HPWH, and the other half would adopt the combustion equipment based on the same backup fuel as space heating (e.g., gas storage water heater vs. distillate storage water heater). Detailed results for water heating stocks in 2050 are shown below in Table 7 and Table 8.

Table 7. Residential Water Heating Stock Breakdown Results in 2050

Technology	High Electrification	Hybrid + Delivered Fuels Back-up	Hybrid + Gas Back-up	Staged Electrification	Alternative Heat Infrastructure	Continued Use of Gas
HPWH	*98%*	*70%*	*71%*	*97%*	*87%*	*41%*
Efficient Gas Storage	*0%*	*0%*	*20%*	*0%*	*8%*	*42%*
Distillate/Oil Storage	*2%*	*29%*	*0%*	*2%*	*2%*	*2%*
Other[30]	*1%*	*1%*	*9%*	*1%*	*4%*	*16%*

Table 8. Commercial Water Heating Stock Breakdown Results in 2050

Technology	High Electrification	Hybrid + Delivered Fuels Back-up	Hybrid + Gas Back-up	Staged Electrification	Alternative Heat Infrastructure	Continued Use of Gas
HPWH	*78%*	*64%*	*64%*	*76%*	*76%*	*34%*
Electric Resistance Storage	*21%*	*9%*	*9%*	*20%*	*9%*	*22%*
Efficient Gas Storage	*0%*	*0%*	*22%*	*1%*	*12%*	*34%*
Distillate/Oil Storage	*1%*	*27%*	*1%*	*2%*	*1%*	*1%*
Other[31]	*0%*	*0%*	*5%*	*1%*	*3%*	*10%*

Cooking and Clothes Drying

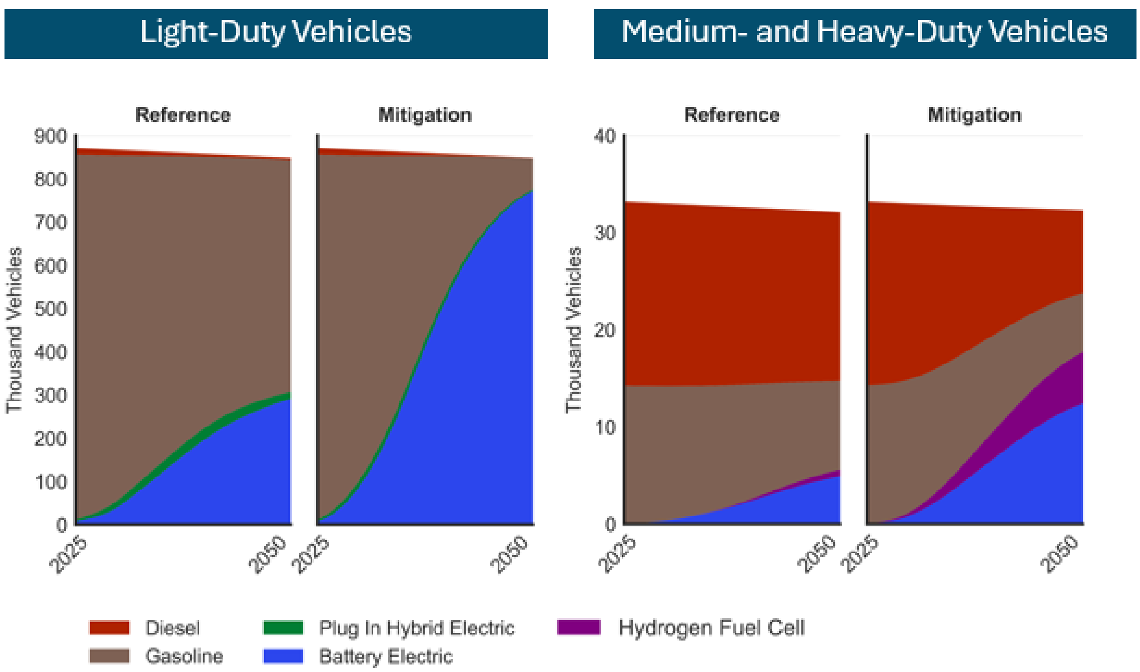
Across all scenarios, cooking and clothes drying subsectors electrify at the same pace as space heating electrification. In this case, hybrid space heating adoption counts as electrification. Therefore, all decarbonization scenarios except for Continued Use of Gas fully electrify cooking and clothes drying, while Continued Use of Gas continues to rely upon a small amount of efficient gas.

[30] Other includes LPG storage, electric resistance, non-efficient gas storage
[31] Other includes Solar, non-efficient gas storage

Transportation

As stated above, LDV and MHDV ZEV adoption across all scenarios is driven by Rhode Island's adoption of ACCII/ACT. The reference scenario assumes that electric vehicle penetration would reach 10% by 2030, as targeted by Rhode Island's Executive Climate Change Coordinating Council (EC4) in the 2022 Climate Update[32], with anticipated penetration primarily driven by current rebate programs, such as DRIVE EV.[33] Results for transportation stock shares for both reference and decarbonization scenarios are shown in Figure 17. Note that the Technical Analysis assumes that the number of vehicles declines as a result of a decline in population, but the VMT per vehicle increases over time.

Figure 17. Stock Rollover in Transportation Sector



Energy Consumption Across Pathways

All scenarios see transformational changes in the way Rhode Island uses energy. Across all scenarios, final energy demand decreases between 40-50% by 2050 as a result of the efficiency and electrification measures discussed in earlier sections.

[32] https://climatechange.ri.gov/media/1261/download?language=en.

[33] DRIVE EV is an electric vehicle rebate project that provides incentives to Rhode Island residents and businesses to adopt electric vehicles. https://drive.ri.gov/.

Figure 18. Economywide Energy Demand Across Scenarios

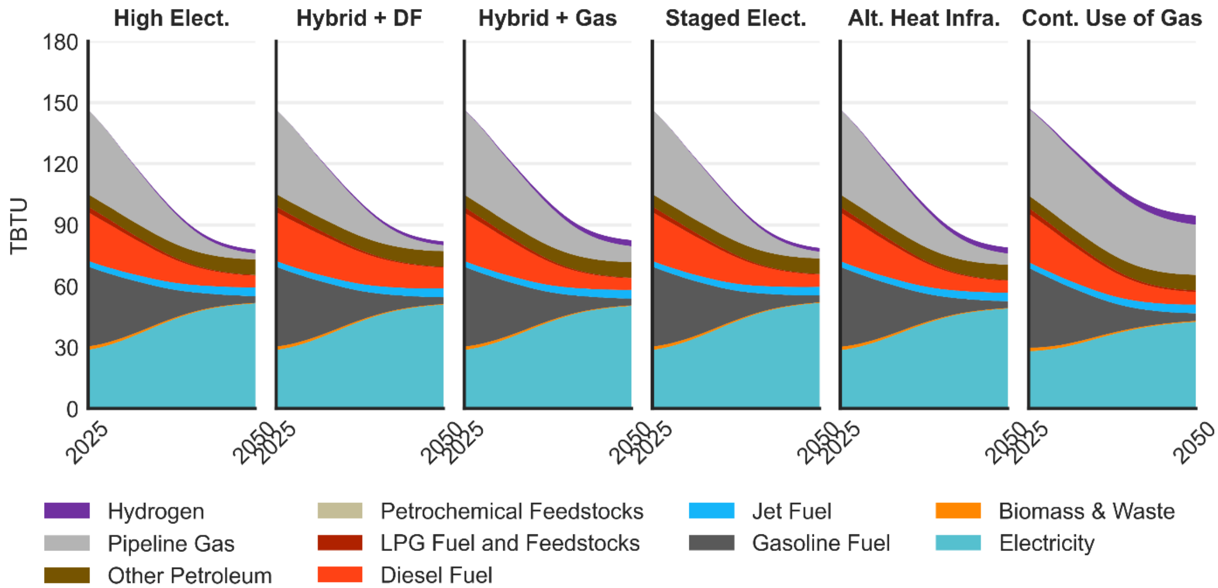
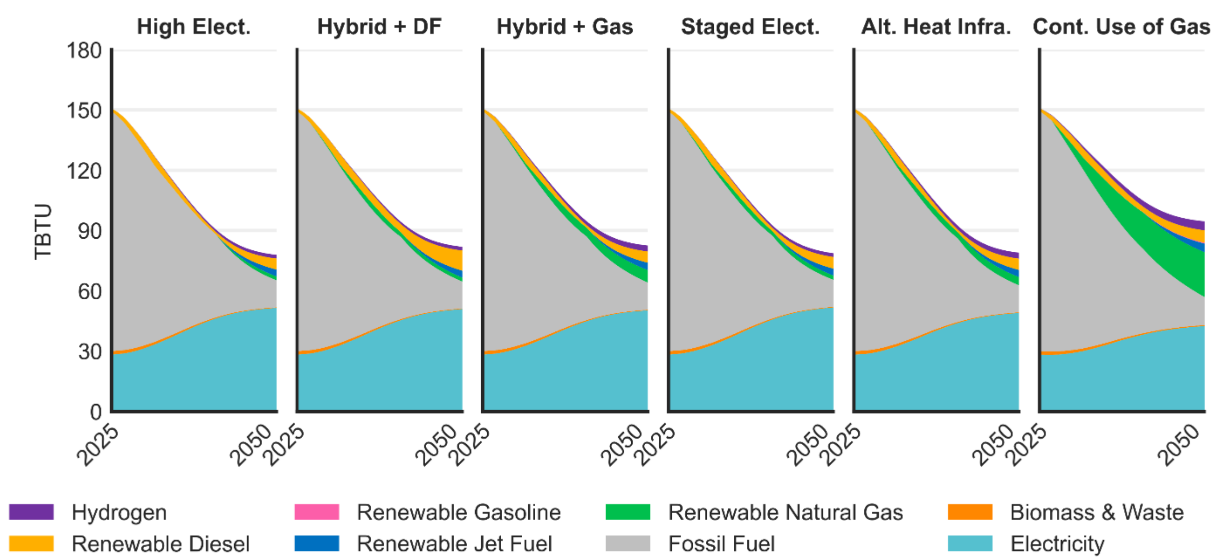


Figure 19. Economywide Energy Demand Across Scenarios (Including Renewable Fuels)

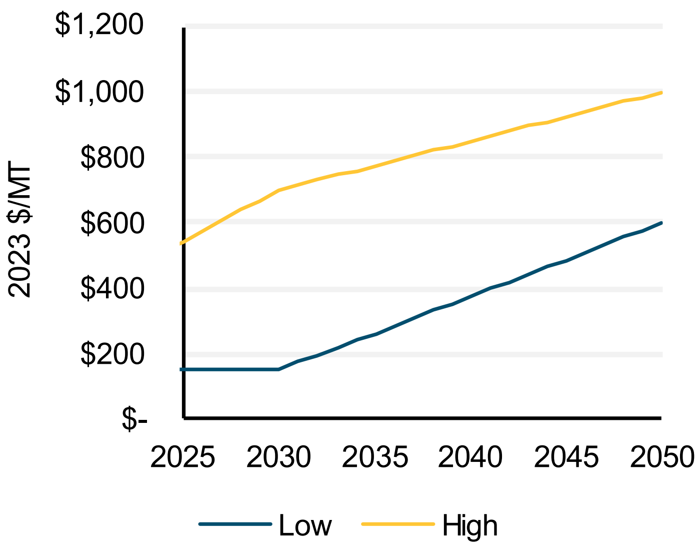


Fuels

Renewable Fuel Attribute Costs

E3 used a simple set of marginal abatement costs across all renewable fuels that represent a compliance cost for the use of renewable fuels over time, bounded by "low" and "high" trajectories. These trajectories were developed with input from the TWG to represent a range of possible attribute costs of renewable fuels that Rhode Island might face in the future, without strictly prescribing or modeling what feedstocks or markets would drive these costs. The cost ranges were assumed to be market-clearing price of abating fuel combustion emissions across all economic sectors. This results in all fuels being subject to the same marginal abatement cost in a given year, regardless of the amount of feedstock used in a scenario.

Figure 20. Marginal Abatement Costs of Renewable Fuels



Shown in Figure 20 and in Appendix B in more detail, the cost trajectories increase from $150/MT in 2023 to $600/MT in 2050 for the low trajectory and $450/MT to $1,000/MT for the high trajectory in the same time frame. Each of these costs were derived using the costs of landfill gas and synthetic natural gas as a proxy, by estimating that landfill gas and synthetic natural gas were the representative fuels providing the marginal unit of carbon abatement in 2023 and 2050 respectively. The costs for landfill gas were assumed to be the opportunity cost of a landfill gas producer not participating in the California Low Carbon Fuel Standard and the US Renewable Fuel Standard markets. In short, the marginal cost is set such that a landfill gas producer is indifferent to selling gas to Rhode Island or to California's transportation sector. The credit prices for these markets were estimated by a review of existing literature on the LCFS and RFS markets. [34] This opportunity cost was assumed to increase the expected revenues for these fuel producers in other renewable fuel markets. Producers of synthetic natural gas were assumed to seek to recover the cost to produce the fuel. Those costs include the cost of dedicated renewable generation, an electrolyzer, direct air

[34] Low Carbon Fuel Standard 2023 Amendments: Standardized Regulatory Impact Assessment. California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf

capture, and a methanator, with non-electricity equipment costs being derived from previous work.[35] The attribute costs were estimated by subtracting out the cost of natural gas.

When applied to an individual fuel i, the final cost c_i was calculated to be equal to the counterfactual fossil fuel f_i plus the market-clearing marginal abatement cost m multiplied by the counterfactual fuel's combustion emission factor e_i: $c_i = f_i + me_i$. Based on this formula, RNG is expected to cost $10-$25/MMBTU more than natural gas in 2023 and $30-$55/MMBTU more in 2050. The cost of delivered fuels, such as renewable diesel, are expected to be higher than the cost of renewable gas because of 1) the higher costs of the fossil counterfactual and 2) the higher emissions factor associated with diesel.

[35] The Challenge of Retail Gas in California's Low-Carbon Future. California Energy Commission. https://www.energy.ca.gov/sites/default/files/2021-06/CEC-500-2019-055-F.pdf

A.2 Gas System Impacts

Gas Revenue Requirement Model Overview

The gas revenue requirement model ("RR model") is a bottom-up model that evaluates the gas revenue requirement and customer rate impacts of each decarbonization scenario. It also calculates the networked geothermal revenue requirement and customer rates for the High Electrification and Alternative Heat Infrastructure scenarios, which include the adoption of networked geothermal systems. The model builds on E3's PATHWAYS model to consider how gas customer and throughput changes in each scenario may impact investment in capital assets, operational expenses, changes in gas volumes, and the cost of renewable fuels to forecast the utility's revenue requirement and customer rates.

The RR model draws on PATHWAYS modeled forecasts of gas throughput and customer count, publicly filed data from RIE, and assumptions determined by the TWG. For each scenario, the RR model outputs:

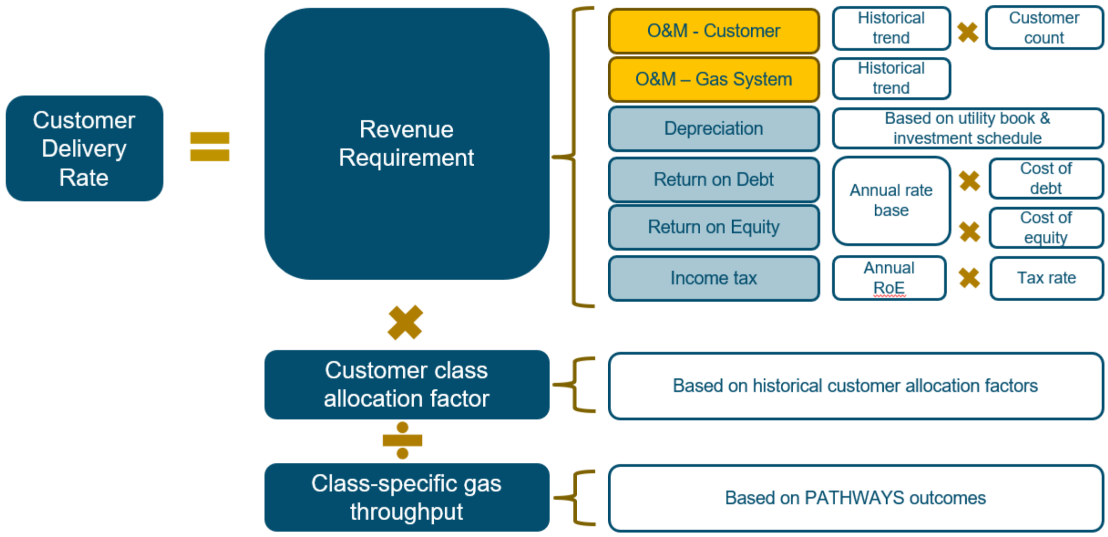
- A forecast of revenue requirement over time, broken out by depreciation, return on capital, income taxes, and O&M expenses.
- Rates by customer class, broken out by gas delivery rate (recovery of the revenue requirement) and gas supply costs (recovery of gas commodity costs and transportation costs).

The RR model also includes sensitivities to explore the impacts of uncertain renewable fuels costs and the opportunity for avoided investments with gas decommissioning under targeted electrification under a "managed transition". These sensitivities are described in greater detail below.

Gas Revenue Requirement Model Design

The RR model calculates RIE's gas revenue requirement through several component modules, primarily a capital accounting module and O&M forecasting module. The model allocates the revenue requirement through dynamic class allocation factors and class-specific gas throughput. Figure 21 provides a schematic of the revenue requirement model. Each component will be explained in greater detail below.

Figure 21. Gas Revenue Requirement Model Framework



Revenue Requirement

Capital Accounting

The core of the RR model is a capital investment and depreciation model that tracks annual investment, depreciation expense, accrual of removal costs, rate base, and return on rate base. In the RR model, capital assets are divided into three categories: Mains, Meters & Services, and Other. The Mains category includes investments in main distribution pipeline, which is largely comprised of RIE's investment in leak-prone pipe replacement. Meters & Services includes investments in service pipeline that directly connects to customers' homes and businesses and the meters that serve these customers. The Other asset category reflects additional, non-pipeline capital investments, such as regulator station upgrades, LNG facilities, and equipment.

The model considers all past investments in capital assets as well as future investments under the pathways scenarios. For investments made prior to 2017, E3 relies on RIE's most recent gas depreciation study and calculates the following attributes:

+ Total original cost ($)
+ Total original removal cost ($)
+ Net book value ($)
+ Annual depreciation expense ($)
+ Annual removal cost ($)
+ Weighted average remaining life (years)
+ Weighted average whole life (years)

The model sums all past investments within the three asset categories and then depreciates those investments over time, with the annual depreciation expense declining over time. The depreciation expense for all prior investments to 2017 is equal to the net book value divided by the weighted average remaining life of the summed investments. The annual depreciation expense of the summed investments declines over time, reflecting that some of the underlying assets will fully depreciate during the period. The total sum of the assets is not fully depreciated until the average whole life of the investments is reached.

For investments made between 2017 and 2022, the model categorizes the historical capital spending filed by RIE into the three asset categories discussed above. Similarly, the model relies on RIE's filed capital spending plans for 2023-2029 to calculate the future investments over this period. The investment in capital assets made after 2017 reflects the vintage of their construction.

After 2029, the model calculates capital asset investments based on assumptions determined by the TWG. These investments can be classified in three ways:

+ **Pipeline replacement investments**: New main, services, and meters are built to replace leak-prone pipe (LPP) that has reached the end of its life. Under the Infrastructure, Safety, and Reliability (ISR) plan, RIE has accelerated its replacement of LPP, and this program is expected to continue through 2035. The model relies on RIE's forecast of LPP main replacement miles and costs until 2035. For mains after 2035 and meters & services replaced after the capital spending plan ends in 2029, the model calculates spending based on the replacement rate and cost assumptions provided in the table below.

Table 9. ISR Pipeline Replacement Count Assumptions

Replacement Type	Number (unit)
ISR Mains (miles)	Varies annually – see Appendix B
Post-ISR Mains (miles)	42
ISR Services (count)	1,512
Post-ISR Services (count)	1,058
Meters (count)	20,000

Table 10. ISR Pipeline Replacement Cost Assumptions

Replacement Type	Cost ($2023)
Steel Pipe Replacement Cost Per Mile	$1,485,000
Iron Pipe Replacement Cost Per Mile	$1,906,000
Plastic Pipe Replacement Cost	$1,695,500
Service Replacement Cost	$6,500
Meter Replacement Cost	$270

- **Other investments and reliability investments**: The model estimates investments in the Other asset category by escalating the previous year's spending by the capital escalation rate. Reliability investments are generally related to main pipeline investments and, as such, are estimated as a percentage of each year's Main capital spending.
- **Customer growth investments**: In scenarios that include an increase in customer connections, such as Continued Use of Gas, the model considers capital investments in Mains and Meters & Services needed to serve those new customers. All new customers are assumed to require a new service line and meter, however only 20% of new customers are assumed to require expanded main lines. The customer connection cost assumptions are provided in the table below.

Table 11. Customer Growth Investment Assumptions

Item	Residential & Commercial
Cost per new customer ($2023)	$8,200
Main growth per new service line	20%
Main line lifetime cost per new customer ($2023)	$2,012

The model tracks depreciation and investment for all assets through 2050. Every year in the model, the annual rate base, depreciation expense, and removal cost accrual are calculated for each category by summing the values for the existing assets and for every vintage of new assets. These values are used to calculate the return on debt, return on equity, and depreciation components of the annual revenue requirement.

Operations and Maintenance (O&M)

O&M in the RR model is based on RIE's historical O&M expenses from 2017-2022 and categorized into Gas System Maintenance or Customer & Admin. A detailed overview of RIE's historical O&M costs is provided in Appendix B. O&M costs are expected to vary year to year, primarily as a result of customer counts. To forecast Gas System Maintenance expenses after 2022, Gas System Maintenance expenses are averaged for the past four years and escalated at the rate of inflation, assuming that in an "unmanaged transition" the gas system needs to be maintained long-term in all scenarios without opportunities to shrink the size of the system. Customer & Admin expenses are forecasted in the same way but also consider customer additions and departures. Customer & Admin expenses are assumed to increase or decrease by a proportional 60% per customer addition or departure respectively, recognizing that O&M expenses are partially dependent on customer count.

Capital Structure

The cost of debt and share of debt are used to calculate the return on debt, and likewise, the cost of equity and share of equity are used to calculate the return on equity. Table 12 shows the weighted cost of capital (WACC) shared by RIE for use in this study.

Table 12. RIE's Capital Structure

RIE's Return on Capital	
Return on Debt	2.42%
Return on Equity	4.73%
WACC	7.15%

Income Tax

The RR model uses a combined state and federal corporate income tax rate of 28%. The income tax component of the revenue requirement is calculated as the tax due on the equity return, grossed up to account for income tax due on the additional revenues. The calculation is provided below – the second component is the "income tax gross-up factor."

$$Income\ Tax = (Equity\ Return\ x\ Tax\ Rate)x\ (\frac{1}{1 - Tax\ Rate})$$

Customer Rates

Gas rates are calculated through three components: the class delivery rate, the gas commodity cost, and rate adders.

Class delivery rate

The class delivery rate reflects the recovery of RIE's revenue requirement (i.e., the cost of the gas distribution system). The model simplifies RIE's customer classes into three broad customer classes: residential, small commercial and industrial (C&I), and large C&I. Delivery rates are calculated by dynamically allocating the revenue requirement to each customer class based on how each classes' share of gas demand changes in each year.

Table 13. Customer Class Breakdown in 2023

Customer Class	% of Gas Customers	% of Gas Throughput	Revenue Requirement Cost Allocation
Residential	90%	50%	67%
Small C&I	9%	28%	20%
Large C&I	1%	22%	13%

RIE recovers a portion of their revenue requirement through a fixed customer charge. For all customer classes, the monthly customer charge escalates at the rate of inflation over time in the RR model.

Gas commodity rate

Gas commodity rates include the cost of natural gas and renewable fuels for a given scenario and the gas transportation costs to a city gate. In the RR model, these costs are estimated on a dollar-per-therm basis. The cost of natural gas is calculated based on a weighted average of the gas prices of three major hubs from which RIE sources its gas – TETCO M2, TETCO M3, TGP Zone 4. E3 develops a near- and long-term forecast for each of these hubs, as outlined in Appendix B. E3 relies on wholesale gas forward contracts for the near-term (2024-2028). For the long-term forecast (2029-2050), E3 uses the EIA's Annual Energy Outlook 2023 annual natural gas Henry Hub price until 2040 and linearly projects the price until 2050. E3 adapts the Henry Hub long-term forecast for RIE's major hubs by adjusting the Henry Hub forecast based on the historical average basis spread from the respective hub to Henry Hub. The renewable fuel costs are described above in the section on Fuels.

Gas transportation costs in the RR model represent the costs incurred by RIE to transport gas from where it is stored or produced to Rhode Island's city gate (i.e., delivery to the local distribution system). The costs are based on RIE's 2022 fixed transportation and storage costs and escalated by inflation over time. Transportation costs are not allocated across customer classes; instead, they are treated as a dollar-per-therm adder to the fuel costs paid by all customers. It is assumed that the total annual transportation costs do not vary by scenario; thus, scenarios with lower throughput are modeled to have higher dollar-per-therm transportation costs.

Managed Transition Sensitivity

To mitigate the customer rate impacts in scenarios with significant gas customer departures, there may be opportunities to manage the transition from gas heating to electrification and avoid some gas system investments as gas customers depart the gas distribution system. E3 explores a potential managed transition by modeling avoided pipeline replacement investments, assuming that geographically targeted electrification would remove the need for these pipes. It is important to note that a managed transition requires coordinated policy efforts and detailed distribution system studies to determine which pipeline can be feasibly retired while maintaining the safety and reliability of the gas system. A managed transition is not yet well studied and there is little evidence for what level of cost reductions may be possible. E3's managed transition sensitivity provides only an illustrative example of the potential gas system avoided costs that could be achieved via a managed transition.

In the managed transition sensitivity analysis, E3 assumes that a maximum of 50% of annual pipeline replacements and their associated capital and O&M costs could be avoided with the number of customer departures in the High Electrification scenario. For all other scenarios, E3 scales down the level of avoided capital spending from pipeline replacements based on the number of gas customer departures relative to the High Electrification scenario. E3 assumes that a managed transition can begin in 2027, assuming a few years of planning is necessary to coordinate such avoided investments.

Networked Geothermal

In addition to the natural gas revenue requirement analysis, E3 developed a networked geothermal revenue requirement analysis as part of the RR model for the High Electrification and Alternative Heat Infrastructure scenarios which include customer conversions to networked geothermal. The networked geothermal revenue requirement similarly assesses capital investments and O&M expenses to determine customer rates. The model assumes that a utility-type of entity would own and operate the networked geothermal system and recover rates independently of the natural gas distribution system, but under the same regulatory structure as the gas system. It is important to note that such a system and regulatory structure have not yet been implemented in the U.S. and would require regulatory approval.

Capital Accounting

The RR model accounts for the installation costs of networked geothermal assets based on the space heating load associated with networked geothermal systems modeled in each PATHWAYS scenario. A dollar-per-ton installation cost, based on Home Energy Efficiency Team (HEET) and BuroHappold's Geothermal Network analysis, is used to calculate the annual capital investment for a networked geothermal system for a given scenario. E3 models an optimistic and conservative bound to networked geothermal costs to explore the uncertainty of this novel technology. These costs only reflect the infrastructure that would be installed and operated by a utility and do not include "behind-the-meter" costs for heating infrastructure that would be installed on customer premises. Similar to gas capital investments, networked geothermal capital investments are depreciated over the lifetime of the assets and the rate base is tracked to calculate the return on debt, return on equity, depreciation expense, and income tax that make up the revenue requirement. E3 uses RIE's gas capital structure as a proxy for investments in networked geothermal systems, but it is important to note that these systems do not necessarily need to be installed by RIE.

O&M

In addition to capital costs, the RR model calculates O&M expenses for a networked geothermal system categorized by System Maintenance and Customer & Admin, similar to the gas distribution O&M expense categories. The System Maintenance expenses are estimated to be 1% of the cumulative networked geothermal capital investment, based on an International Energy Agency (IEA) district heating technology brief.[36] The Customer & Admin expenses are estimated by multiplying an average per-customer O&M cost, based on the gas distribution system Customer & Admin costs, by the total number of networked geothermal customers. This approach assumes that the networked geothermal system will incur similar customer-related O&M costs as the gas distribution system.

Customer Rates

Networked geothermal costs are fully recovered through fixed delivery rates that recover a utility's revenue requirement. Networked geothermal customer rates do not include a volumetric component as there is no commodity cost associated with the delivery of heat. The networked geothermal customer charge is estimated by allocating the networked geothermal revenue requirement between residential and commercial networked geothermal customers and dividing the allocated revenue requirement by the number of residential and commercial networked geothermal customers. It is important to note that other methods of cost allocation for networked geothermal systems may be possible that are not studied in the Technical Analysis.

Key assumptions used to calculate the networked geothermal revenue requirement are provided in Table 14.

Table 14. Networked Geothermal Key Assumptions

Input	Assumption	Data Source
Capital Cost ($/ton) – provided in Appendix B	$15.1k-$24.5k (single family) $8.3k-$13.5k (multifamily & commercial)	Home Energy Efficiency Team and BuroHappold's Geothermal Networks Feasibility Study (2019)
O&M System Maintenance Costs (% of capital investment)	1%	IEA (2013), District Heating Technology Brief
Average O&M Customer & Admin Costs ($/customer)	$377	Calculated value, based on average gas customer O&M cost
Asset Lifetime (years)	55	Calculated value, based on average whole life of gas assets

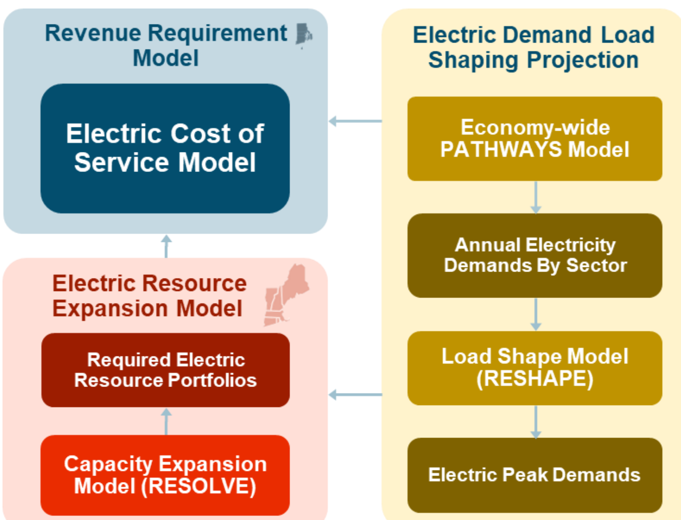
[36] IEA Energy Technology Systems Analysis Program. January 2013. District Heating Technology Brief. https://iea-etsap.org/E-TechDS/PDF/E16_DistrHeat_EA_Final_Jan2013_GSOK.pdf

A.3 Electric System Impacts

Electric system impacts in Rhode Island are modeled through projections of future electric demand and resource portfolios, consisting of three components:

- **Electric Load Shaping** calculates how peak demands change under various scenarios based on annual energy sales projections from the PATHWAYS model, providing load inputs to the Revenue Requirement Model and the Resource Expansion Model.
- **Electric Resource Expansion Modeling** projects future electricity resource portfolios and costs, providing inputs of future generation cost changes to the Revenue Requirement Model. This model takes into account the entire ISO New England (ISO-NE) system.
- **Electric System Revenue Requirement** starts from total cost of generation and non-generation service today and projects future changes of the costs based on changes in resource requirements.

Figure 22. Electric Systems Impacts Modeling Framework



Load Shaping

Overall Process

E3 produced hourly loads for Rhode Island across 40 weather years spanning 1979 to 2018. E3 used unique load shapes for the following load categories:

- Residential and commercial space heating (see “Building Heating and Cooling” below);
- Residential and commercial space cooling (see “Building Heating and Cooling” below);
- Residential and commercial water heating (see “Building Heating and Cooling” below);

- Light-duty vehicles;
- Medium- and heavy-duty vehicles.

All other loads, such as residential or commercial cooking or industrial heating loads, were assigned to a baseline shape consistent with the historical Rhode Island hourly loads prior to the modeling period. Note that any existing loads from those above unique categories were shaped using the baseline shape. Only new, incremental loads within these categories were shaped using their unique, explicit load shape.

For light duty vehicles, E3 applied the same shape as used in the Massachusetts 20-80 Future of Gas proceeding. [37] These shapes account for potential managed charging through LDV flexibility assumptions, which are documented in the accompanying data appendix. Medium- and heavy-duty vehicles were assumed to have a constant, flat shape. While vehicles within these classes display a variety of driving and charging patterns, their contributions to peak load were assumed to be small due to their limited relative electrification potential.

Once hourly loads were determined across all 40 weather years for a given model year, a distribution of both 40 coincident and noncoincident summer and winter peaks were calculated. The median (or 50/50) coincident and the 1-in-10 (or 90/10) noncoincident peaks were determined for each season from the previously determined distribution. The final statistical peaks were selected by choosing the largest of the respective seasonal peaks. This process was repeated for model year 2020 and every five model years afterwards. The 2020 median seasonal coincident peaks were benchmarked to Rhode Island's 2020 seasonal median coincident peaks.

Load flexibility

In this study, flexible load refers to load that can be shifted to another time in the day. Daily and hourly shiftable loads are calculated by assuming that portions of EV charging, water heating, and space heating loads are flexible and can be distributed across the day in order to mitigate peak impacts. It is likely to assume that these types of flexible loads will be driven by alternative rate structures, such as Time of Use (TOU) rates.

E3 modeled load flexibility by decreasing the contribution of a given load contribution by a simple load flexibility parameter, multiplied by the load flexibility participation rate. An overview of key load flexibility assumptions is provided in the table below, as well as in Appendix B.

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[37] The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals: Technical Analysis of Decarbonization Pathways. Energy and Environmental Economics, Inc. https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Decarbonization%20Pathways.pdf.

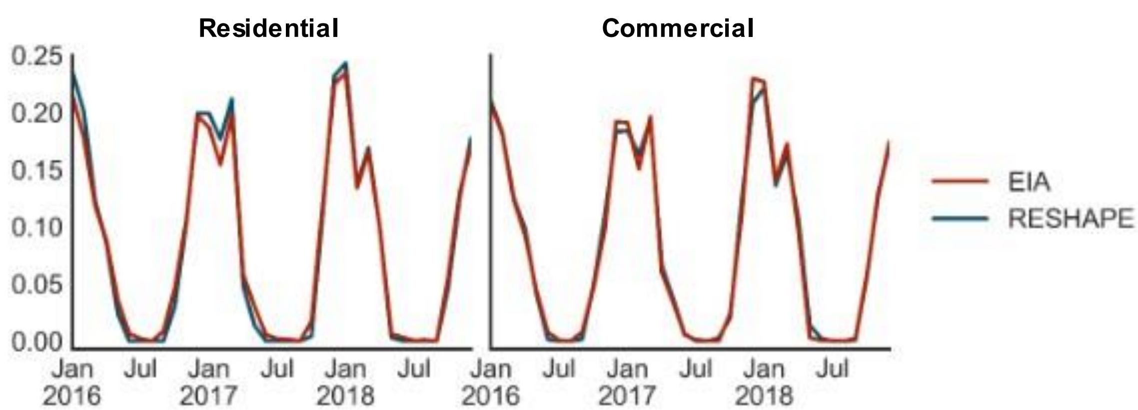
Table 15. Load Flexibility Assumptions

Load flexibility component	Percentage
Fraction of daily energy budget that can be dispatched within 1 hour	4.6%
Maximum per-participant percent of residential and commercial coincident water heating peak that are shiftable	100%
Maximum per-participant percent of residential and commercial coincident space heating peak that are shiftable	20%
Maximum per-participant percent of light-duty EV charging peak that are shiftable	50%
Residential and commercial space and water heating load flexibility participation	25%
Light-duty EV charging flexibility participation	100%

Building Heating and Cooling

RESHAPE was designed by E3 to simulate heat pump operations given sensible space heating, space cooling, and water heating demands in a variety of building typologies across the residential and commercial building sectors. Using these simulations, RESHAPE produces 40 historical weather years (1979-2018) of shapes for these subsectors.

Figure 23. EIA/RESHAPE Seasonal Unitless Gas Demand Shapes.

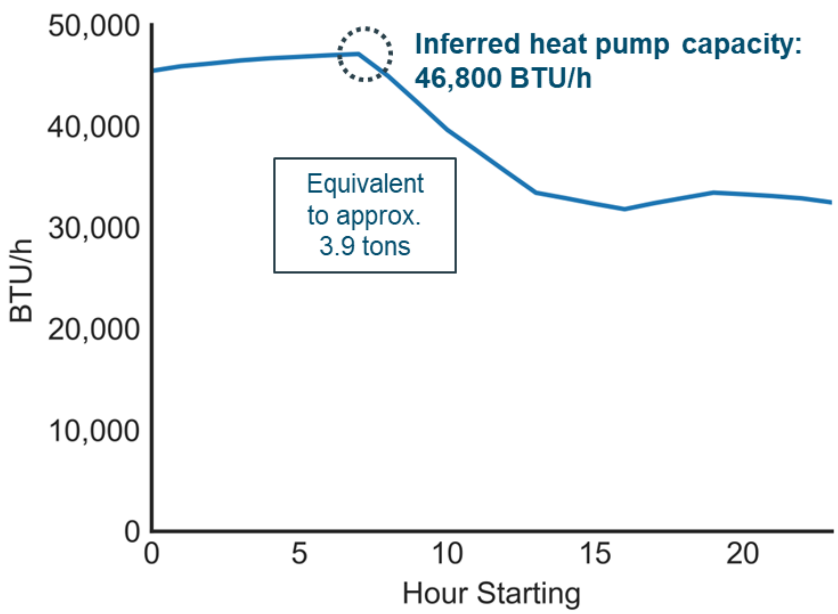


RESHAPE's sensible space heating demands were benchmarked to replicate the seasonality of monthly residential and commercial gas sales as reported by the US Energy Information Administration (EIA) in Rhode Island from 2016-2018. By using this benchmarking approach, E3 assumed that seasonal gas sales are representative of the seasonality of space-, and to a lesser extent water-, heating. Furthermore, because gas space heating appliance efficiencies are largely insensitive to temperature, E3 assumes that the seasonal gas throughput is representative of sensible heat demand. As shown on Figure 23, E3's simulated sensible heating demand shape and the shape derived from EIA datasets align well across the three weather years used for benchmarking. A similar benchmarking process was carried out to produce space cooling shapes.

Service Demands and Heat Pump Sizing

Using the outputs from RESHAPE, E3 estimated the sizing of whole-home and hybrid heat pumps in Rhode Island. The value of RESHAPE's sensible space heating hourly demand shapes for each heat pump type were estimated at their design temperatures of 10˚F (whole-home) and 25˚F (hybrid). These shapes are multiplied by the heating service demand for a given building type in PATHWAYS and are scaled by a factor 120% to ensure that the heat pumps are appropriately sized at design temperature.

Figure 24. Single-Family Whole-Home Heat Pump Compressor Heating Demand



The result of this analysis is shown above in Figure 24. for a whole-home heat pump sized for a typical single-family home on a design day. At the design hour, indicated by the circle, the heat pump must be able to supply about 3.9 tons of heating. When scaled by 120%, this resulted in the 4.5 ton heat pump used across several components of this study.

Electric Resource Expansion Modeling

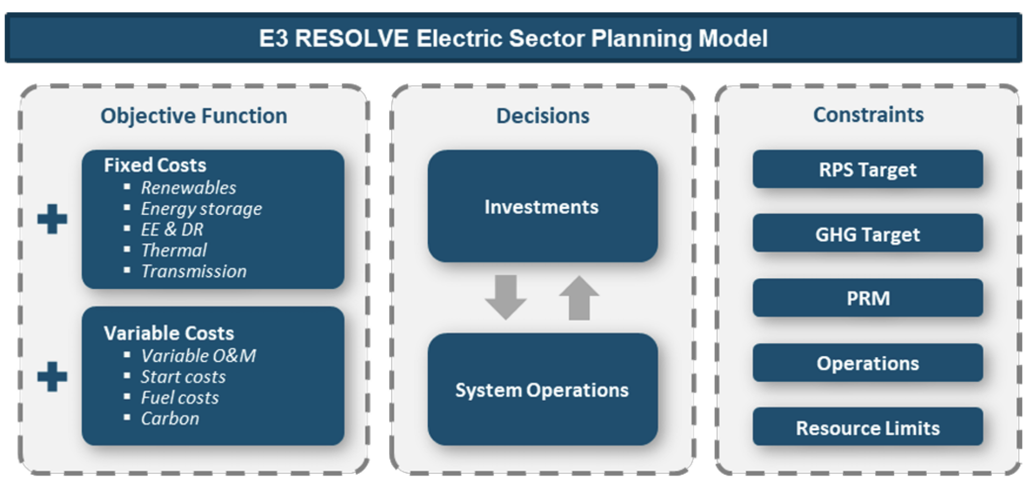
E3 applied the New England RESOLVE capacity expansion model in this study to model generation resource requirements and cost across the ISO-New England (ISO-NE) area. ISO-NE was modeled in its entirety because of the connectedness and interdependence of Rhode Island in the regional ISO-NE electricity market.

Figure 25 provides an overview of E3's RESOLVE model. RESOLVE models the resource needs and cost of generation, as well as transmission expansion needed, to meet the electric demand in ISO-NE, subject to renewable targets, greenhouse gas emissions reduction targets, planning reserve margin requirements, and other constraints. In addition to generation costs, new transmission costs are modeled endogenously in RESOLVE considering renewable interconnection, and regional network upgrade above existing headroom to connect resource builds.

In this study, RESOLVE optimizes for least-cost future electric resource portfolios across the entire ISO-NE using the following four key constraints:

+ **100% Renewable Energy Standard (RES) in Rhode Island by 2033, and existing renewable portfolio standards (RPS) for all New England states** reaching a region-wide weighted average of approximately 50% RPS by 2050, serving as a floor for future renewable builds.
+ **Latest offshore wind mandates** in Massachusetts (5.6 GW by 2027) and Rhode Island (600-1000 MW by 2030).
+ **Electric-sector GHG reduction by 90+% by 2050 consistent with achieving economy-wide net zero emissions in New England by 2050**, likely driving renewable penetration needs beyond the RPS requirements.
+ **ISO New England's reliability standard** to plan resources towards 1-day-in-10-year loss of load event to ensure the future electricity system remains its reliability according to current-day industry standards.

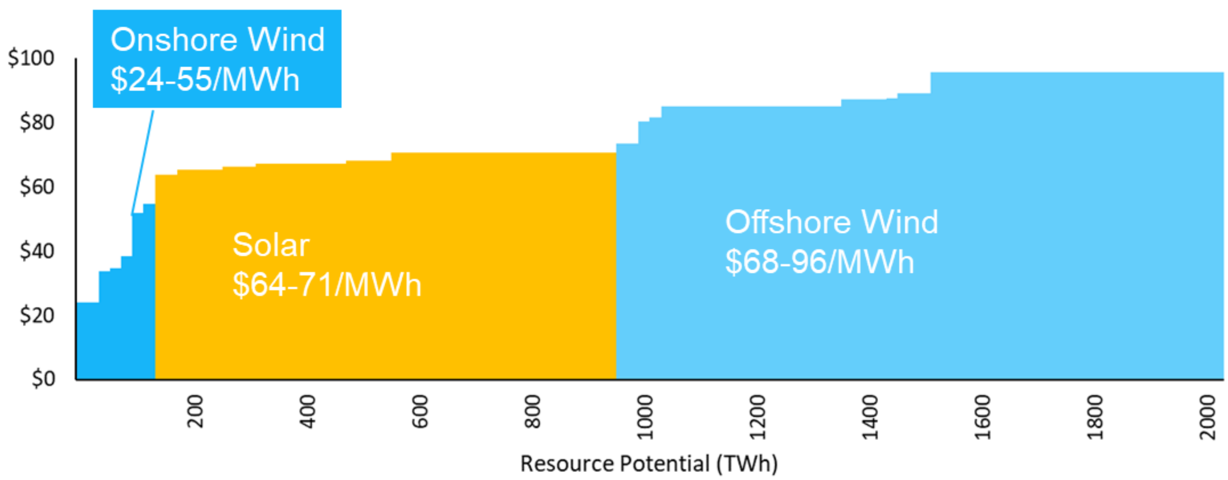
Figure 25. Overview of E3's RESOLVE Model



Generation costs were scaled down to Rhode Island using the state's share of annual electric demand in ISO-NE. A cost generation adjustment was applied to account for the gap between the average renewable generation share of approximately 60% achieved in New England and Rhode Island's 100% RES by 2033, to account for the fact that Rhode Island will likely need to buy more expensive resources to comply with the stringent RES. E3's modeling framework assumes that the gap will be met via purchases of Renewable Energy Certificates (RECs). REC prices are represented in two bounding scenarios with $31/MWh on the low end and $51/MWh on the high end, consistent with historical trend of MA Class I REC prices and the current incremental cost of renewable generation, as well as reflecting potential future changes under state policies and renewable market prices.

A critical input to RESOLVE is the assumption on renewable cost and potential. Renewable resource costs used in this study are based on recent versions of NREL Annual Technology Baseline and industry trends. Resource costs include effects of the recent market trend of increased renewable prices due to supply chain disruptions, and federal tax credit impacts from the Inflation Reduction Act of 2022 (IRA). Figure 26 shows the renewable cost and potential inputs to RESOLVE in a renewable supply curve across ISO New England. Overall, onshore wind is the lowest-cost renewable resource but with limited potential subject to available of land, followed by solar and offshore wind. A detailed overview of resource costs is provided in Appendix B.

Figure 26. ISO New England Renewables Supply Curve

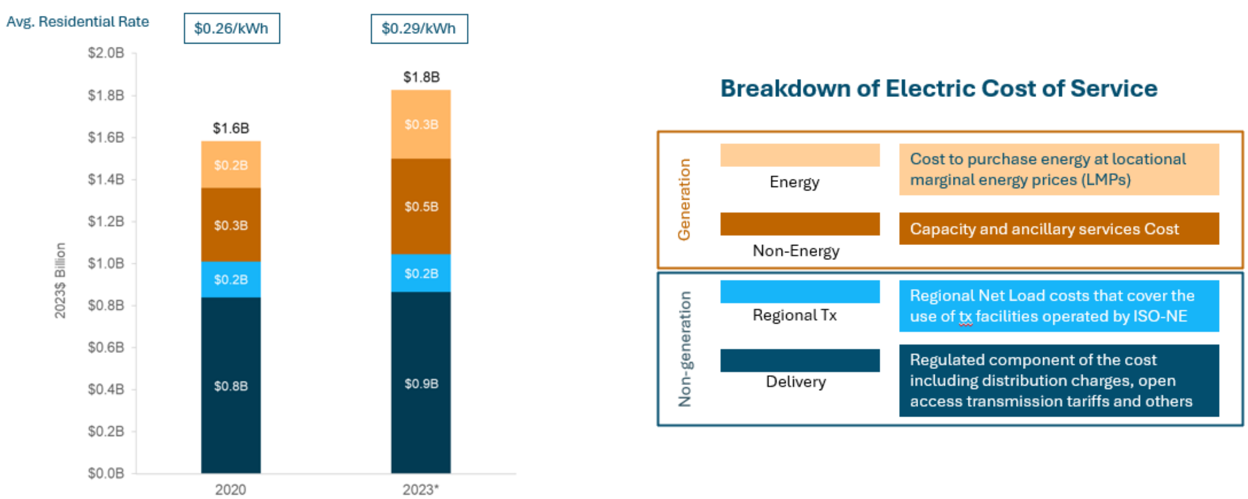


In addition to renewables, other clean resources were modeled for their critical roles to help achieve deep GHG reductions in the electric sector. Li-ion battery storage with 4-hour duration was modeled and its costs benchmarked to recent market trends showing upfront cost of approximately $1,500/kW. Battery storage provides both capacity values and facilitate the integration of variable renewable resources/ Li-ion battery costs almost doubled compared to 2021 reflecting increasing raw material costs and supply chain disruptions. Nuclear small modular reactors (SMR) were modeled as a clean firm resource option with upfront cost of approximately $9,000/kW. As an emerging technology, SMR was only modeled as an option after 2030. Hydrogen was modeled as a low-carbon fuel option to be blended with natural gas for combustion turbines. Hydrogen was also modeled as available after 2030 only.

Electric System Revenue Requirement

In modeling projected electric system revenue requirement for the Rhode Island system, E3 first analyzed the total cost of generation and non-generation services today and benchmarked the costs to current average electricity rates. As shown in Figure 27, total electric cost of service grew from approximately $1.3 billion in 2020 to $1.5 billion in Rhode Island in 2023, estimated based on historical sales data from the US Energy Information Administration. One-third of the electric cost are spent on generation, while two-thirds of the costs are on transmission and distribution to bring electricity to customers. E3 developed the breakdown of the cost into four cost components based on wholesale load prices reported by ISO New England, delivery rates based on Rhode Island Energy's rate case filings and historical sales data. Wholesale load cost was broken into energy, non-energy and regional transmission (Tx) costs is based on locational marginal energy prices, capacity and ancillary services prices and regional net load prices reported by ISO-NE in the ISO-NE annual report.

Figure 27. Breakdown of Current Electric System Revenue Requirement in Rhode Island



* Breakdown of 2023 revenue requirement by component is estimated based on 2020 data and recent market trend as 2023 data were not available.

E3's Electric Revenue Requirement Model projects future changes in the costs of electricity in Rhode Island considering both electric resource expansion and transmission and distribution investments. Table 16 shows the main drivers of changes in revenue requirement cost components. Generation costs are modeled in RESOLVE considering variable cost of generation, fixed cost of generation for existing resources that may retire over time, and fixed cost of generation for new resources mainly from building new renewables and clean firm resources. Non-generation costs are modeled separately, with the exception of the transmission expansion costs modeled endogenously in RESOLVE. Existing non-generation costs for current transmission and distribution infrastructure are assumed to increase based on historical trend from 2017 to 2021 at approximately 1.2% per year as a starting point and at a slower rate over time until no increase beyond 2030. This is to account for any near-term non-load increase related upgrades, such as those related to grid modernization. New distribution system upgrade costs were modeled at ~$0.25 Million per MW_peak based on incremental 1-in-10 peak demand as a starting point, informed by RIE's Grid Modernization Plan. The distribution upgrade costs assumptions increased over time to approximately $1.3 Million per MW_peak by 2030 informed by RIE's Non-Wire Alternative (NWA) study, reflecting increasing cost to build new distribution capacity as current system head rooms are depleted as electrification levels increase.

Table 16. Drivers of Changes in Revenue Requirement Cost Components. Arrows Showing Directions of the Changes across All Scenarios.

Drivers of Generation Cost Changes		Drivers of Non-generation Cost Changes	
Variable cost of generation including fuels, variable O&M, and market purchases	↓	**Existing non-generation costs** for current T&D infrastructure	↑
Fixed cost of generation for existing resources that may retire over time	↓	**New investment in T&D infrastructure** to meet increasing peak demand	↑
Fixed cost of generation for new resources including new renewables and other clean resources to meet clean electricity targets and new capacity resources to meet increasing peak demand	↑		

A.4 Total Resource Costs and Affordability Impacts

Economywide Cost Model Overview

E3's Economywide Cost Model is designed to calculate the incremental total resource cost (TRC) for each scenario in $2023, relative to a reference scenario. The TRC calculation within the model accounts for all energy-related decarbonization costs including demand-side capital costs incurred by Rhode Island residents, such as appliance purchases, as well as energy infrastructure and fuel costs. The model incorporates results from E3's PATHWAYS Model, Gas RR Model and Electric RR model to develop a TRC and enable comparison of the economic viability of decarbonization strategies that comply with Act on Climate targets. A full list of cost components calculated within the Economywide Cost Model is provided in the table below and a detailed description of how each cost component is calculated is provided in the following subsections.

Table 17. Total Resource Cost Components

Cost Component		Includes
Demand-side capital	Appliance / equipment	All consumer appliance/equipment costs (vehicles, space heating, water heating, building shells, etc.)
	Rebates / incentives	Federal rebates/incentives for consumer appliance/equipment costs (vehicles, space heating, etc.). State rebates/incentives are excluded as they are both collected and distributed in Rhode Island and are assumed to result in a net impact of zero
Electric system		Electricity system costs for generation, transmission & distribution
Gas system		Costs for gas distribution (annual revenue requirements) and transmission supply
Networked Geothermal system		Installation costs of the Networked Geothermal system (note: additional behind-the-meter customer conversion costs are included in demand-side capital costs)
Fuels	Natural gas	Commodity costs for natural gas
	Renewable gas	Commodity costs for zero carbon gases (e.g. hydrogen, SNG, biomethane)
	Fossil fuels	Commodity costs for other fossil fuels
	Liquid renewable fuels	Commodity costs for imported renewable fuels

Cost Component Calculations

- **Demand-side Capital Costs.** Levelized costs are calculated for all demand-side purchases including vehicles, space heating, water heating, air conditioning, building shells, cooking, lighting, etc. The model first estimates an "overnight" capex by multiplying annual equipment sales from the PATHWAYS Model by their associated equipment cost forecast. Overnight capex is then levelized using a financing rate of 5% and an average financing period of 10 years. The model includes two equipment cost forecasts for each type of equipment. These two forecasts are used to calculate the "low" and "high" cost sensitivity for this cost component.

  Federal rebates and incentives are also accounted for within the model. Rebates and incentives include IRA heat pump tax credits, high efficiency electric home rebates, home energy performance-based whole-house rebates, energy efficiency home improvement credits, commercial energy efficiency tax deductions, the clean vehicle credit, and the commercial clean vehicle credit. The model assumes that 20% of the residential population access tax credits for applicable equipment purchases, based on Census income data for Rhode Island and IRA guidance. Within the model, tax credits phase out in 2033 or 2032 depending on the program. For rebates, the model assumes that Rhode Island residents receive the state's full share of funding ($51.2 million across rebate programs)[38]. Rebate cost impacts are spread out over time based on equipment purchases.

- **Electric System Costs.** The Economywide Cost Model uses the electric revenue requirement produced by the Electric RR model to estimate annual electric system costs (see section A4 above for additional detail). The Electric RR model produces a "low" and "high" electric revenue requirement that is directly used as the annual electric system cost component in the model. The revenue requirement data input into the model is segmented into variable generation, fixed generation, incremental generation capacity, and incremental transmission and distribution costs.
- **Gas System Costs.** The Economywide Cost Model uses the gas revenue requirement produced by the Gas RR model to estimate annual gas system costs (see section A3 above for additional detail). The Gas RR model produces a "base" and a "managed transition" gas revenue requirement that is directly used as the annual gas system cost component in the model. "Base" is an estimate of the revenue requirement for each scenario under current regulatory and policy structures. "Managed transition" is an estimate of the revenue requirement for each scenario where reductions in customer count result in avoided gas investment and operating costs.
- **Geothermal System Costs.** The Economywide Cost Model uses the networked geothermal revenue requirement produced by the Gas RR model to estimate annual networked geothermal system costs (see section A3 above for additional detail). The Gas RR model produces a "low"

[38] Advanced Energy United. *Making the Most of Federal Home Energy Rebates*

and a "high" networked geothermal revenue requirement that is directly used as the annual networked geothermal cost component in the model.

- **Fuel Costs.** Fuel costs are calculated for all fuels across all sectors of the economy including hydrogen, natural gas, diesel, LPG, wood, gasoline, coal, kerosene, fuel oil, etc. Annual fuel costs are estimated by multiplying annual energy demand from the PATHWAYS Model by the sum of the fuel commodity cost forecast and any applicable renewable fuel attribute costs (see equation below). The model estimates the cost of renewable fuel attributes based on the blend of zero-carbon fuel identified by the PATHWAYS Model. The model includes two cost forecasts for renewable fuel attributes (see section A2 for additional detail). These two forecasts are used to calculate the "low and "high" cost sensitivity for this cost component.

$$f = v * (1-b) * m + v * b * (m + a)$$

Where f represents the annual economywide cost for a given fuel, v is the demand for that fuel, b is the zero-carbon fuel blend for that fuel, m is the commodity cost for that fuel, and a is the renewable fuel attribute cost.

Overarching Modeling Approach

The Economywide Cost Model does not conduct a Societal Cost Test (SCT). Thus, the model excludes the impact of externalities such as air quality improvements, the value of avoided carbon, or workforce impacts.

Costs within the model are estimated on an incremental basis compared to the reference scenario. Thus, for each decarbonization scenario, the model nets out the costs of a reference scenario in which decarbonization targets are not met (see equation below). Therefore, all outputs from the model are presented on an incremental economy-wide cost basis. This approach is designed to isolate the effects of decarbonization on energy system costs and avoid issues associated with costing equipment turnover before the study period. This approach to costing does not identify how costs would be paid for or allocated. Rather, this approach provides a high-level economy-wide perspective that can be used as a comparison point between mitigation scenarios.

$$c = (d_m + e_m + g_m + n_m + f_m) - (d_r + e_r + g_r + n_r + f_r)$$

Where c represents incremental annual economywide costs, d is levelized demand-side capital, e is annual electric sector costs, g is annual gas sector costs, n is annual network geothermal system costs, f is annual fuel costs, and the subscript $_m$ and $_r$ represent mitigation versus reference scenario.

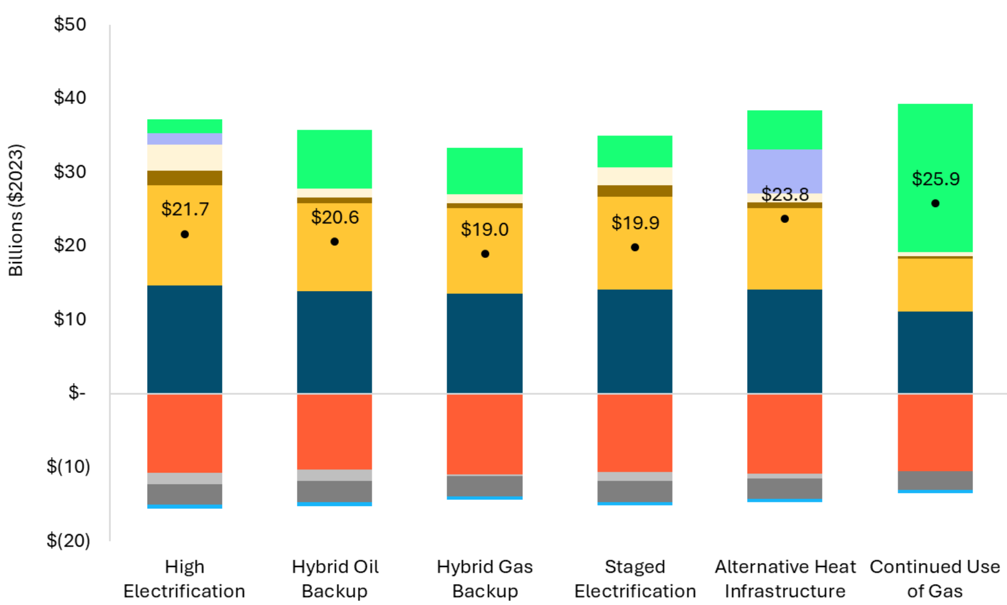
The model calculates both an annual and cumulative net present value (NPV) incremental TRC. To do so, the model utilizes a combination of sector-specific financing rates and a single societal discount rate that is applied economywide. Sector-specific financing rates are used to calculate annual costs for cost components that require investment. They do so by levelizing the cost of an investment over the investment's timeframe. A financing rate is not applied to fuel costs, as they are incurred annually and do not require upfront investment. Once annual costs are estimated for each cost component, the societal discount rate is then applied. The purpose of the societal discount rate is to convert results into net present value. The societal discount rate used within the model is 1%. The societal discount rate was informed by TWG feedback and is meant to ensure that scenarios that delay costs, and therefore place burden on future generations, and not unintentionally favored.

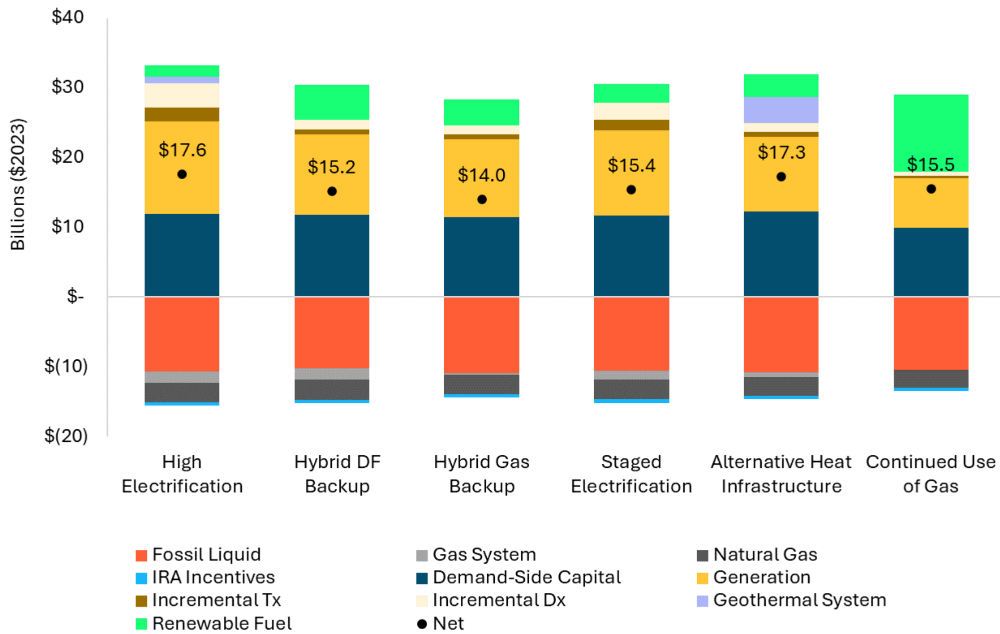
The Economywide Cost Model estimates incremental TRCs across a set of sensitivities including "low" and "high" cost assumptions as well as the cost impact of a managed gas transition. Low and high cost trajectories are included in the model for the majority of cost components and mirror the sensitivities established in the PATHWAYS Model, Gas RR Model, and Electric RR Model. Low represents a low-bound trajectory for a given cost component found across literature, while high represents a high-bound trajectory. These cost assumptions were developed to capture the range of uncertainty for cost categories, including uncertainty regarding the future cost of renewable fuels, electric appliances and vehicles, as well as electric and gas system investments. Additionally, the model is designed to estimate the cost impact of a managed transition on gas infrastructure and demand-side capital costs. A full set of low and high cost trajectories and sources can be found in Appendix B.

Cumulative Cost by Component

The figure below shows the cumulative (2023-2050) NPV costs by component for all scenarios.

Figure 28. Cumulative TRC Across Scenarios. Top: High-Bound Input Assumptions, Bottom: Low-Bound Input Assumptions

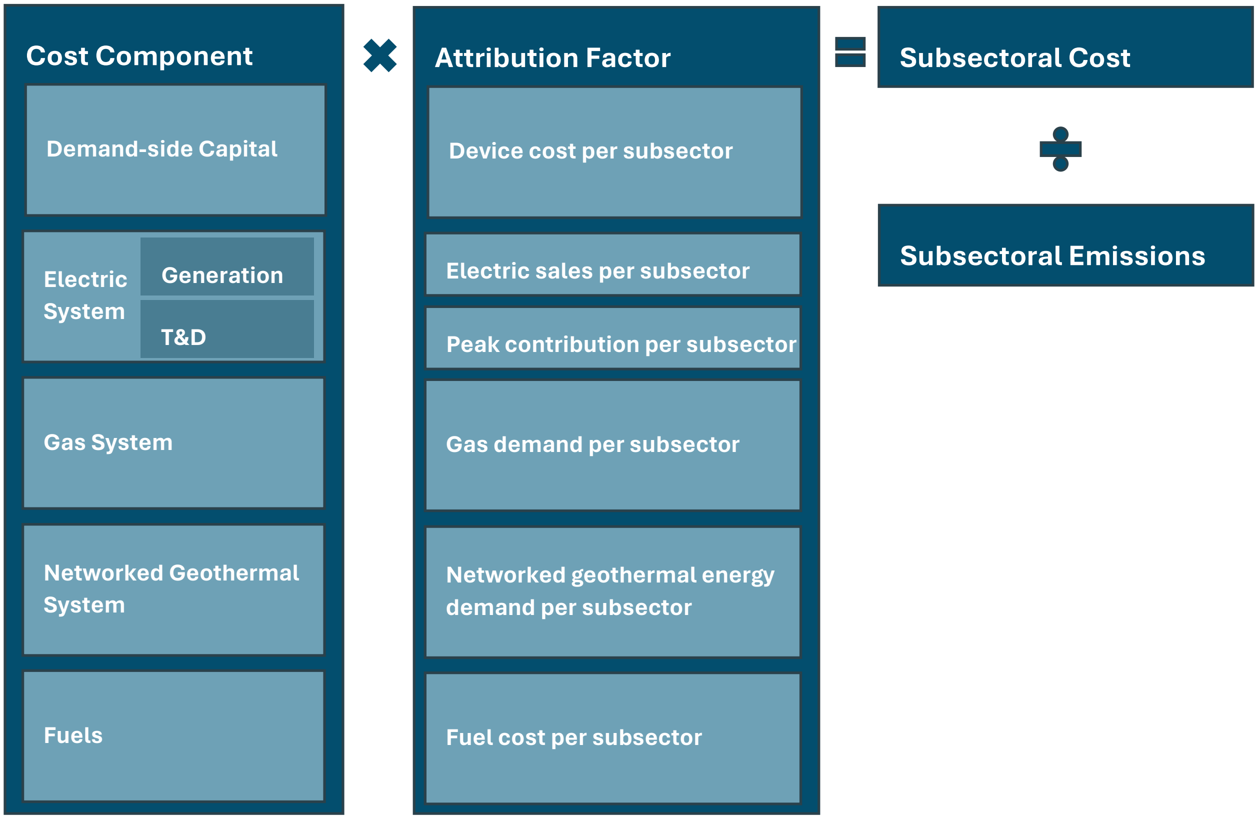




Subsectoral Abatement Cost Analysis

The Economywide Cost Model is designed to produce a subsectoral abatement costs for all scenarios and sensitivity combinations. The calculation involves first estimating subsectoral costs for each cost component and dividing the result by an estimate of subsectoral emissions (see the figure below).

Figure 29. Subsectoral Abatament Cost Framework



Economy-wide costs are broken out by subsector based on cost-component attribution factors developed for each subsector. Attribution factors are established for each cost-component based on the major cost driver of each cost component. For example, transmission and distribution costs are expected to be largely driven by load, therefore the attribution factor used to allocate transmission and distribution costs across subsectors estimates each subsectors contribution to load and allocates costs accordingly. Emissions are broken out by subsector based on the energy demand of each subsector. Subsector energy demand is provided as a PATHWAYS output. Fuel-specific emissions factors are applied to the mix of fuel associated by each subsector. Electric emissions factors are applied to the MWh of electricity associated with each subsector.

Uncertainty Analysis

The Economywide Cost Model conducts an uncertainty analysis based on the "low" and "high" incremental TRCs calculated for each mitigation scenario. The uncertainty analysis conducted by E3 is based on Regret Analysis from Decision Theory.[39] Leveraging the regrets analysis framework, E3 has defined "uncertainty" as the extra cost of a given scenario above the lowest cost scenario within each sensitivity. Therefore, an uncertainty of zero indicates that the scenario was the lowest

[39] Peterson M. *An Introduction to Decision Theory.* Cambridge University Press, 2013.

cost scenario within that sensitivity. The uncertainty analysis highlights scenarios that are particularly sensitive to cost uncertainties.

A set of sensitivity combinations is used to perform the uncertainty analysis, the first of which sets all cost components to “low” for all scenarios. One cost component at a time is then changed to “high” for all scenarios. In addition, the uncertainty analysis includes a sensitivity combination where all cost components are set to “low” and a managed transition is turned “on”. For each sensitivity combination, the scenario with the lowest NPV incremental TRC is subtracted from all other scenarios to estimate uncertainty. Results from the uncertainty analysis are provided in the main body of the report.

Affordability Impacts

Customer Affordability Model Overview

The Customer Affordability Model evaluates how the pathways scenarios impact customer energy bills and upfront appliance costs across different customer types (i.e., customers with appliances supplied by different fuels). The model explores how the rate impacts under each scenario affect customer decisions and the inflection points for when it is economic to convert to all-electric appliances or to invest in a deep building shell energy efficiency retrofit. The Customer Affordability Model considers the impacts on customers with various appliance mixes.

Table 18. Customer Types and Appliances Packages assumed in Affordability Model

Customer Type	Appliance Package
Gas Customer	Gas furnace, gas water heater, gas stove, gas dryer, etc.
Hybrid Gas Customer	Electric ASHP + gas furnace backup, water HP, electric stove, electric dryer, deep-shell retrofit, etc.
Efficient Gas Customer	Efficient gas furnace, efficient gas water heater, gas stove, gas dryer, deep-shell retrofit, etc.
All-Electric Customer	Electric ASHP, water HP, electric stove, electric dryer, deep-shell retrofit, etc.
Delivered Fuels Customer	Fuel oil furnace, fuel oil water heater, electric stove, electric dryer, etc.
Hybrid Delivered Fuels Customer	Electric ASHP + fuel oil furnace backup, water HP, electric stove, electric dryer, deep-shell retrofit, etc.
Networked Geothermal Customer	District geothermal HP, water HP, electric stove, electric dryer, deep-shell retrofit, etc.

Customer Affordability Model Design

Customer Energy Bills

To calculate the differences in customer energy bills, E3 calculates the energy consumption of each customer based on the sum of their appliances' energy use. E3 determines a baseline energy use for each appliance end use (e.g., space heating, cooking) based on the average energy use of a gas customer's appliances (e.g., gas furnace). The baseline energy use is calculated from the Residential Energy Consumption Survey (RECS) 2023 and the Commercial Building Energy Consumption Survey (CBECS) 2018 for single family homes, multi-family homes, and small and large commercial spaces for four building vintage periods. We then scale all other appliances' energy use from the baseline appliance energy use based on their relative efficiency of the appliance as compared to the gas appliance.

Air source heat pumps and ground-source heat pumps are assumed to increase in efficiency over time as there are improvements in newer heat pump technologies. A learning rate of 1.1% is applied to space heat pumps for every year after 2023, decreasing the space heating energy use for customers adopting heat pump appliances.

For customers retrofitting their buildings with deep-shell or light-shell energy efficiency upgrades, space heating and cooling energy use is assumed to decrease in line with the efficiency improvements. Efficiency parameters associated with these upgrades are provided in Appendix B.

E3 determines the energy bills for each customer type by summing the energy use of the customer's appliances supplied by each fuel (e.g., natural gas, fuel oil, electricity) and multiplying the energy by the fuel's rates under each Pathways scenario. For customers with any gas appliances, the gas bill also includes the monthly gas customer connection charge.

Customer Upfront Appliance Costs

The total upfront appliance cost is estimated for each customer's appliance package and is detailed in Appendix B. The estimate includes the cost of space heating, space cooling, water heating, cooking, clothes drying, and building shell retrofits. Appliance and building shell retrofit costs are scaled based on building size. The upfront appliance costs are then levelized using appliance lifetimes and RIE's WACC (7.15%) and then divided by 12 months to estimate monthly upfront costs.

Customer incentives, such as tax credits and rebates, reduce the upfront appliance costs paid by customers. The customer affordability model incorporates the Inflation Reduction Act (IRA) tax credits, Rhode Island state incentives, and RIE rebates for applicable appliances and building retrofits to provide a comparison of the affordability impact with and without these incentives.

A.5 Topics discussed with the TWG

An overview of topics as discussed with the Technical Working Group is provided in the table below.

Table 19. TWG Meeting Topics

Meeting Focus	Topics covered
Meeting #1: Introduction and Underlying PATHWAYS Assumptions	• Emissions Targets and Accounting • Key PATHWAYS Drivers (population, sectoral growth rates)
Meeting #2: Scenario Parameters & Reference Case	• Reference case policies and assumptions • Scenario-specific stock shares and parameters (incl. networked geothermal)
Meeting #3: Technology Performance & Sensitivity Parameters	• Scenario design parameters • Technology performance (i.e. heat pump efficiencies) • Sensitivity parameters: managed transition/gas decommissioning assumptions, efficiency sensitivities, pace of transportation electrification
Meeting #4: Renewable Natural Gas Part	• Biofuels module overview • Feedstocks availability to RI & competition with other sectors • RNG costing approach • Approach to modeling hydrogen and SNG • RNG emissions • Green hydrogen and synthetic NG production assumptions
Meeting #5: Net vs. Gross emissions	• Additional deep-dive meeting to discuss the net/gross emissions requirements associated with the Act on Climate
Meeting #6: Gas Sector Assumptions	• Historical gas system costs (rate base & revenue requirement) • Allocation of gas system costs to customer classes • LPP & gas system CAPEX forecasts • Gas system O&M forecasts • Detailed managed transition & networked geothermal assumptions (avoided costs, economics, feasibility)

Meeting #7: Electric Sector Assumptions and Resource Costs	• Approach to electric sector modeling in ISO-NE region (RESOLVE model) • Resource parameters & costs • Demand response assumptions • Peak impact modeling approach (RESHAPE model) T&D assumptions • Appliance costs
Meeting #8: Evaluation Metrics and Costs	• Metrics to measure affordability and equity outcomes • IRA and state customer incentive assumptions • Economy-wide costing assumptions and metrics • Discount rates • Other evaluation metrics
Meeting #9: Draft Report Outline and TWG feedback	• Deep-dive on TWG feedback (heat pump sizing and costs) • Technical Analysis Report