Michael J. Walsh, Ph.D.

Founding Partner, Groundwork Data

mjw@groundworkdata.org | www.groundworkdata.org

Integrated energy systems researcher with specific experience in economy-wide decarbonization planning, utility gas, building energy, and waste & bioenergy. Provides project design and oversight, research, report writing, testimony, speaking, and media engagements.

PROFESSIONAL EXPERIENCE

Founding Partner, Groundwork Data *2021-Present*
Launched an independent practice that evolved into a mission-driven consultancy committed to accelerating a clean, equitable, and resilient energy transition. Developing decarbonization strategy and analysis for non-profit, university, private sector, and government clients focusing predominantly on gas transition, electrification, and alternative fuels technology and policy.

Senior Associate, The Cadmus Group *2019-2020*
Technical decarbonization expert in a state and local policy practice group, responsible for coordinating projects, expert analysis, and quantitative work. Work spanned various sectors ranging from efficiency program analysis to natural carbon inventories.

Senior Research Scientist, Boston University Institute for Sustaianble Energy *2017-2019*
Lead researcher and project manager for an academic research institute. Primarily oversaw the development of a multi-report city decarbonization study.

EDUCATION & ACADEMIC APPOINTMENTS

- B.A. in Chemistry from *Colby College* (2005)
- Ph.D. in Environmental Engineering from *Cornell University* (2013).
- Research Fellow, *Bentley University Center for Integration of Science and Industry* (2013-2017)
- Research Assistant Professor, *Boston University Department of Earth and Environmental Sciences* (2018-2020)

REPORTS

Dorie Seavey, Michael Bloomberg, Conor Lyman, Michael J. Walsh., *Peoples Gas: Escalating business risk in a changing energy landscape.* (October 2024), Citizens Utility Board and Groundwork Data, http://www.groundworkdata.org/research/peoplesgas

Walsh, Michael J. *Pipeline Extension Allowances and the Future of Gas in Massachusetts.* Groundwork Data, (October 7, 2024). Groundwork Data for Conservation Law Foundation, Environmental Defense Fund, Sierra Club in MA DPU #20-80. https://www.groundworkdata.org/s/20-80GWDLineExtensionComment071024rev1.pdf

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Michael Walsh, Farrah Anderson, Jesse Way, Megan Lynch, Asa Hopkins, Pat Knight, Jason Frost. *Rhode Island Carbon Pricing Study*. (February 2021) Cadmus Group for Rhode Island Department of Environmental Management, Office of Energy Resources & Department of Transportation. https://energy.ri.gov/sites/g/files/xkgbur741/files/documents/carbonstudy/final-rhode-island-carbon-price-study-report.pdf

Massachusetts 2050 Decarbonization Roadmap

Massachusetts 2050 Decarbonization Roadmap. (December 2020) Cadmus Group for Massachusetts Executive Office of Energy and Environmental Affairs. https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download

Building Sector Technical Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study. (December 2020) Cadmus Group for Massachusetts Executive Office of Energy and Environmental Affairs. https://www.mass.gov/doc/buildings-sector-technical-report/download

Transportation Sector Technical Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study. (December 2020) Cadmus Group for Massachusetts Executive Office of Energy and Environmental Affairs https://www.mass.gov/doc/transportation-sector-technical-report/download

Economic and Health Impacts Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Stud (December 2020) Cadmus Group for Massachusetts Executive Office of Energy and Environmental https://www.mass.gov/doc/economics-and-health-impacts-report/download

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Atyia Martin, D'Janapha Fortune, Sam LaTronica (All Aces); Elizabeth A. Stanton, Bryndis Woods, Eliandro Tavares, Tanya Stasio, Ricardo Lopez, Sagal Alisalad, Myisha Majumder, Namgay Tshering (Applied Economics Clinic); Cutler J. Cleveland, Peter Fox-Penner, Michael J. Walsh, Margaret Cherne-Hendrick, Sucharita Gopal, Joshua R. Castigliego, Taylor Perez, Adam Pollack, Kevin Zheng, Emma Galante (Institute for Sustainable Energy, now IGS) *Carbon Free Boston Social Equity Report.* (May 2019) Boston University Insitute for Sustainable Energy for Boston Green Ribbon Commission. https://www.bu.edu/igs/2019/05/21/carbon-free-boston-social-equity-report/

PEER-REVIEWED MANUSCRIPTS

A list of academic publications is available on my **Google Scholar Page**

SELECTED PRIVATE SECTOR WORK

Waste Emissions Impacts Analysis for Boston University. Completed a waste greenhouse gas emissions inventory and impact assessment using various university waste data streams. (2021)

Rose Kennedy Greenway Conservancy Emissions and Carbon Stock Analysis. Oversaw Boston-based public park's climate mitigation planning. Oversaw emissions accounting and developed a tool for calculating the carbon stored in the park's natural assets. (2020)

Waste-to-X Sustainability Indicators, *Technical and Stakeholder Engagement Specialist* with Pacific Northwest National Laboratories for DOE Bioenergy Technologies Office. Developing a pathways analysis framework for evaluating the tradeoffs of alternative waste energy recovery strategies for cities and regions.

AWARDS

- Bishop Brady High School *Distinguished Alumni Award* (2024)
- Boston Business Journal 40 under 40 (2022)
- Bentley University *Innovation in Teaching Award* (2016)
- New England Aquarium *Young Professionals Advisory Committee* (2014)
- American Institute of Biological Sciences *Emerging Public Policy Leadership Commendation* – (2011)
- Student Elected Trustee – Cornell University (2008-2010)
- President's Climate Commitment Implementation Committee – Cornell University (2007-2009)

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

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

April 2024

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.

Study authors: Niki Lintmeijer, Tory Clark, Stephanie Kinser, Molly Bertolacini, Kenzie Schwartz, Bill Wheatle, Charles Li, Dan Aas, Sean Smillie

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A.1 Economywide Pathways and Emissions

The E3 PATHWAYS Model

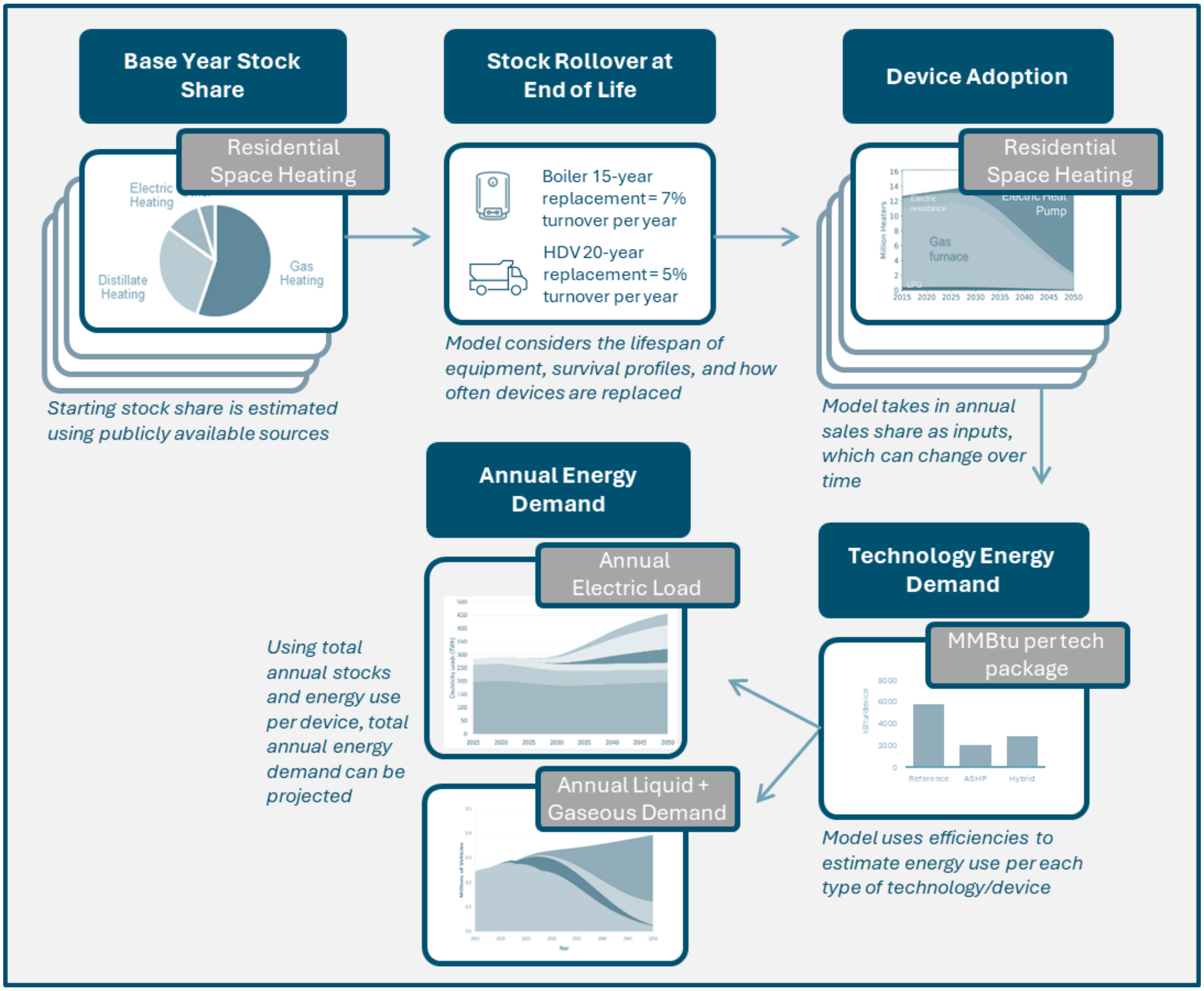
The E3 PATHWAYS model identifies the interactions between GHG measures across different sectors of the economy, such as transportation, buildings, and industry. Utilizing an economywide representation of technology, infrastructure, energy use, and emissions, the model enables an evaluation of long-term 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

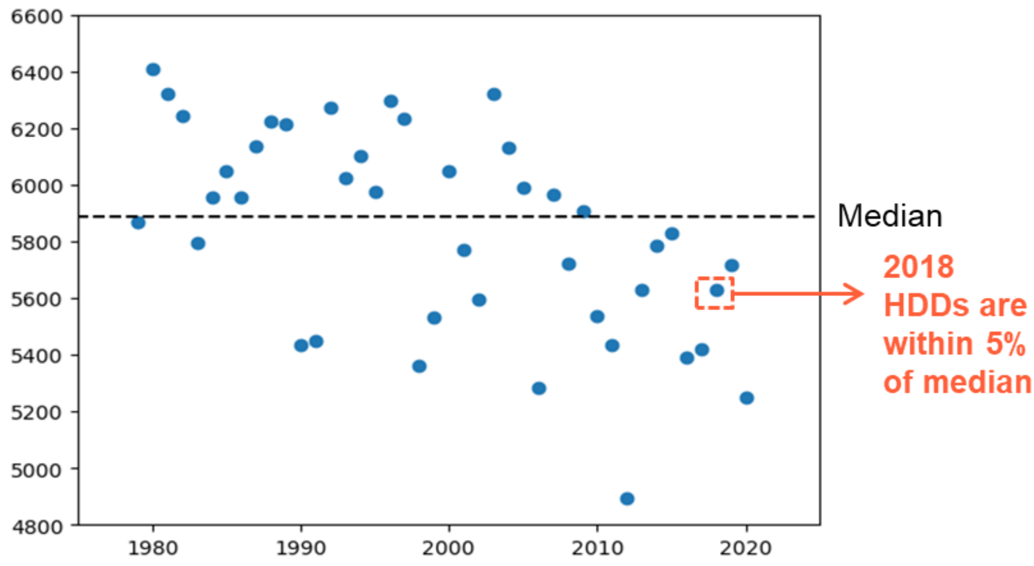
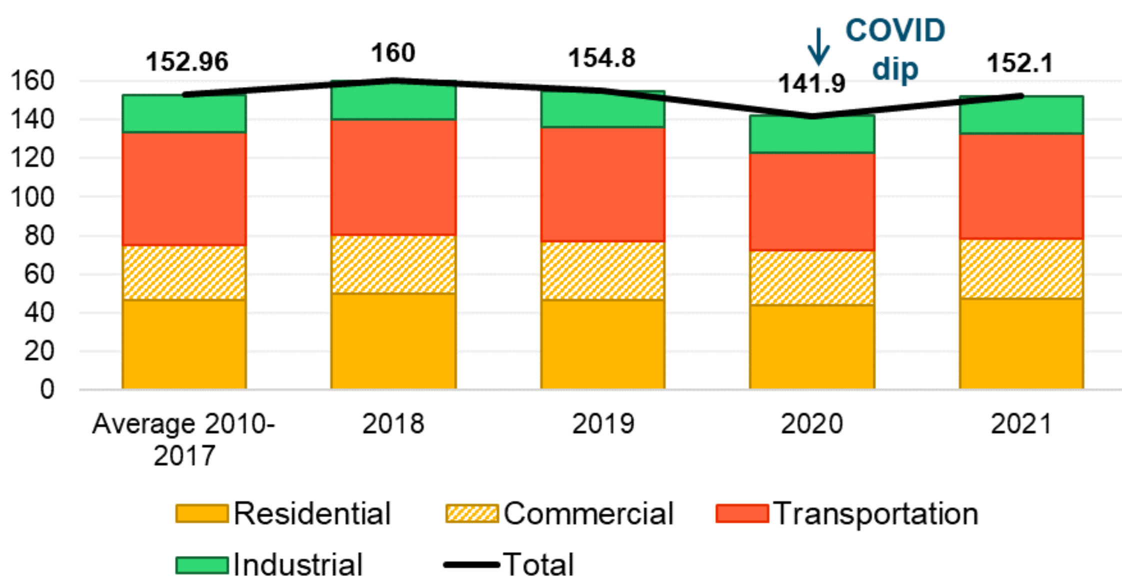


Figure 3. Economywide Energy Demand in Rhode Island (Tbtu)



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.

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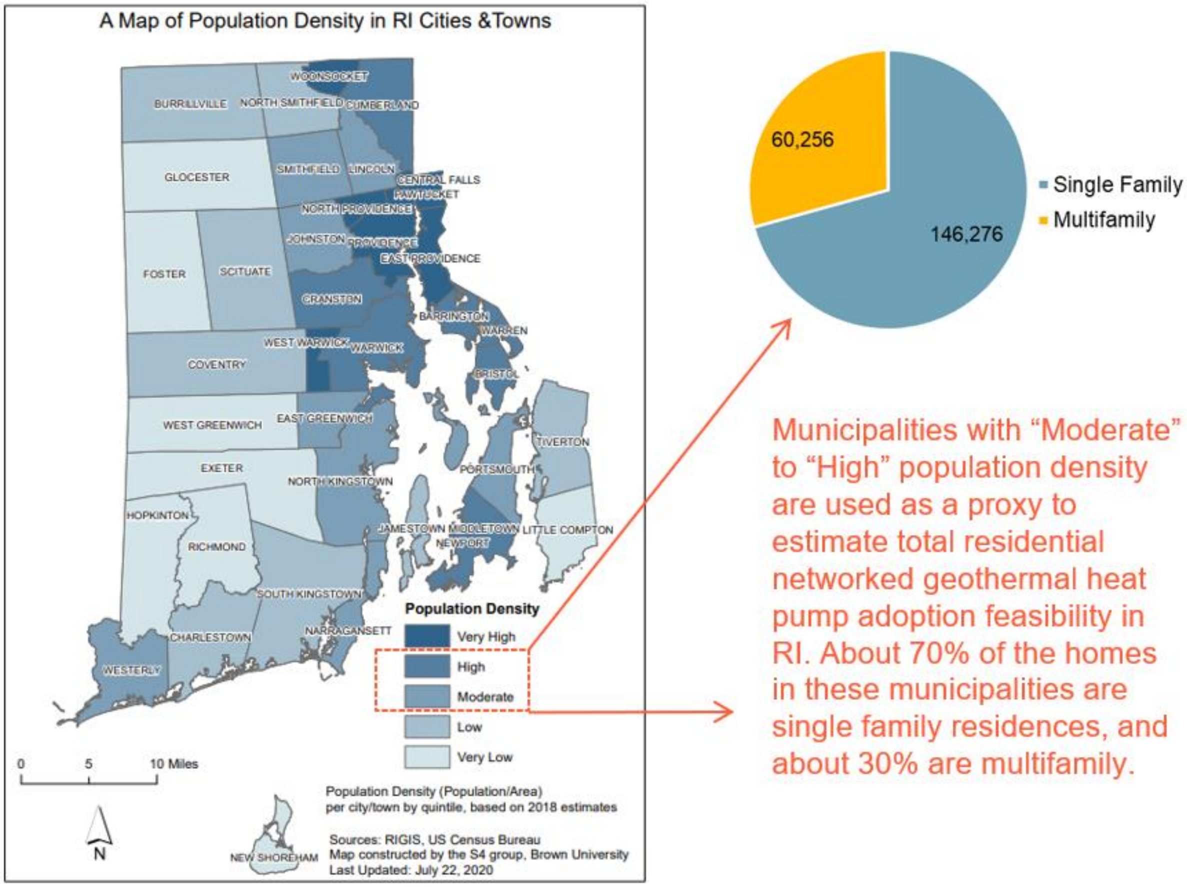
[8] HEET, Buro Happold Engineering. 2019. Geothermal Networks 2019 Feasibility Study. https://assets-global.website-files.com/649aeb5aaa8188e00cea66bb/656f8ad67bbc7df081e3fe17_Buro-Happold-Geothermal-Network-Feasibility-Study.pdf.

[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]

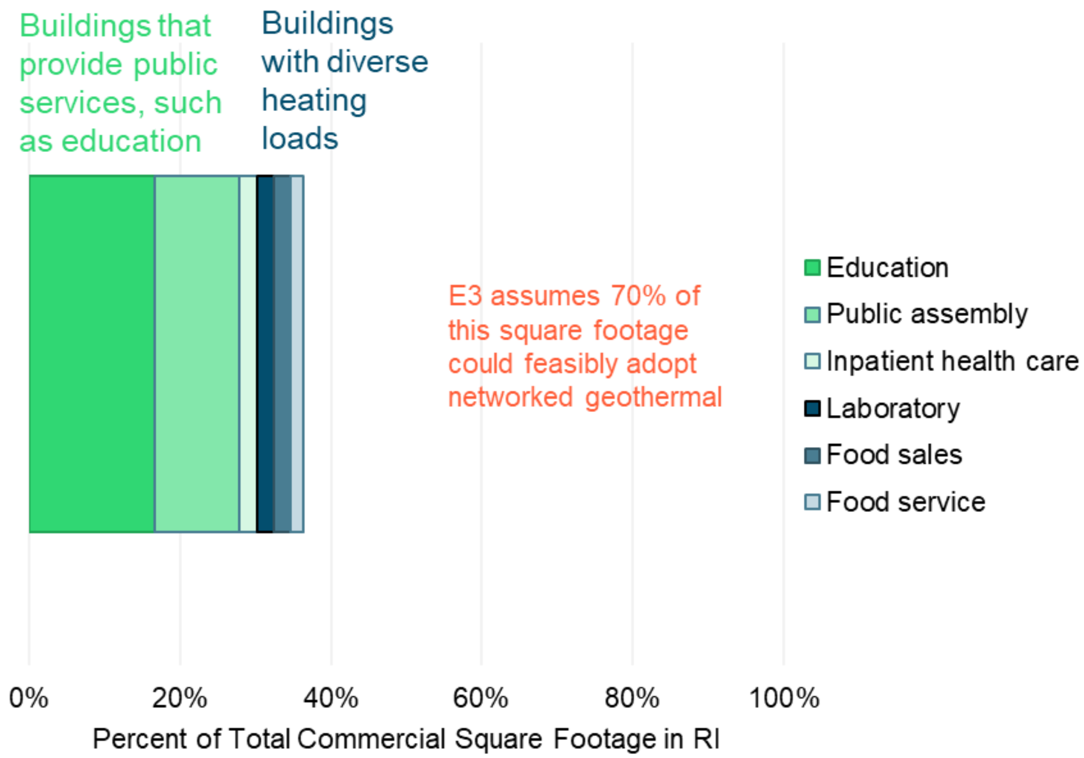


The commercial sector offers several opportunities for networked geothermal adoption. As of 2023, many district heating and cooling systems in the U.S. are on college campuses. In the Alternative Heat Infrastructure scenario, E3 assumed that about 70% of the following building types could reasonably 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

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

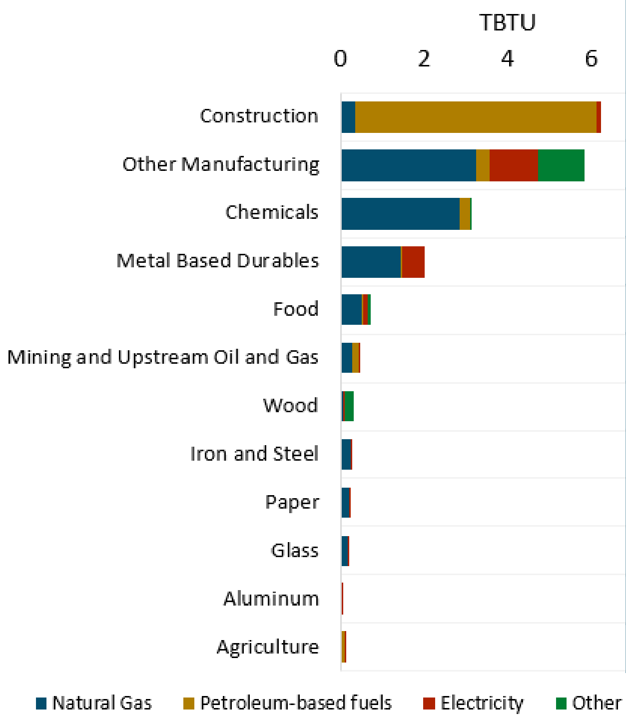
E3 used the Energy Information Administration (EIA) State Energy Data System (SEDS) and the Manufacturing Energy Consumption Survey (MECS) to determine the existing type and quantity of energy used by industrial subsector. Appendix B includes detailed assumptions for baseline energy demand by subsector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

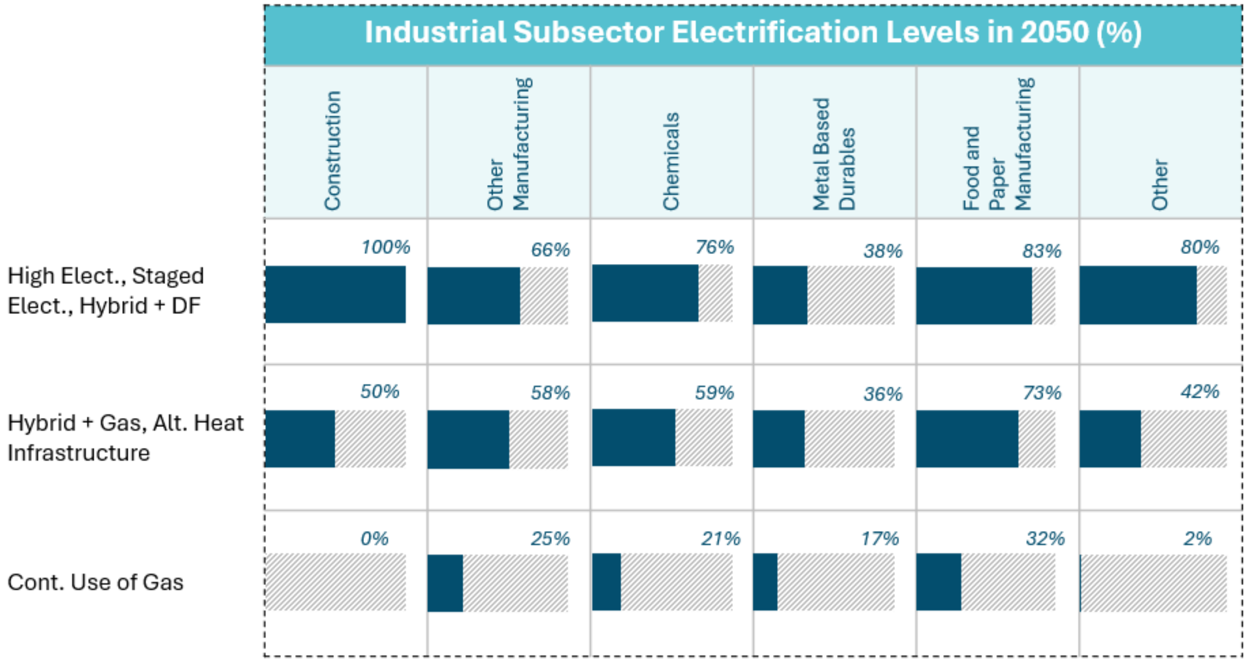


	% of energy use for high-temperature process heat	% of energy use for boiler use, cogen, HVAC and other	% of energy use unknown/not reported
Construction	0%	0%	100%
Other Manufacturing	35%	50%	15%
Chemicals	24%	42%	34%
Metal Based Durables	62%	34%	4%
Food	20%	54%	26%
Mining and Upstream Oil and Gas	0%	0%	100%
Wood	0%	0%	100%
Iron and Steel	37%	10%	53%
Paper	8%	91%	1%
Glass	74%	5%	21%
Aluminum	78%	19%	3%
Agriculture	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.

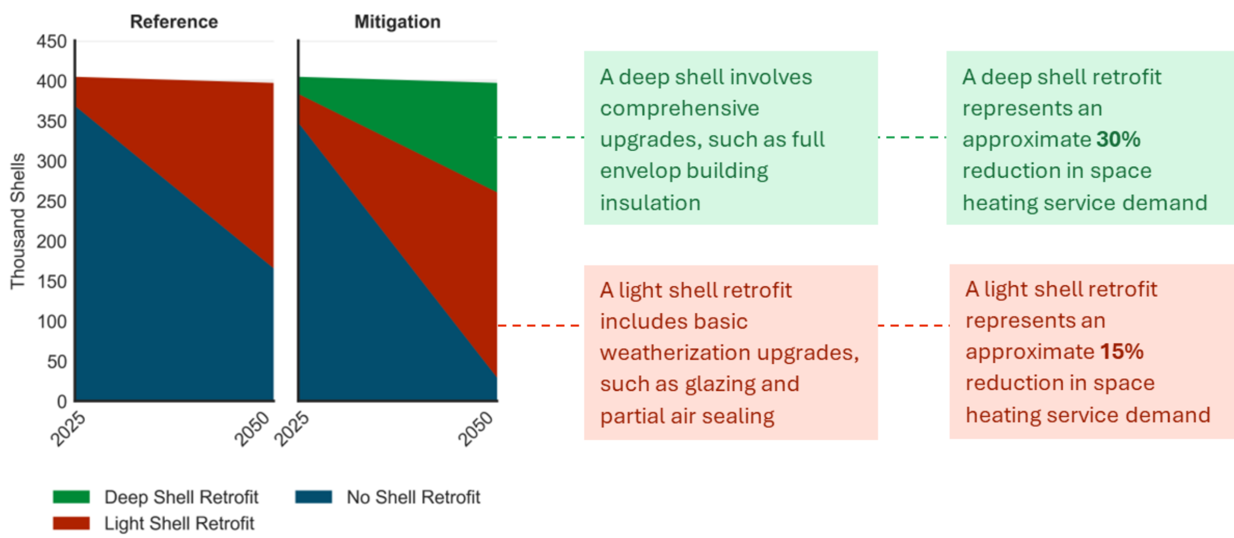
Weatherization and Building Shells

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

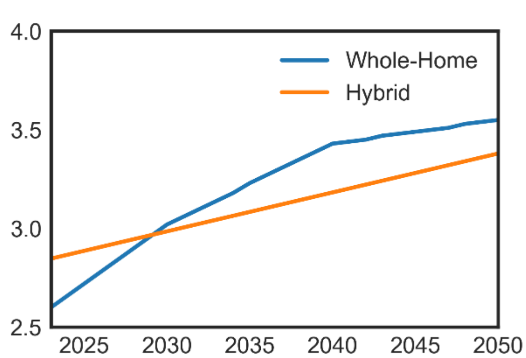


Heat Pump Efficiency

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.

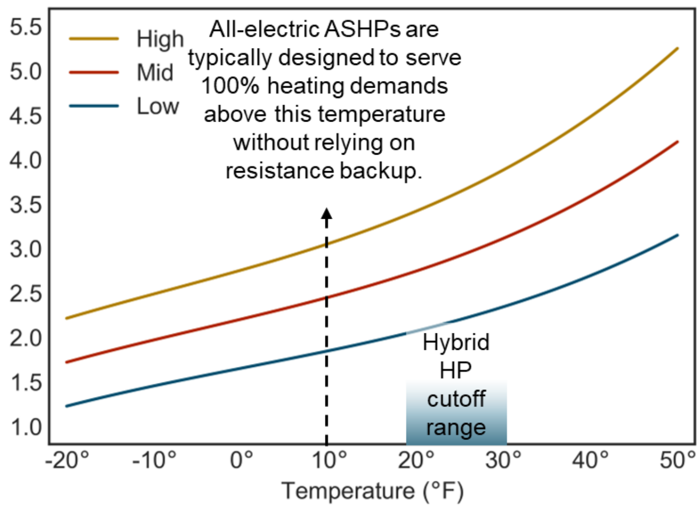
A variety of space heating technologies were modeled in this work, including standard and efficient combustion devices, several types of air-source heat pumps (ASHPs), networked geothermal, and ground source heat pumps. In general, all device efficiencies were assumed to either improve or remain static 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

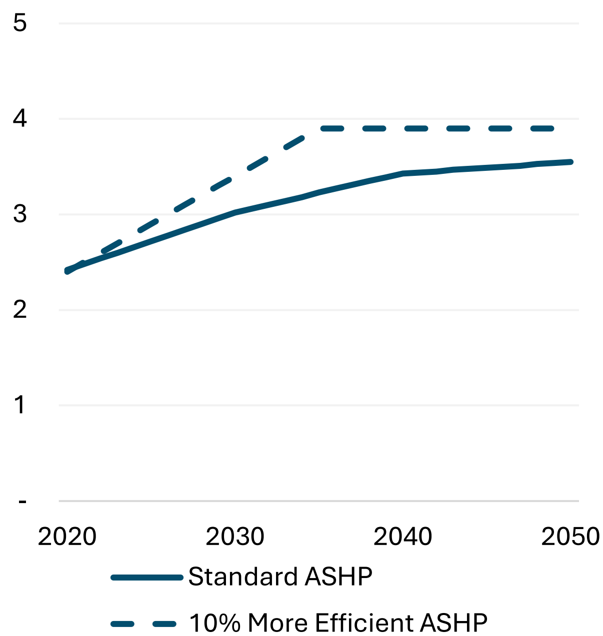
Due to the inherent uncertainty in all assumptions-based PATHWAYS modeling, E3 explored three primary types of sensitivities that vary the level and pace of emissions reductions under different conditions:

+ **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

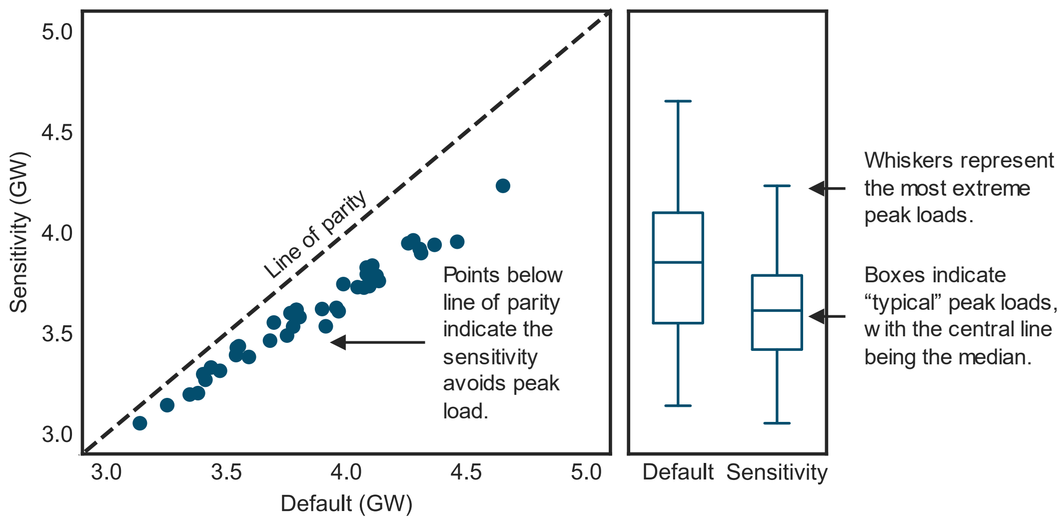
To explore the electric sector impacts resulting from the adoption of higher efficiency all-electric technology, E3 modeled an approximate 10% increase in Coefficient of Performance (COPs) for ASHPs and hybrid ASHPs by 2050 in the High Electrification scenario only, as shown in Figure 11. These higher-efficiency 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



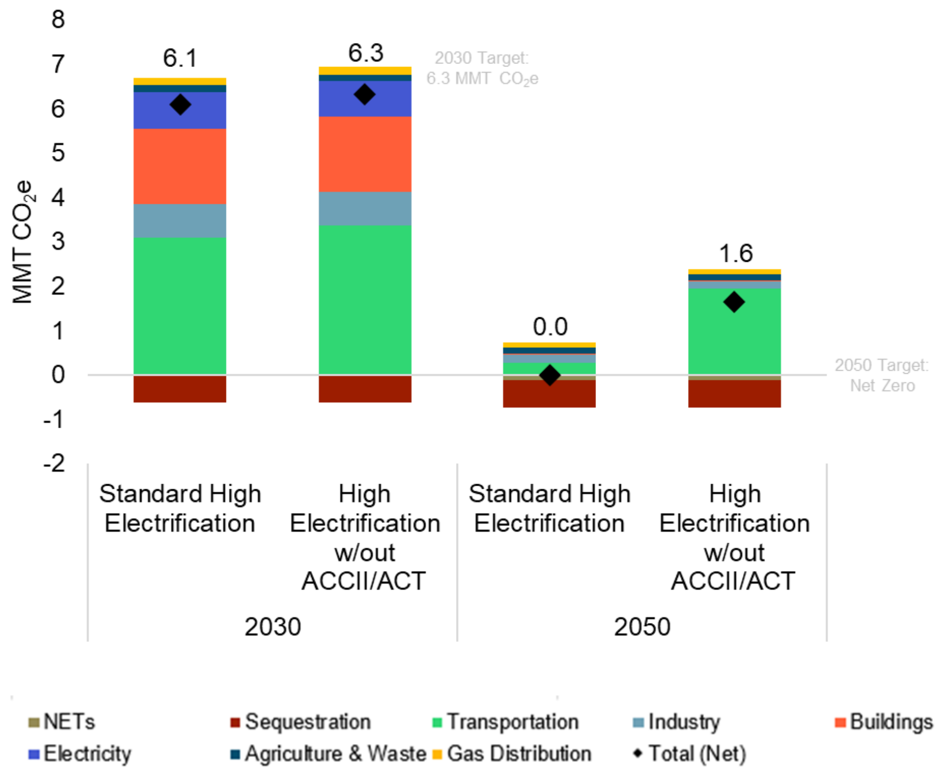
Lower Levels of Transportation Electrification

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

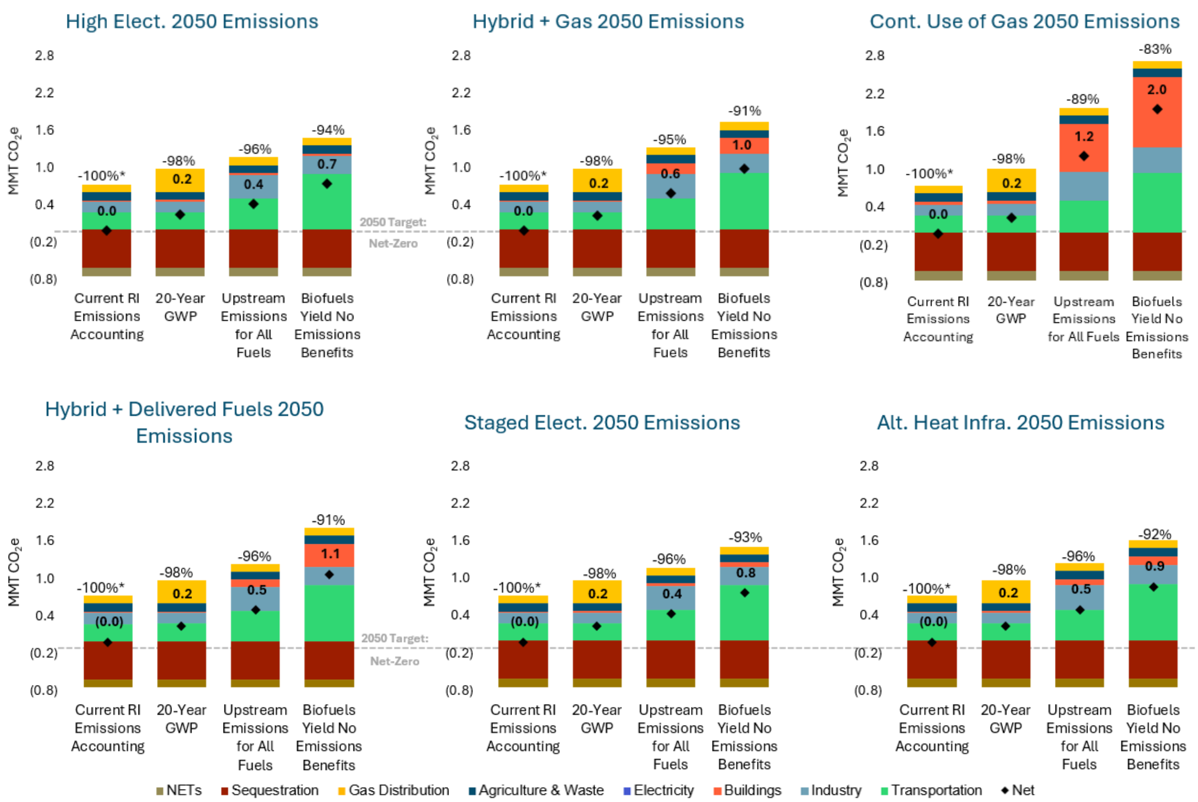
[26] Sources for RNG emissions factors: ICCT 2030 CA RNG Outlook; Comparative Life Cycle Evaluation of the GWP Impacts of RNG; At Scale, RNG Systems Could be Climate Intensive

[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

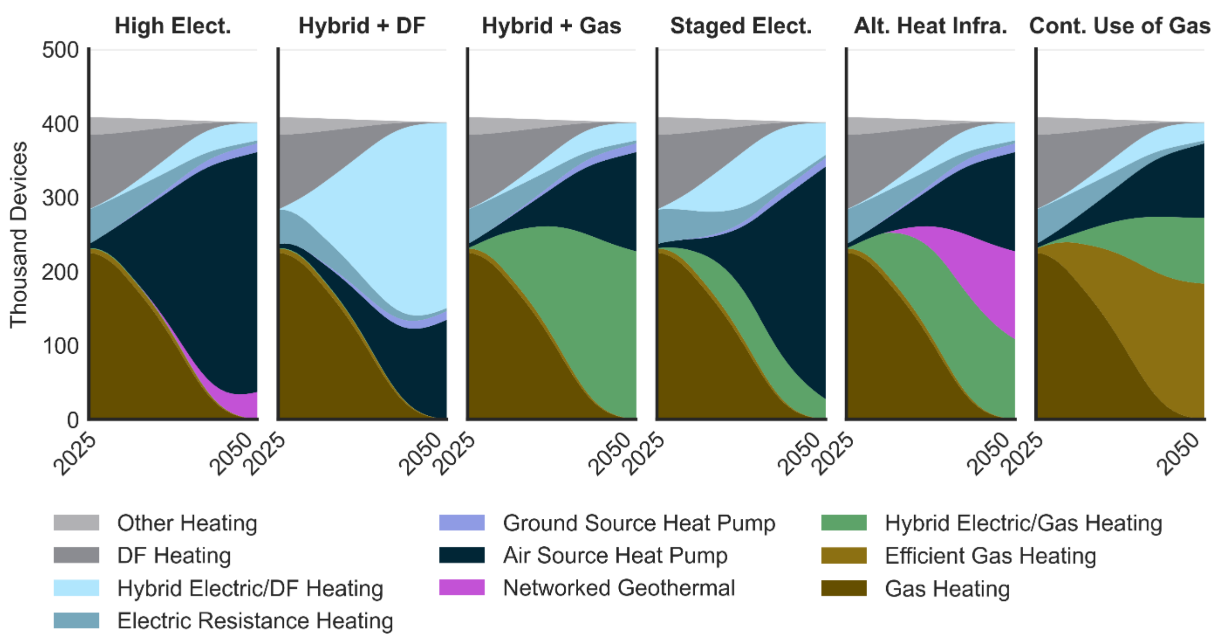
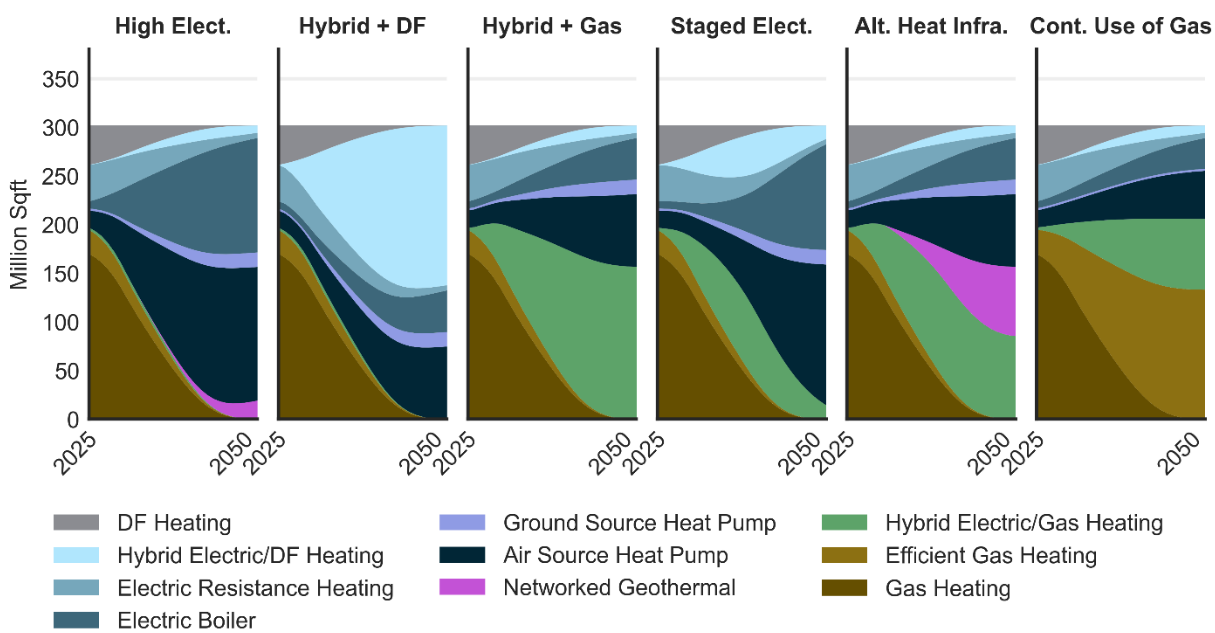


Table 5. Residential Space Heating Stock Breakdown Results in 2050

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

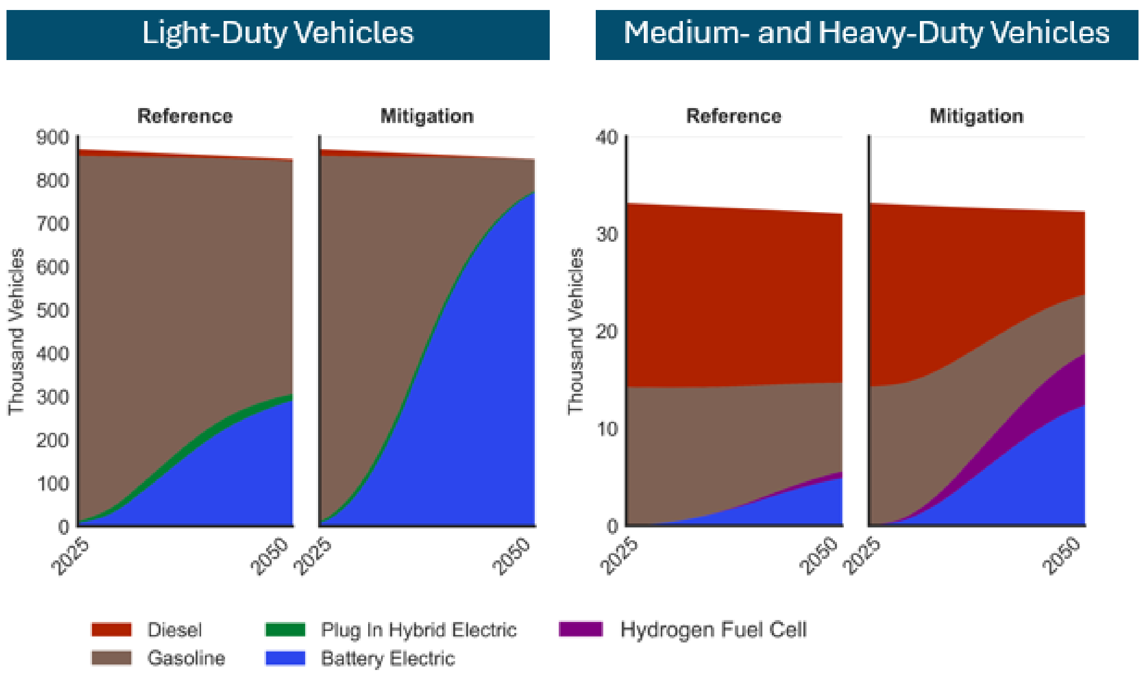
Across all scenarios, cooking and clothes drying subsectors electrify at the same pace as space heating electrification. In this case, hybrid space heating adoption counts as electrification. Therefore, all decarbonization scenarios except for Continued Use of Gas fully electrify cooking and clothes 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

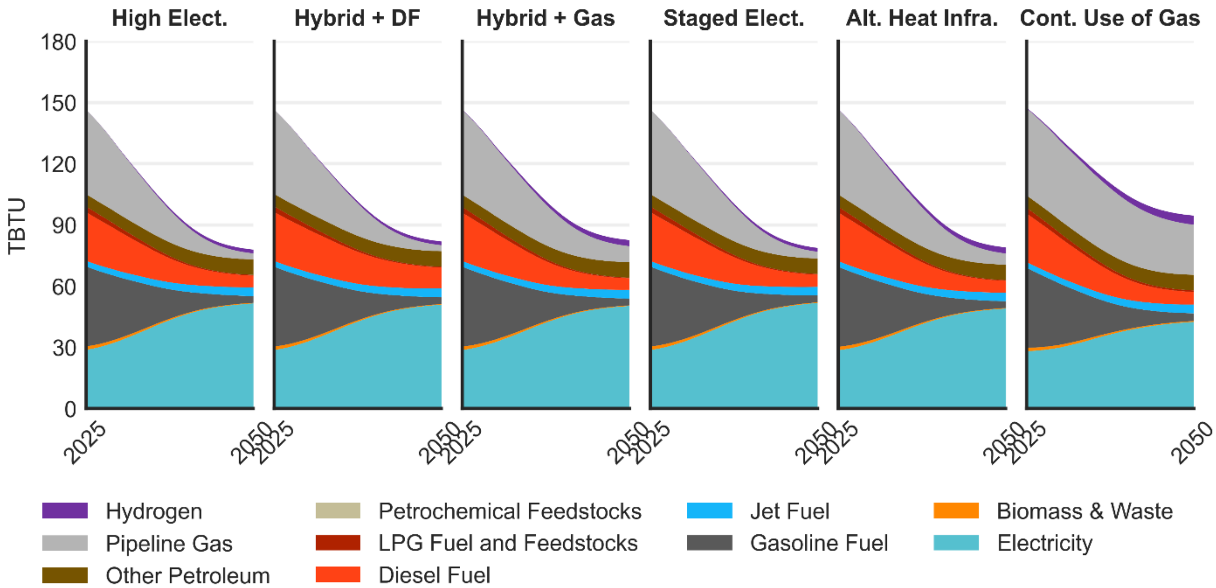
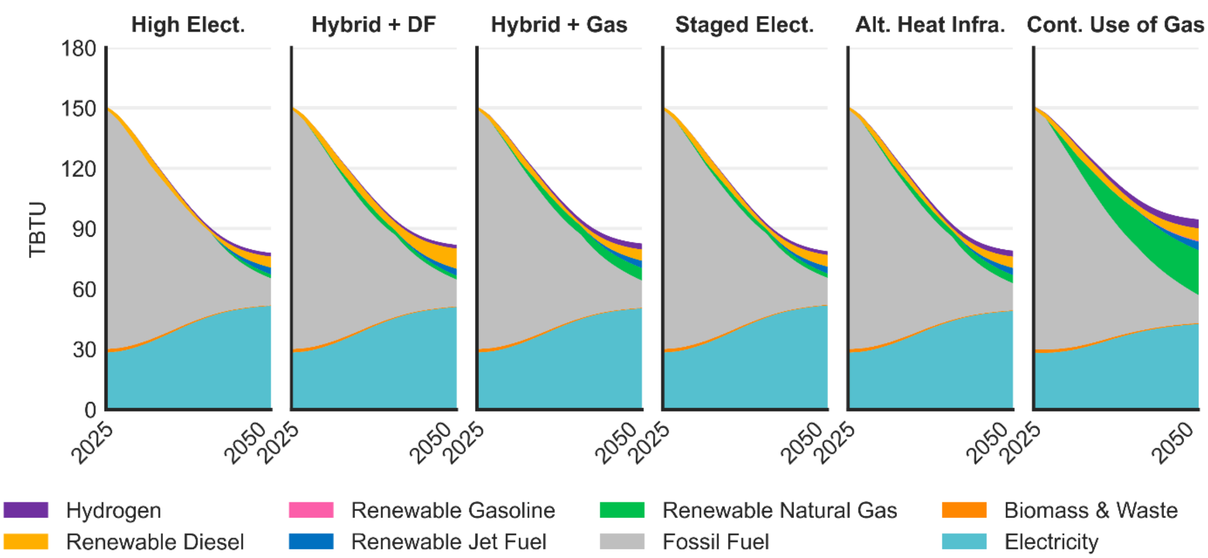


Figure 19. Economywide Energy Demand Across Scenarios (Including Renewable Fuels)

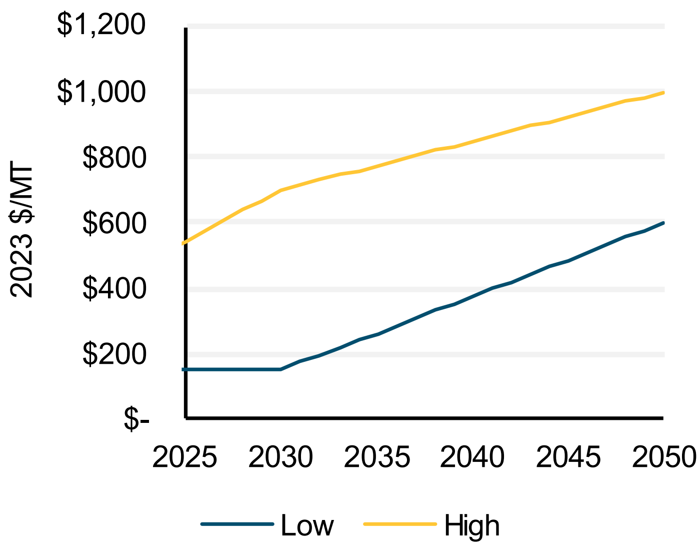


Fuels

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:

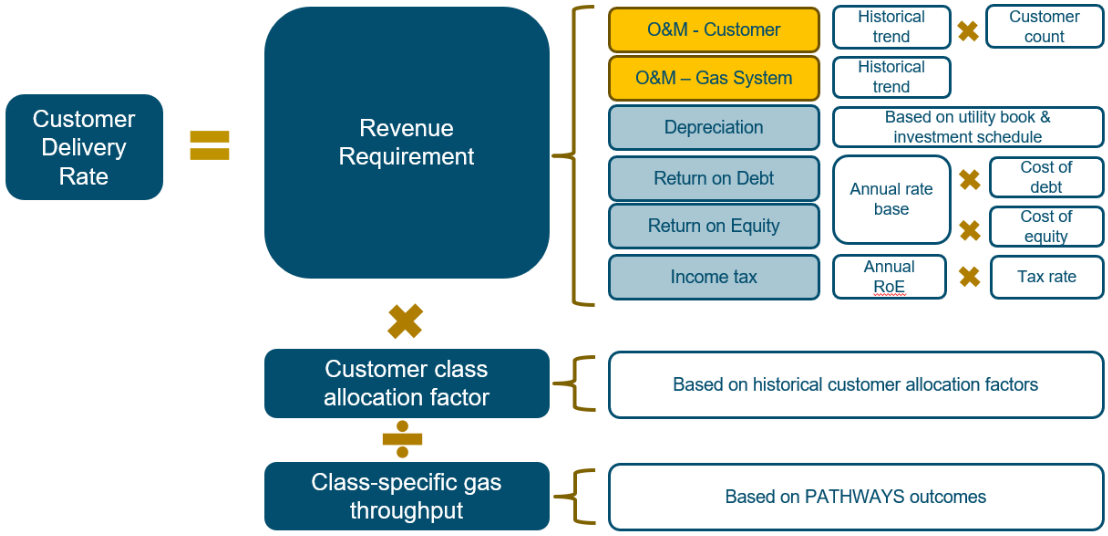
- A forecast of revenue requirement over time, broken out by depreciation, return on capital, income taxes, and O&M expenses.
- Rates by customer class, broken out by gas delivery rate (recovery of the revenue requirement) and gas supply costs (recovery of gas commodity costs and transportation costs).

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

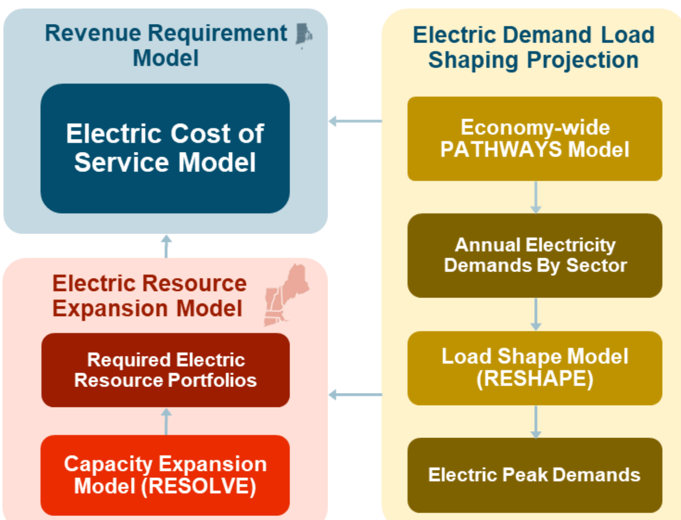
[36] IEA Energy Technology Systems Analysis Program. January 2013. District Heating Technology Brief. https://iea-etsap.org/E-TechDS/PDF/E16_DistrHeat_EA_Final_Jan2013_GSOK.pdf

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.

[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.

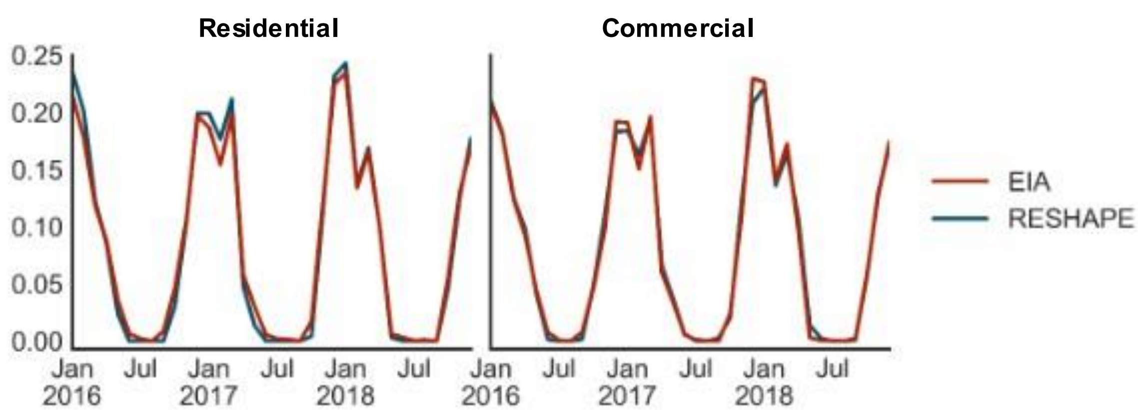
Table 15. Load Flexibility Assumptions

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.

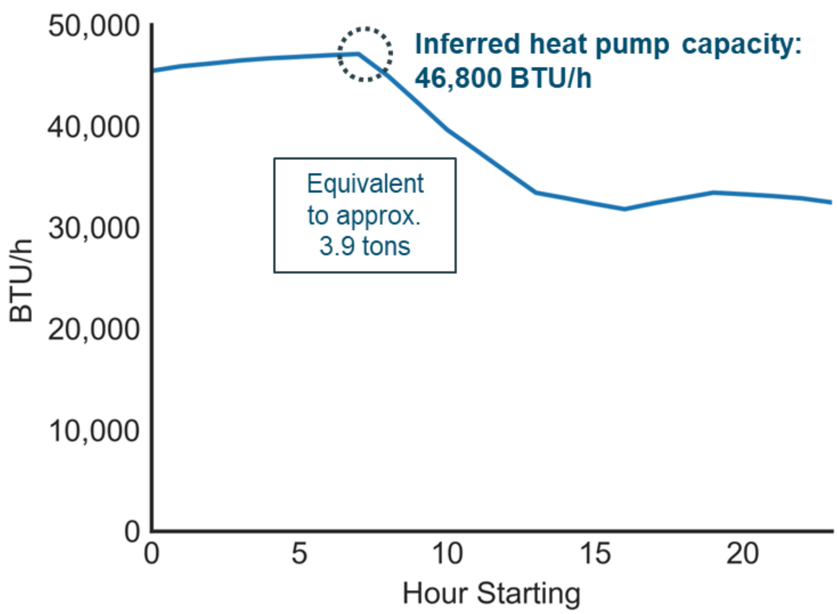


RESHAPE's sensible space heating demands were benchmarked to replicate the seasonality of monthly residential and commercial gas sales as reported by the US Energy Information Administration (EIA) in Rhode Island from 2016-2018. By using this benchmarking approach, E3 assumed that seasonal gas sales 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

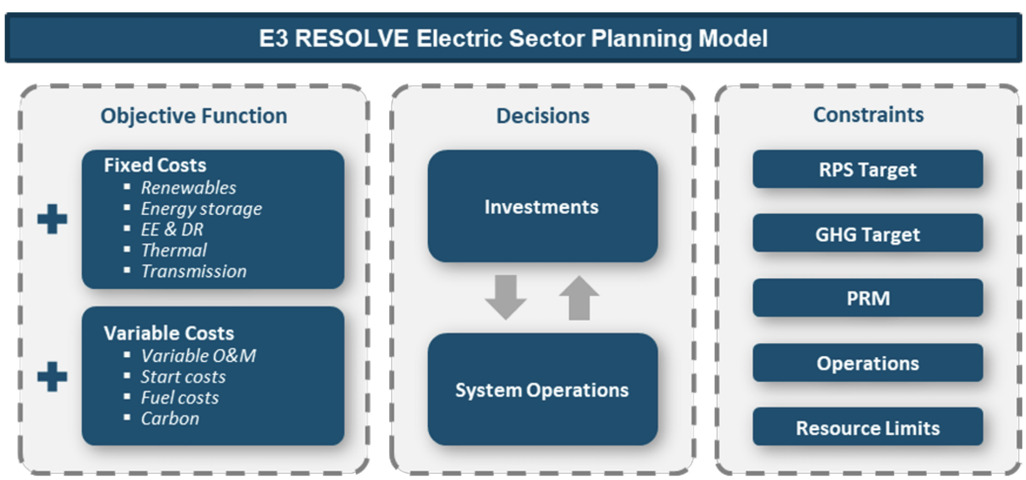
E3 applied the New England RESOLVE capacity expansion model in this study to model generation resource requirements and cost across the ISO-New England (ISO-NE) area. ISO-NE was modeled in its entirety because of the connectedness and interdependence of Rhode Island in the regional ISO-NE electricity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

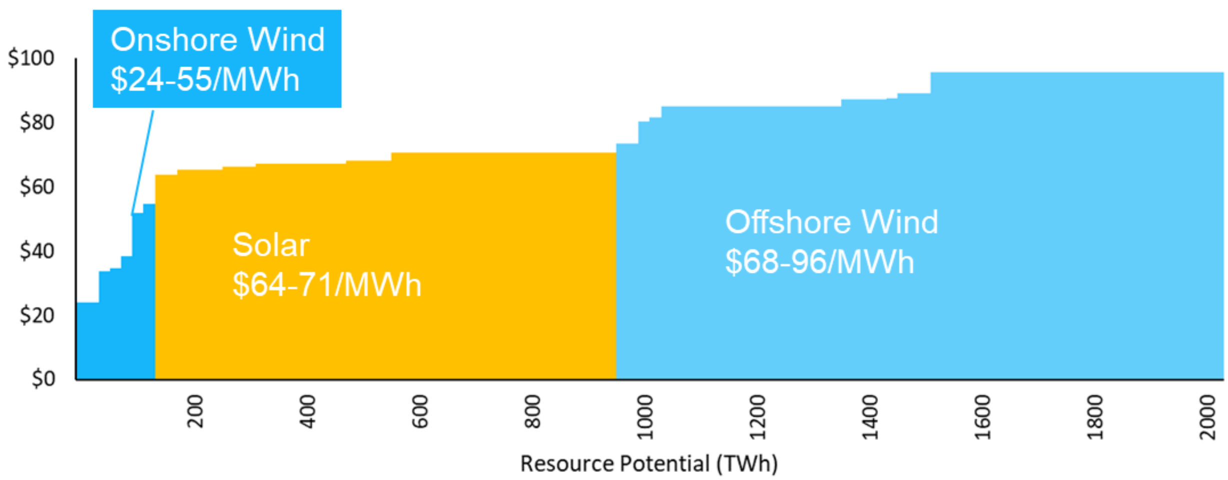
Figure 25. Overview of E3's RESOLVE Model



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

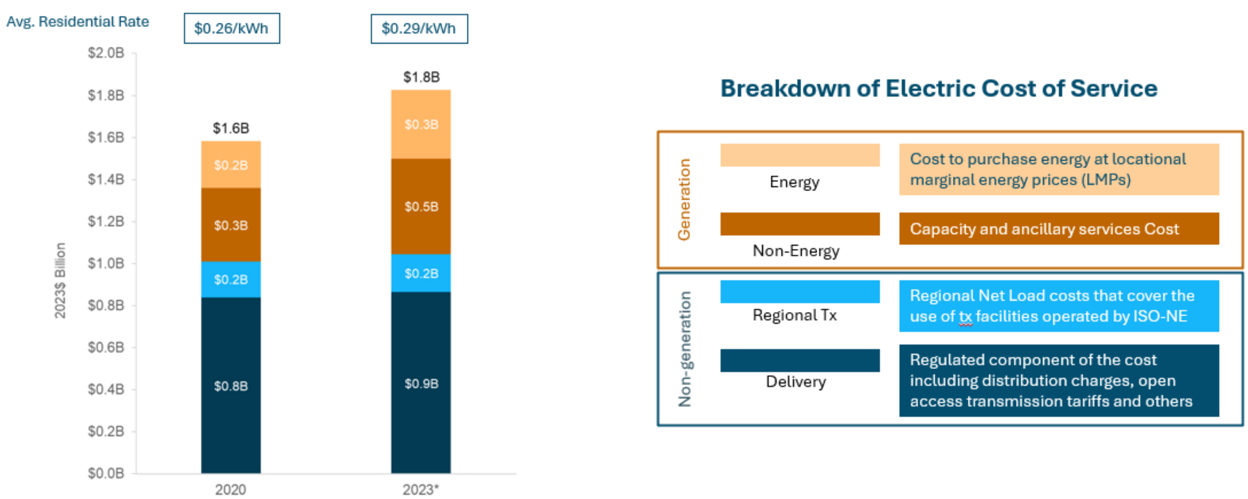


In addition to renewables, other clean resources were modeled for their critical roles to help achieve deep GHG reductions in the electric sector. Li-ion battery storage with 4-hour duration was modeled and its costs benchmarked to recent market trends showing upfront cost of approximately $1,500/kW. 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	Direction	Drivers of Non-generation Cost Changes	Direction
• **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.

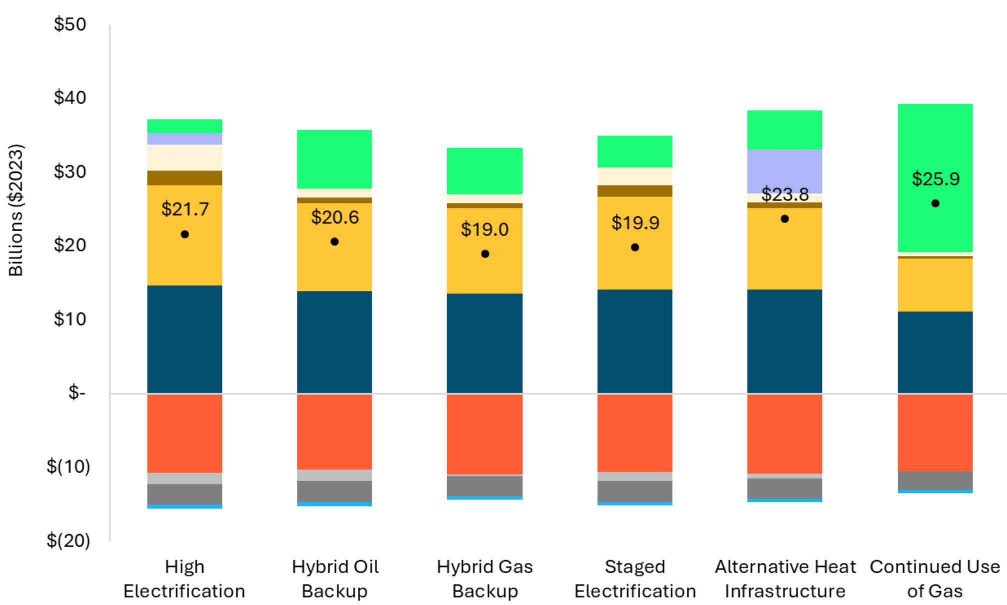
The model calculates both an annual and cumulative net present value (NPV) incremental TRC. To do so, the model utilizes a combination of sector-specific financing rates and a single societal discount rate that is applied economywide. Sector-specific financing rates are used to calculate annual costs 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.

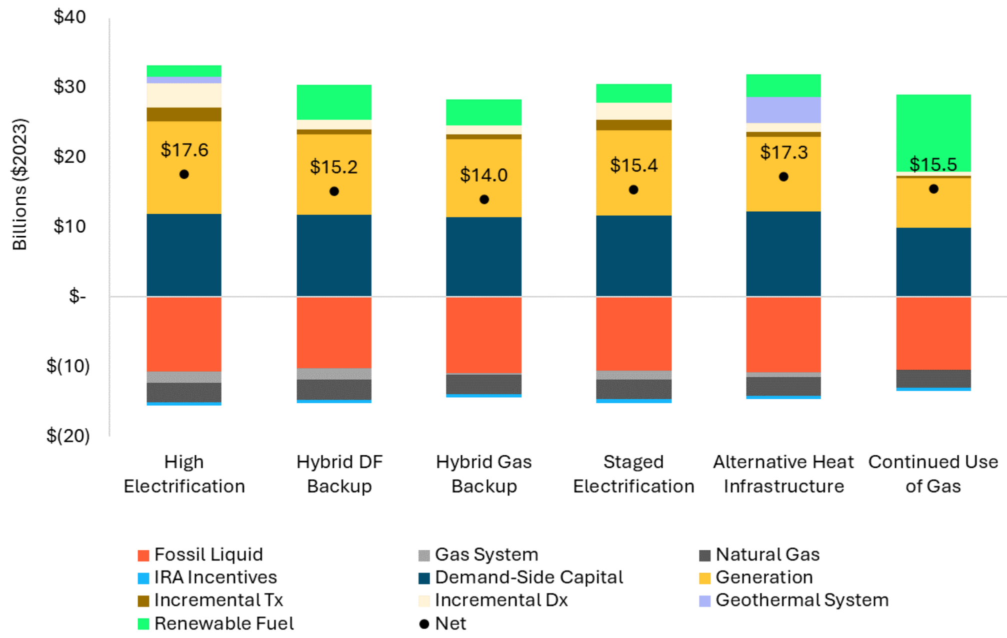
The Economywide Cost Model estimates incremental TRCs across a set of sensitivities including "low" and "high" cost assumptions as well as the cost impact of a managed gas transition. Low and high cost trajectories are included in the model for the majority of cost components and mirror the sensitivities 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

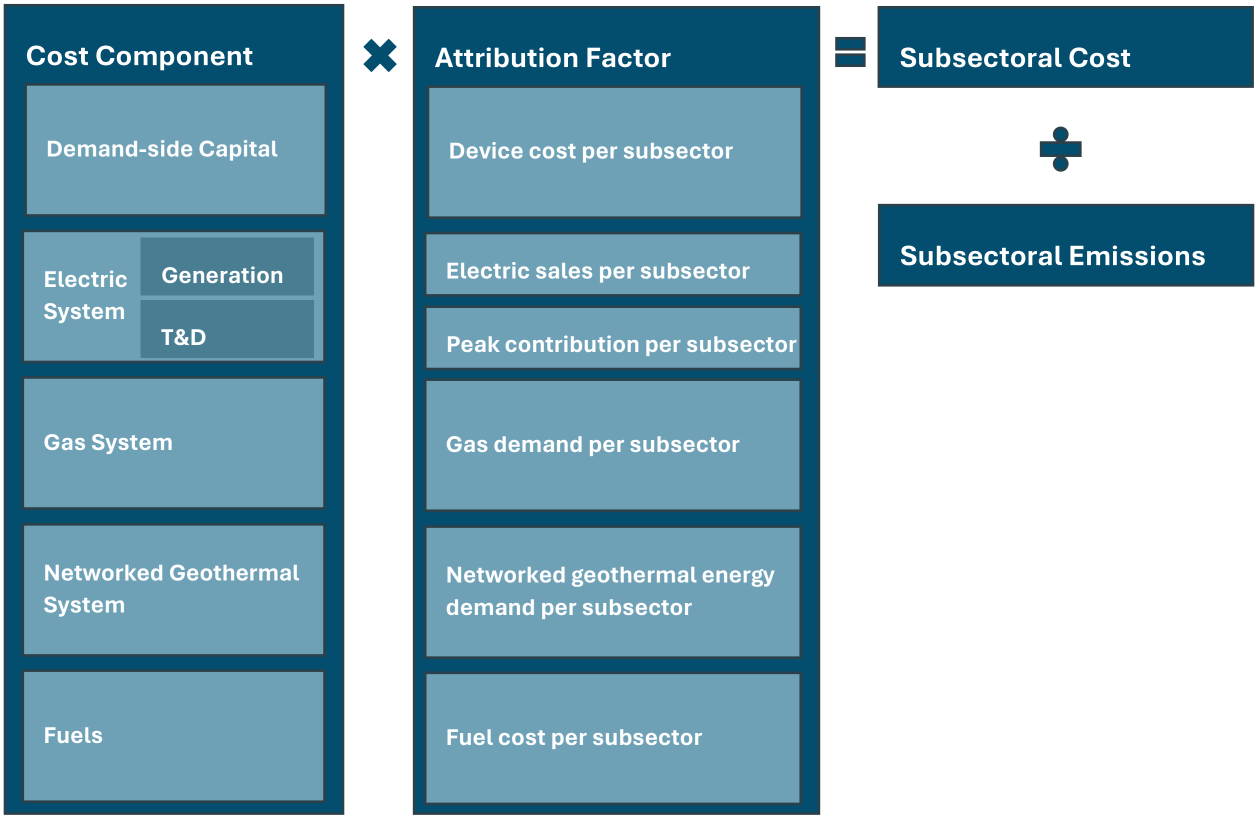




Subsectoral Abatement Cost Analysis

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 Abatement 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

CLF 1-3

NPA Framework

January 15, 2025

BERKSHIRE GAS An AVANGRID Company
EVERSOURCE
Liberty
nationalgrid
Unitil

Agenda

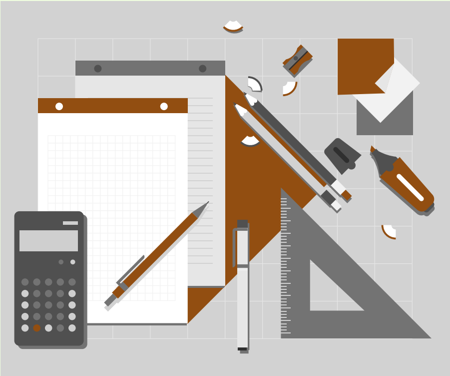
1. NPA Identification Process
2. Customer Education, Engagement and Commitment
3. Impacts to Project Implementation
4. Framework Updating

CLF 1-3

NPA Identification Process

NPA Identification Process

- Project Identification
- Initial Viability Testing
- System Feasibility Review
- Electric System Review
- Benefit Cost Analysis
- Project Authorization
- Project Prioritization
- Project Execution



- Defines the Step-by-Step process which the Companies will use to identify likely NPA Candidates
- Each step in the NPA Identification Process is accompanied with requirements the Companies must fulfill when reviewing their projects
- Ensures optimal use of resources by avoiding time and resource expenditures for projects that are not high likelihood candidates

Project Identification (1/4)

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CLF 1-3

Project Identification

Initial Viability Testing

System Feasibility Review

Electric System Review

Benefit Cost Analysis

Project Authorization

Project Prioritization

Project Execution

The Companies shall initiate the NPA Identification Process as defined in this NPA Framework for all projects identified as requiring such review.

- Understanding which capital investments by the LDCs are suitable for NPA review and which are not is an essential first step in ensuring an efficient NPA Process.
- Not all program types are conducive to an NPA review.

Reference: Table 1a) Types of Capital Projects

Program	High Level Descriptions (may vary by LDC)	Part of NPA review
GSEP	Replacement of leak-prone infrastructure	**Yes**
Reliability - Capacity	Projects to increase the capacity of the system such as system reinforcements, new gate stations and new regulator stations	**Yes**
Reliability - Replacement	Replacement projects such as Low-Pressure Conversion and Flood Hardening Projects, MAOP Compliance	**Yes**
Gate Stations & Regulator Stations	Replacement of equipment in poor condition to improve system reliability	**Yes**
LNG/LPGA	Provide critical gas supply that supports the system	**Yes**
Resiliency	Projects that increase the overall ability of the natural gas system's ability to withstand and recover from significant disruptions such as natural disasters and extreme weather events	**Yes**
New Customer Request	New Customer services and main extensions	**Yes**
DOT/Municipal Relocations	Address gas main conflicts related to the state DOT or Municipal reconstruction	**Yes**
Master Meter Compliance	Replacement of customer owned piping beyond the meter set to bring it up to compliance	**Yes**
Emergent	Unplanned work that addresses immediate safety concerns	**No**
Other Reliability	Projects that support the gas system (Stub Cut-offs, Corrosion Control, Tools and Equipment, etc.)	**No**
Metering	Work on Residential and C&I meters (i.e., meter exchanges), improvements to complex meter installations	**No**
Facilities	Work to facilities such as fencing, building maintenance, painting, security.	**No**
Information Technology	Investments in IT equipment and systems such as those used for pressure regulation, gas dispatch, customer billing cybersecurity, etc.	**No**

Project Identification (2/4)

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CLF 1-3

Project Identification

Initial Viability Testing

System Feasibility Review

Electric System Review

Benefit Cost Analysis

Project Authorization

Project Prioritization

Project Execution

The Companies shall initiate the NPA Identification Process as defined in this NPA Framework for all projects identified as requiring such review.

- Understanding which capital investments by the LDCs are suitable for NPA review and which are not is an essential first step in ensuring an efficient NPA Process.
- Not all program types are conducive to an NPA review.

Reference: Table 1b) Excluded Programs

Program	Reason for Exclusion	Part of NPA review
Emergent	Immediate action is required to maintain safe operation of the system. These projects require immediate action to maintain the safety and reliability of the gas system and therefore do not afford the time to conduct the NPA Identification Process.	**No**
Other Reliability	The work that is classified under this program may vary by company. In general, this is a bucket of work that does not fit into traditional programs but still maintains safety and reliability of the gas system. Projects like stub cut offs (which shorten stubs in the street) or corrosion control (which repairs and enhances the systems protecting steel pipelines) are vital to the system safety and not possible to replace with an NPA.	**No**
Metering	Metering involves meter purchases and replacements on the gas system for both residential and C&I customers. Most of the work in this program is to comply with statutory obligations to replace gas meters every 7 years. This program is not suitable for NPA review as the work is required compliance, date driven by individual location, identified at a program level rather than at a project level and is low cost compared to other programs.	**No**
Facilities	The work to repair aging facilities, enhance security and general maintenance of facilities (such as painting or roof repairs) is minor work that is not directly related to pipeline infrastructure and is not suitable for NPA review.	**No**
Information Technology	This work involves software purchases, updates, work on telemetry and helps the overall safety and functionality of the system. This program is used to make purchases and upgrades that keep the system operating, allowing the Company identify issues and maintain a reliability service.	**No**

Total project volume in excluded programs represents a very small percentage of work and dollars (varying by LDC and year) of the annual capital plan

Project Identification (3/4)

Project Identification

Initial Viability Testing

System Feasibility Review

Electric System Review

Benefit Cost Analysis

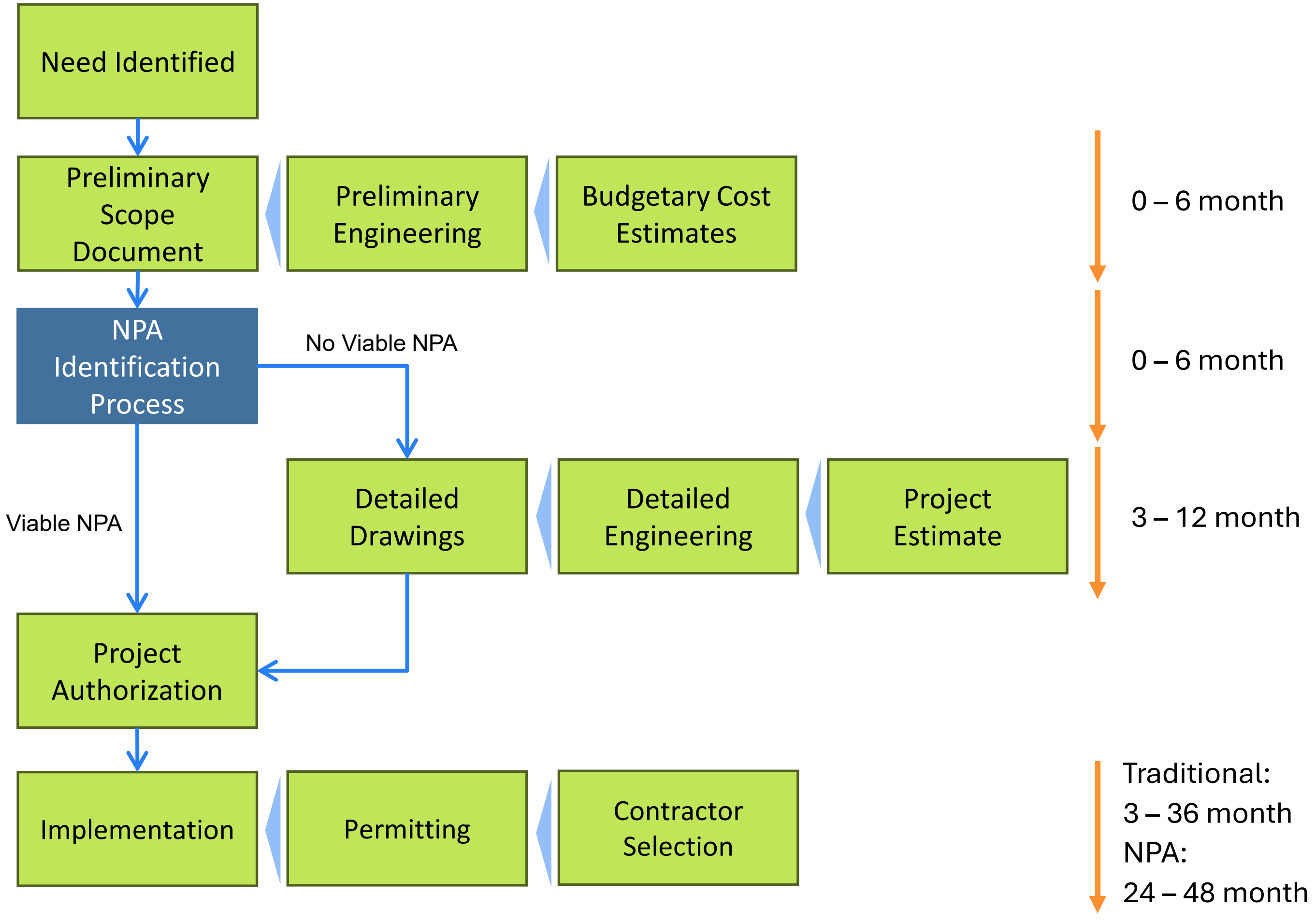
Project Authorization

Project Prioritization

Project Execution

The Companies shall initiate the NPA Identification Process as defined in this NPA Framework for all projects identified as requiring such review.

- Long-term plans are a long-range outlook on system needs.
- Individual projects are developed in consideration with site-specific and system-specific conditions to advance the long-term plans.
- Long-term and individual projects are assessed at regular intervals.
  - Typically, yearly during capital budget development.
- Where possible, each LDC shall incorporate consideration of NPAs and NPA assessments into its long-term system planning and goal development.



Timelines highly dependent on project type and size and experience with the NPA Process

Project Identification (4/4)

- **Project Identification**
- Initial Viability Testing
- System Feasibility Review
- Electric System Review
- Benefit Cost Analysis
- Project Authorization
- Project Prioritization
- Project Execution

The Companies shall initiate the NPA Identification Process as defined in this NPA Framework for all projects identified as requiring such review.

The Companies shall review viable NPA candidates with the following NPA technologies and solutions, or combination of solutions, as defined in Table 2 and provide results of said evaluation.

- The NPA Identification Process will consider a wide array of NPA technologies and solutions, depending on the program type.
- The LDCs will review the viable NPA candidates with the following technologies and measures:
  - **Electrification such as Air Source or Ground Source Heating Pump**
  - **Thermal Network Systems**
  - **Energy Efficiency & Demand Response**
  - **Behavior Change and Market Transformation**
  - **Supply Side Solutions**
- The Companies will also evaluate any combination of technologies listed
- Technologies and solutions will be updated with the Framework as they evolve

Reference: Table 2) NPA Technologies and Solutions

Program	Electrification	Thermal Network Systems	Energy Efficiency & Demand Response	Behavior Change and Market Trans-formation	Supply Side Solution	Asset Rehabilitation	Traditional Gas System Investment
GSEP	✓	✓	NA	NA	NA	✓	✓
Reliability - Capacity	✓	✓	✓	✓	✓	✓	✓
Reliability - Replacement	✓	✓	NA	NA	NA	✓	✓
Gate & Regulator Stations	✓	✓	✓	✓	✓	✓	✓
LNG/LPGA	✓	✓	✓	✓	✓	✓	✓
Resiliency	✓	✓	NA	NA	NA	NA	✓
New Customer Request	✓	✓	NA	NA	NA	NA	✓
DOT/Municip al Relocations	✓	✓	NA	NA	NA	NA	✓
Master Meter Compliance	✓	✓	NA	NA	NA	NA	✓

Initial Viability Testing (1/2)

- Project Identification ✓
- **Initial Viability Testing**
- System Feasibility Review
- Electric System Review
- Benefit Cost Analysis
- Project Authorization
- Project Prioritization
- Project Execution

All projects within the applicable programs will be run through an initial viability test to evaluate if projects are viable NPAs candidates.

- The LDCs shall proactively identify and evaluate projects to increase the likelihood of identifying viable NPAs.
- Testing is based on a variety of factors, including:
  - The safety and reliability concerns tied to the project
  - Timing of project need
  - Customer composition
  - Total project cost relative to customers impacted

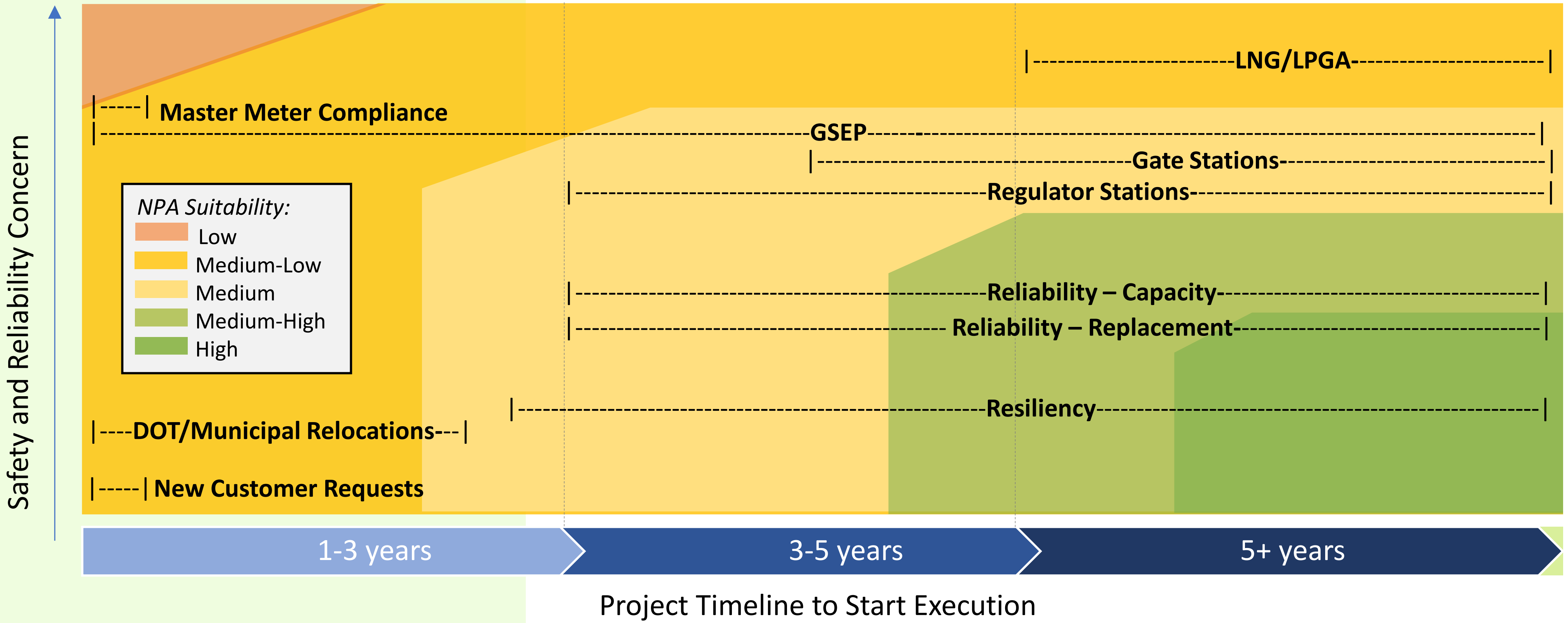
- Each LDC will propose certain thresholds to assist in identifying appropriate candidates with a high likelihood of success and ensure those are prioritized.
- The LDCs will provide their Initial Viability Testing Criteria as they evolve based on experiences gained as part of cost recovery filings to provide the Department with an avenue to continuously evaluate the Companies' Initial Viability Testing Criteria.

Initial Viability Testing (2/2)

- Project Identification
- **Initial Viability Testing**
- System Feasibility Review
- Electric System Review
- Benefit Cost Analysis
- Project Authorization
- Project Prioritization
- Project Execution

All projects within the applicable programs will be run through an initial viability test to evaluate if projects are viable NPAs candidates.

- Certain programs (and projects within programs) will show a higher success rate for NPA development than others.
- The NPA Opportunity Matrix suggests how each program fits within the NPA Suitability Score specifically to impacts of timing and safety and reliability concerns.



System Feasibility Review

- Project Identification
- Initial Viability Testing
- **System Feasibility Review**
- Electric System Review
- Benefit Cost Analysis
- Project Authorization
- Project Prioritization
- Project Execution

Gas System Integrity Review

For all projects which pass the Initial Viability Testing, the Companies shall produce a System Integrity Review. LDCs may also conduct a Customer Viability review following the Gas System Integrity review to gauge the likelihood that customers would be willing and able to electrify.

- The objective of this review is to determine if the gas system can function safely without the investment the NPA is looking to displace.
- This review may include an analysis using a hydraulic model to simulate system flow on the highest demand days and show the impact that decommissioning or not replacing a segment will have on the overall system. This step may include a re-scoping of the project area.

Step Zero Electric System Review

For all projects which pass the Gas System Integrity Review, the Companies shall work with the corresponding electric distribution system operators to attain a Step Zero Electric System Review.

- This review is to determine if the electric system can safely and reliably serve the additional load, and the level of investment needed (Step Zero Review).
- These Step Zero Reviews are developed by the electric distribution system operators and will provide the LDC with information on required system investments and timelines to completion of said investments.

Electric System Review

- Project Identification
- Initial Viability Testing
- System Feasibility Review
- **Electric System Review**
- Benefit Cost Analysis
- Project Authorization
- Project Prioritization
- Project Execution

For every project which passes the system feasibility review, the Companies shall request an Electric System Impact Assessment from the relevant electric distribution system operators. This electrification impact assessment shall include, at a minimum, cost and timing estimates for any required electric system upgrades.

- The LDCs will engage the electric distribution system operators to review load increases as a result of an NPA solution as required by the Step Zero Electric Analysis
- The system impact assessment will also include cost and timing estimates for any required electric upgrades.
- Customer and system data must be provided to the electric distribution system operators for them to do a system impact assessment.*
- The electric distribution system operators will provide the electric rate impact test (eRIM) as part of the BCA.

*__Note__: The LDC may only provide information to the electric distribution system operators which is covered by the Data Waiver the Companies have requested from the Department, an NDA is signed by the electric distribution system operators in question, or the information is generally publicly available. Data Waiver pending Department approval.

Benefit Cost Analysis (1/2)

Project Identification
Initial Viability Testing
System Feasibility Review
Electric System Review
Benefit Cost Analysis
Project Authorization
Project Prioritization
Project Execution

- The Department's Order directs the Companies to conduct a benefit cost analysis (BCA) to evaluate NPAs. D.P.U. 20-80-B, at 98 n.66.

For every project which passes the initial viability test and the Electric System Impact Assessment, the Companies shall furnish a BCA that includes one or more of the following tests as appropriate - a gas and electric rate impact measure (RIM), a participant cost test (PCT), and a total resource cost test (TRC). For the TRC, the Companies shall use the most currently approved TRC in the 3-year Energy Efficiency Plan with all applicable values.

Participant Cost Test

Cost	Benefit
Behind the Meter Costs such as heating systems, appliances, weatherization, electrical upgrades	Funding availability through the state's EE program
Increase in electric energy bills	Federal and other non-EE related incentives, tax benefits, grants, or funding opportunities
	Behind the Meter investment
	Electric rate subsidies made available through the NPA Project

Gas Rate Impact Measure

Cost	Benefit
Lost Revenue from electrified customers	Avoided revenue requirements stemming from the avoided capital investments.
Remaining Capital Investments and the resulting net present value revenue requirements.	Avoided gas supply cost through a demand-reduction induced price effect (DRIPE)

Electric Rate Impact Measure

Cost	Benefit
Net present value revenue requirements from incremental capital investments	Increased electric revenues from electrified customers
Negative electric supply cost impact from reverse demand-reduction induced price effect (DRIPE)	

Total Resource Cost Test

Cost	Benefit
Project Implementation Cost	Electric Avoided Costs
Performance Incentive Costs	Gas Avoided Costs
Project Participation Cost	Delivered Fuel Avoided Costs
	Other Resource Benefits
	Non-Energy Impacts
	Social Cost of Carbon

Benefit Cost Analysis (2/2)

- Project Identification
- Initial Viability Testing
- System Feasibility Review
- Electric System Review
- **Benefit Cost Analysis**
- Project Authorization
- Project Prioritization
- Project Execution

The Companies shall consider all funding sources for any NPA undergoing BCA evaluation, including reallocation of funds from different value streams within the NPA, so long as it does not turn any BCA negative.

Companies will pursue a viable, cost-effective NPA with the BCA tests ≥ 1. If the Companies proceed with an NPA which has failed one or more of the BCA tests, the Companies shall document sufficient evidence in support of their decision to proceed.

- The Companies may offer incremental funding for NPA Projects to help offset the costs for customers. These incremental funds, which may include grants and other outside funding, must be accounted for in the appropriate BCA.

- Companies will pursue a viable, cost-effective NPA. A cost-effective NPA is defined as an NPA with BCA tests ≥1. However, the Companies may also consider proceeding with an NPA if one or more BCAs are negative as long as the remaining BCAs are positive, the project is not cost-prohibitive, and other external circumstances make the NPA the more favorable option.

Project Authorization

- Project Identification ✓
- Initial Viability Testing ✓
- System Feasibility Review ✓
- Electric System Review ✓
- Benefit Cost Analysis ✓
- **Project Authorization**
- Project Prioritization
- Project Execution

The Companies shall update their project authorization forms to include an NPA review section for all project types listed in Table 1. For each of these projects, this NPA review section shall include the results of each review process step undertaken for the project. If a project fails the review process, documentation up to the point in the NPA Identification Process must be provided.

- All Companies have internal project authorization and approval processes which approve solution design and budget allocation to a specific project. These processes generally include a documented Project Authorization Form which outlines the need, impact of the need, the preferred solution, and all alternatives considered.

- The Companies will be updating these documentation and authorization process to include the NPA Identification Process and projects will only be able to proceed to implementation if they have provided sufficient evidence through the NPA Identification Process.

Project Prioritization

Project Identification

Initial Viability Testing

System Feasibility Review

Electric System Review

Benefit Cost Analysis

Project Authorization

Project Prioritization

Project Execution

If NPA projects must be prioritized for execution, the Companies shall prioritize the projects by and in the order of their impact to EJCs, avoided GHG emissions, and avoided gas capital. Prioritization will also consider project need and timing, ability to execute, customer needs, and other factors that may impact project success, such as the need to coordinate with state or municipal work.

If more NPAs are identified than can be reasonably implemented in a specific timeline the Companies shall consider prioritizing their NPA projects in this order:

I. Projects in EJCs will be given highest priority.

II. Projects will then be prioritized based on their net avoided GHG emission reductions.

III. Projects will lastly be prioritized based on the amount of avoided capital on the LDCs system.

This prioritization ensures focus on NPA efforts in alignment with stated objectives and directives.

Prioritization should also take note of timeline needs, compliance obligations, state and municipal project coordination, and customer specific issues that may impact execution timeline

Project Execution

Project Identification ✓

Initial Viability Testing ✓

System Feasibility Review ✓

Electric System Review ✓

Benefit Cost Analysis ✓

Project Authorization ✓

Project Prioritization ✓

Project Execution → **Customer Engagement** → **Impacts to Project Implementation**

Customer Education, Engagement and Commitment

Customer Education, Engagement and Commitment

New Customers

Existing Customers

The Companies shall engage all new gas customer requests with alternative options and require each customer to sign the “Customer Acknowledgement” form that they have been informed and have chosen to proceed with gas or an NPA solution.

- Each LDC has implemented a process to educate prospective customers about alternatives to natural gas.
- The LDCs requests these potential customers examine alternative options prior to agreeing to new natural gas service.
- Customers are required to sign a “Customer Acknowledgement” form, acknowledging their awareness of non-gas options available to them and their decision to move forward with natural gas before the LDCs will proceed with the installation of a new gas service or additional gas equipment.
- Residential single service and small commercial service requests:
  - Provided with the form describing non-gas options. LDCs may make information available via links to MassSave or a company web page
- Residential subdivisions and large commercial and industrial customers:
  - Provided with the form and the LDC will discuss project-specific alternatives with these customers.

Customer Education, Engagement and Commitment

New Customers

Existing Customers

Each Company shall develop a Customer Engagement Framework informed through the targeted electrification pilots

- The success of implementing NPAs depends on customers exercising their choice to adopt an alternative energy option.
- LDCs have an obligation to provide safe and reliable service to their customers.
- The LDCs are committed to engaging with customers regarding the availability of NPAs which can avoid potential stranded investments while providing safe and reliable service to remaining customers at an affordable cost.
- Each LDC will develop a customer education, engagement and commitment process to ensure that customers have sufficient information available to make an informed decision to participate in the NPA project.
- Each LDC will work closely with its customer and energy efficiency teams to develop an engagement strategy which fits its customer base, geographic region and demographics best, while setting a specific priority on EJCs.
  - The LDCs intend to apply lessons learned from their upcoming Pilots to this process.
- LDCs expect to gain an understanding of customer reactions and concerns associated with full removal of natural gas service, as well as effective education strategies.

Impacts to Project Implementation

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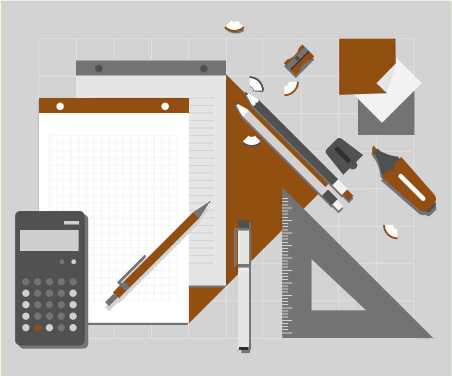
Impacts to Project Implementation

CLF 1-3

Non-Gas Customers

Changes in Project Viability

The Companies will only consider the natural gas customers within an NPA Service Area at time of project authorization.



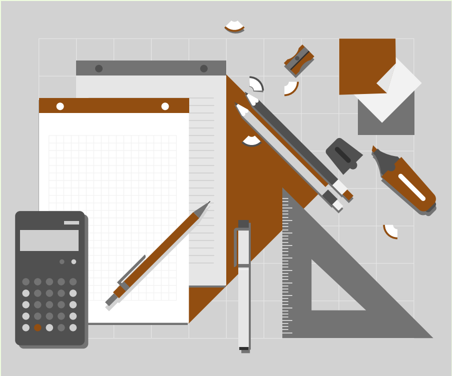
- There will be customers, within a NPA Project area, that do not have natural gas service or have certain applications on delivered fuels.
- As part of an NPA, the LDCs will only consider these customers which are required to avoid the traditional gas investment.
- Incremental and project specific funding made available by the LDCs for an NPA Project will not be made available for non-gas applications.
- During the NPA implementation period, the LDCs would not be accepting new gas connections in the discrete NPA project area.

Impacts to Project Implementation

Non-Gas Customers

Changes in Project Viability

The Companies may evaluate the NPA in the event of emergent situations or changes in customer participation. The Companies shall make all necessary investments to deal with emergent situations where applicable without impacting the prudency review of the NPA decision.



- Unpredictable circumstances:
  - Emergent field conditions may force an LDC to make unplanned system investments
  - The required level of electrification to avoid the gas capital investment cannot be met due to changes in customer commitment

Circumstances	Examples	Cancellation Criteria
Company/Asset Condition	Emergency gas pipe issue	Requires new asset investment negating the economics of the NPA/BCA
	Estimated cost increases	Cost increases negates economics of the NPA/BCA
Customer Participation	Customer terminates their participation	Entire NPA scope cannot be completed; Company may choose to offer remaining customers option to electrify
	New property owner refuses to participate	

Framework Updating

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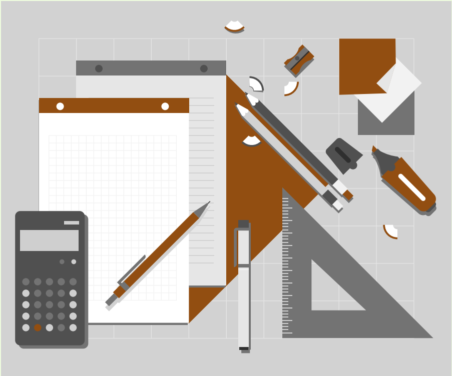
Framework Updates

Updates

The Companies are required to update the NPA Framework at a minimum every 5-years and submit the updated version to the Department for review with each CCP filing. Specifically, the Companies shall provide updates on technologies and solutions which may act as NPAs, the BCA, and Community Engagement topics. The Companies shall solicit stakeholder feedback for each iteration it submits to the Department.

- Regular updates to the Framework as experiences are gained through the process.
- A specific update cycle will allow for consistency and the chance to make updates with lessons learned.



- The LDCs will provide an updated NPA Framework, if appropriate, through the CCP filing process.
- The LDCs will work with stakeholders to make updates.

Summary of NPA Identification Requirements

Summary of NPA Identification Requirements (1-7)

Requirement Number	Requirement
1	The Companies shall initiate the NPA Identification Process as defined in this NPA Framework for all projects identified as requiring such review.
2	The Companies shall review viable NPA candidates with the following NPA technologies and solutions, or combination of solutions, as defined in Table 2 and provide results of said evaluation.
3	All projects within the applicable programs will be run through an initial viability test to evaluate if projects are viable NPAs candidates.
4	For all projects which pass the Initial Viability Testing, the Companies shall produce a System Integrity Review. LDCs may also conduct a Customer Viability review following the Gas System Integrity review to gauge the likelihood that customers would be willing and able to electrify.
5	For all projects which pass the Gas System Integrity Review, the Companies shall work with the corresponding electric distribution system operators to attain a Step Zero Electric System Review.
6	For every project which passes the system feasibility review, the Companies shall request an Electric System Impact Assessment from the relevant electric distribution system operators. This electrification impact assessment shall include, at a minimum, cost and timing estimates for any required electric system upgrades.
7	For every project which passes the initial viability test and the Electric System Impact Assessment, the Companies shall furnish a BCA that includes one or more of the following tests as appropriate - a gas and electric rate impact measure (RIM), a participant cost test (PCT), and a total resource cost test (TRC). For the TRC, the Companies shall use the most currently approved TRC in the 3-year Energy Efficiency Plan with all applicable values.

Summary of NPA Identification Requirements (8-16)

Requirement Number	Requirement
8	The Companies shall consider all funding sources for any NPA undergoing BCA evaluation, including reallocation of funds from different value streams within the NPA, so long as it does not turn any BCA negative.
9	Companies will pursue a viable, cost-effective NPA with the BCA tests ≥ 1. If the Companies proceed with an NPA which has failed one or more of the BCA tests, the Companies shall document sufficient evidence in support of their decision to proceed.
10	The Companies shall update their project authorization forms to include an NPA review section for all project types listed in Table 1. For each of these projects, this NPA review section shall include the results of each review process step undertaken for the project. If a project fails the review process, documentation up to the point in the NPA Identification Process must be provided.
11	If NPA projects must be prioritized for execution, the Companies shall prioritize the projects by and in the order of their impact to EJCs, avoided GHG emissions, and avoided gas capital. Prioritization will also consider project need and timing, ability to execute, customer needs, and other factors that may impact project success, such as the need to coordinate with state or municipal work.
12	The Companies shall engage all new gas customer requests with alternative options and require each customer to sign the "Customer Acknowledgement" form that they have been informed and have chosen to proceed with gas or an NPA solution.
13	Each Company shall develop a Customer Engagement Framework informed through the targeted electrification pilots
14	The Companies will only consider the natural gas customers within an NPA Service Area at time of project authorization.
15	The Companies may evaluate the NPA in the event of emergent situations or changes in customer participation. The Companies shall make all necessary investments to deal with emergent situations where applicable without impacting the prudency review of the NPA decision.
16	The Companies are required to update the NPA Framework at a minimum every 5-years and submit the updated version to the Department for review with each CCP filing. Specifically, the Companies shall provide updates on technologies and solutions which may act as NPAs, the BCA, and Community Engagement topics. The Companies shall solicit stakeholder feedback for each iteration it submits to the Department.

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EXHIBIT TEP-2

TARGETED ELECTRIFICATION DEMONSTRATION PROGRAM

IMPLEMENTATION PLAN

Targeted Electrification Demonstration Program Implementation Plan

Boston Gas Company
Massachusetts Electric Company and
Nantucket Electric Company
each d/b/a National Grid

December 6, 2024

Docket No. D.P.U. 24-194

Submitted to:
Massachusetts Department of Public Utilities

Table of Contents

Executive Summary

Boston Gas Company ("Boston Gas") Massachusetts Electric Company ("Mass. Electric) and Nantucket Electric Company ("Nantucket") each d/b/a National Grid (together the "Companies") are committed to enabling a fair, affordable, and clean energy transition and to helping the Commonwealth of Massachusetts ("Commonwealth") meet the nation-leading decarbonization goals established in the 2050 Clean Energy and Climate Plan. Meeting those goals will require not only an acceleration in the adoption rate of clean energy technologies, but also a transition from fossil fuel-powered appliances and equipment to electric alternatives.

In its *Order on Regulatory Principles and Framework*, issued on December 6, 2023, in D.P.U. 20-80-B, the Department of Public Utilities ("Department") expressed its optimism that "targeted electrification through decommissioning parts of the gas system may serve as a promising approach to reaching the Commonwealth's GHG [greenhouse gas] emissions targets," but also acknowledged that there are "several operational constraints and unknowns" related to targeted electrification. To gain a better understanding of those opportunities and constraints, the Department directed each gas local distribution company ("LDC") in the Commonwealth to "work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory."[1]

[1] *Order on Regulatory Principles and Framework*, D.P.U. 20-80-B, p. 87.

In response to that directive, and in order to test one method for accelerating the clean energy transition, the Companies hereby submit this Targeted Electrification Demonstration Program ("Demonstration Program" or "Program") Implementation Plan ("Implementation Plan"). The Demonstration Program's objective is to gain a better understanding of the opportunities and barriers of targeted electrification by attempting to decommission segments of leak-prone pipe in two municipalities through coordinated, voluntary customer electrification. In the process, the Companies hope to better understand what encourages, deters, or prevents customers from electrifying their homes, and to better understand the capabilities, analysis, and strategies that will be needed to shape the effectiveness of future non-pipeline alternatives ("NPA"). The Companies are currently engaged in the process of developing the Massachusetts NPA Framework in collaboration with stakeholders. The Companies expect that the NPA Framework will continue to evolve over time as learnings are gained and incorporated.

The Companies recognize that the implementation of NPAs is complicated and that there are many potential barriers to adoption that are exacerbated when attempting to coordinate adoption. However, in order to tackle these challenges, the Companies believe that "live learning", agility and rapid iteration can accelerate innovation in development and scaling of solutions. Therefore, while the Companies have designed a detailed Implementation Plan, they intend the Demonstration Program to allow for flexibility to adapt to customer needs to achieve the outcome of decommissioning leak-prone pipe segments.

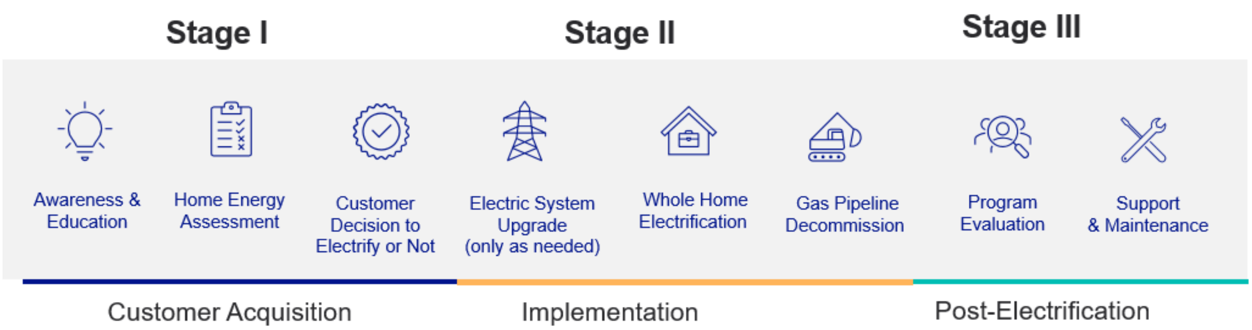
The Companies have designed the Demonstration Program to reduce key customer barriers to electrification:

Table 1. Potential Customer Barriers to Home Electrification

Potential barrier to adoption	Targeted Electrification Demonstration Program Design
Upfront cost of electrification	The Demonstration Program will address the full upfront cost of weatherization, pre-weatherization and pre-electrification barriers, and all-electric appliances.
Potential utility bill increases	The Demonstration Program will offer customers a bill credit to mitigate utility bill increases resulting from switching from gas to electric appliances.
Lack of familiarity with, and/or trust in, electric appliances	As part of the Demonstration Program design, with the support of trusted contractors, the Companies will engage in deep customer outreach and education, including educational community events, door-to-door engagement, marketing materials to educate customers on electric appliance use, benefits, and maintenance, and peer-to-peer neighborhood engagement through "heat pump champion" customers who sign up early for the Demonstration Program and who are converted regardless of whether or not their street segment advances.
Confusing / overwhelming process	The Demonstration Program will include a turnkey process to guide customers through the entire home electrification process. Each customer will work with a trusted contractor to manage the entire process, from the home energy assessment and selecting appliances to scheduling work and completing weatherization and equipment installation.

Figure 1 below illustrates, at a high level, the main stages of the Demonstration Program: Customer Acquisition, Implementation, and Post-Electrification.

Figure 1. Targeted Electrification Demonstration Program – High Level Program Stages



Specifically, the Demonstration Program will offer an opportunity to switch from gas appliances (e.g., furnaces or boilers, water heaters, dryers, and stoves) to all-electric appliances at no upfront cost, to 118 customers on 14 segments of leak-prone pipe in Leominster and Winthrop. Eligible customers will be offered:

- Home energy assessments
- Weatherization, including remediation of pre-weatherization barriers
- Cold-climate air-source heat pump (“ASHP”)[2] systems, including remediation of pre-electrification barriers
- Electric appliances to replace all other existing gas-fired equipment, including water heaters, dryers, and stoves
- Education and tips for efficient use of all new electric appliances
- Smart thermostats, compatible with the Mass. Electric’s ConnectedSolutions Demand Response program
- Smart panels to replace the electric panel, for managing and optimizing electric demand, and real-time electric usage data visibility and control at the circuit level (customers may opt out)

[2] Air source heat pumps are described as the Department of Energy as “An air-source heat pump can provide efficient heating and cooling for your home. When properly installed, an air-source heat pump can deliver up to two to four times more heat energy to a home than the electrical energy it consumes. This is because a heat pump transfers heat rather than converting it from a fuel, like combustion heating systems.” Department of Energy, (n.d.), *Air-Source Heat Pumps*, Air-Source Heat Pumps | Department of Energy.

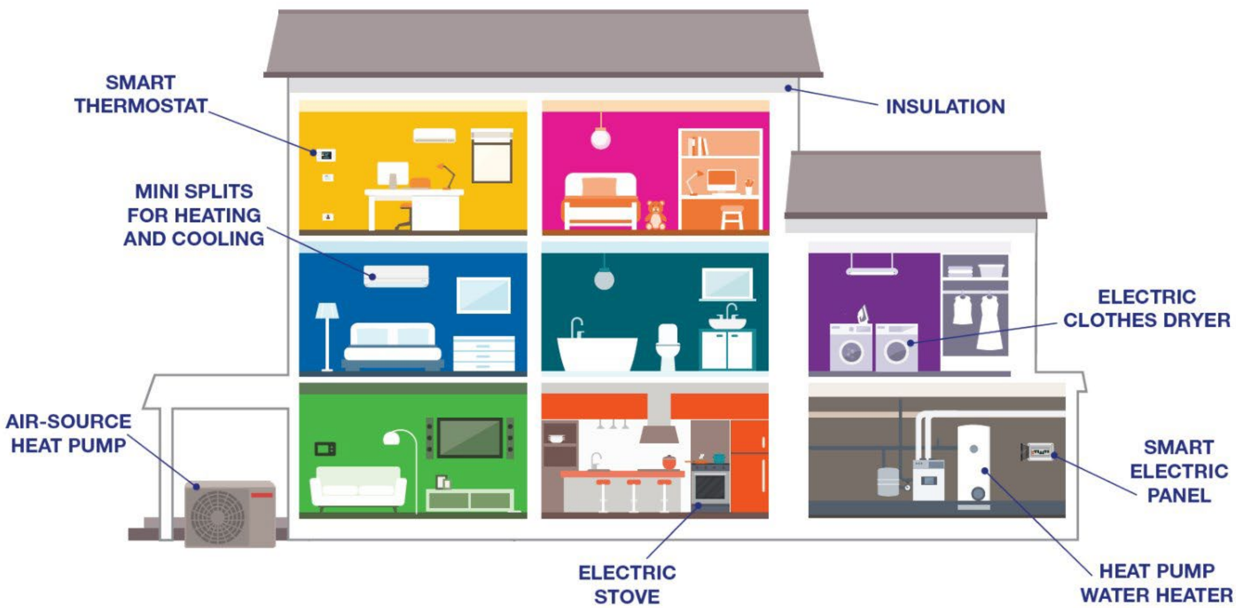
- Post installation support for service and maintenance of the ASHP for 2 years and standard appliance warranties for the other appliances
- A monthly bill credit to help alleviate potential impact of higher net energy bills

For customers to receive the Demonstration Program incentives, 100% customer participation on a given segment is required (or, alternatively, participation from a continuous group of customers located at the end of a segment such that part of a segment can be decommissioned), so that the planned gas system decommissioning benefits can be realized.

Funding will leverage Mass. Electric's existing Mass Save® Residential Turnkey Services ("Mass Save") and Income Eligible incentives for customers for home weatherization, heat pumps, and other electric appliances. Costs not covered under the Mass Save program will be funded and recovered as part of the Demonstration Program. The Demonstration Program costs, incremental to the estimated Mass Save incentive costs, are estimated at $1.0 million for program administration, $425 thousand for education, marketing, and outreach, and, if all targeted 118 customers on all 14 segments electrify, $8.9 million for customer incentives for full home electrification, ~$600 thousand for bill credits over 5 years, $26 thousand for O&M associated with electric network upgrades, and $300 thousand for EM&V, for a total maximum cost of $11.3 million. The Demonstration Program costs are dependent on customer participation and will be commensurately lower if not all eligible customers choose to participate.

Figure 2 below illustrates the type of mechanical equipment that may be installed at the homes of participating customers to meet their energy needs. The exact types of mechanical equipment will depend on the gas appliances the customer is currently using, and the layout and energy needs of the home, both of which will be determined during the home energy assessment. Only gas equipment and appliances needed to disconnect from the segment will be replaced through the Demonstration Program.

Figure 2. Illustrative Electric Home Conversion



Section 1 of this Implementation Plan describes the Demonstration Program's background and goals, including an overview of the requirements contained in the D.P.U. 20-80-B Order, the Demonstration Program's alignment with Mass. Electric's recently approved Electric Sector Modernization Plan[3], and a deep dive into the Demonstration Program's goals. Section 2 then

[3] *Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future*, January 2024, D.P.U. 24-11. Available at https://www.nationalgridus.com/Our-Company/MA-Grid-Modernization

delves into the design of the Demonstration Program, including the scope of the offering to customers, the customer engagement and outreach plan, contractors' scope and selection, the Demonstration Program timeline, and other Demonstration Program details. Section 3 describes the criteria that the Companies followed in selecting municipalities for consideration for inclusion in the Demonstration Program and selecting segments of leak-prone pipe located within the selected municipalities. Section 4 details the analysis of the electric grid conducted by the Companies to assess impacts associated with customer electrification on those segments. Section 5 then explores the Companies' plan for internal and external engagement regarding the Demonstration Program. Finally, Section 6 provides estimates of Demonstration Program costs.

1. Demonstration Program Background & Goals

Traditionally, there has been little need for coordination between gas and electric utilities due to the ways in which customers have used the networks, and, as such, gas and electric utilities have generally planned and operated their networks in isolation from one another. Since the D.P.U. 20-80-B Order directs all LDCs to evaluate all gas investments moving forward, coordinated and comprehensive integrated energy planning ("IEP") between electric and gas utilities, including identifying opportunities to target deployment of heat electrification in ways that avoid specific gas and/or electric network investments, will be critical in reaching the Commonwealth's decarbonization goals.[4] IEP will also provide a more informed understanding of the total energy

[4] See Section 11 of Mass. Electric's *Electric Sector Modernization Plan*, D.P.U. 24-11, p.457-464, for more detail on the Companies' approach to IEP.

system, both gas and electric, so that decisions can be made that consider implications to both systems, provide for a more reliable and affordable whole energy system, and optimize societal benefits and costs. This Demonstration Program aims to develop critical learnings on customer adoption of electrification and capabilities that will be an essential step forward into the future of IEP.

The Companies submit this Demonstration Program Implementation Plan in compliance with D.P.U. 20-80-B and in alignment with the IEP vision laid out in Mass. Electric's Electric Sector Modernization Plan. The Demonstration Program also continues the collaboration between the Companies that commenced in 2022 to assess optimal locations to electrify residential customers in the Companies' overlapping gas and electric service territories (locations containing segments of LPP where targeted electrification would enable pipeline retirement with minimal anticipated impact to the electric grid).

1.1 Overview of D.P.U. 20-80 Requirements

In its December 2023 Order D.P.U. 20-80-B, the Department instructed the LDCs to "work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory" and for each LDC to file a project proposal by March 1, 2026.[5] Each LDC is expected to target a portion of its system that (1) suffers from pressure/reliability issues, (2) includes leak-prone pipe, and/or (3) includes environmental justice

[5] D.P.U. 20-80-B at 87.

populations that have borne the burden of hosting energy infrastructure. The Department further states that in reviewing a proposed demonstration project, it will consider the: (1) reasonableness of the size, scope, and scale of the proposed project in relation to the likely benefits to be achieved; (2) adequacy of the evaluation plan; (3) extent to which there is appropriate coordination among Program Administrators; and (4) bill impacts to customers, among other things.[6] The Department expected the LDCs to engage with elected and appointed officials in the community, community-based organizations that work on energy, environment, labor, or ending poverty, and other interested residents.[7]

1.2 Alignment with Electric Sector Modernization Plan

Section 11 ("Integrated Gas-Electric Planning") of the Electric Sector Modernization Plan outlined the importance of integrated energy planning, its vision for it, the many challenges to successfully executing on a new way of working across gas and electric utilities, and the types of coordinated processes that will be needed going forward.[8] As part of that vision, Mass. Electric identified a significant role for IEP in "direct[ing] Massachusetts homes and businesses toward electrification when the opportunities arise (e.g., at end of life for a legacy fossil heating system)."[9] It further noted that "the full electrification of gas customers not coupled with the necessary electric

[6] D.P.U. 20-80-B, at 88.
[7] Id.
[8] *Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future*, January 2024, D.P.U. 24-11. Section 11 at 456-64. Available at https://www.nationalgridus.com/Our-Company/MA-Grid-Modernization.
[9] Id., at 457

infrastructure improvements will result in an unreliable grid; conversely, there may be opportunities to locally target deployment of heat electrification in ways that avoid gas network investments."[10]

1.3 Demonstration Program Goals

The Companies' designed the Demonstration Program with the following goals in mind:

1) Comply with the directives in the D.P.U. 20-80-B Order;
2) Attempt to decommission one or more leak-prone gas pipe segments through coordinated whole-home electrification of customers, in environmental justice communities if possible;
3) Increase understanding of customer sentiment towards electrification;
4) Ascertain the Companies' ability to influence customer sentiment and participation through a variety of methods, including financial incentives, to help inform future customer engagement for scaling of NPAs; and
5) Develop learnings regarding internal capabilities, processes and assumptions needed to successfully deliver future NPAs and targeted electrification at scale, including gas segment identification, customer acquisition, and electric grid peak impact analysis.

[10] Id., at 457

To enable these learnings, the Companies are taking an "agile" design approach, moving quickly and with the intent to adapt to what is and is not working to generate customer interest and participation.

1.4 Learnings from Other Targeted Electrification Efforts

In developing the Demonstration Program, the Companies leveraged and incorporated learnings from what has worked and not worked for other targeted electrification efforts across utilities, including their New York affiliates, other US utilities, as well as international utilities and municipalities engaged in clean heat planning.

In New York, the Companies' affiliates (Niagara Mohawk Power Corporation in upstate New York and The Brooklyn Union Gas Company and Keyspan Gas East Corporation in downstate New York) have been working over the past two years to identify planned gas capital projects that potentially could be avoided through targeted electrification and decommissioning of specific segments of aging gas infrastructure rather than replacement. Beginning in 2022, the Companies' New York affiliates began contacting customers along segments of LPP to assess their willingness to transition to electric solutions and to disconnect from gas. This outreach conducted by a vendor working on behalf of the Companies' New York affiliates involved surveying some customers (i.e. contacting customers to understand their awareness of and interest in alternatives) and presenting NPA offers to some customers by contacting them with an NPA incentive offering and recording their decision of whether or not to accept it. Specifically, the vendor reached out to survey 144 customers along 12 segments of LPP, all but 3 segments of are in New York[11] and employees of the Companies' New York affiliates contacted 441 customers along 30 segments of LPP to present them with NPA incentive offers. On one of these 30 segments that serves only two customers, a customer at the terminus end of that segment has committed to disconnect, meaning truncation of the segment will be feasible. If the other customer on this segment also agrees to disconnect, retirement of the full segment will be possible. The Companies' upstate New York affiliate also identified 19 farm taps planned for replacement with an updated design that served individual customers. This presented an opportunity for each customer to adopt an NPA independent of the decisions of the other customers. Of the 19 customers, 3 customers ultimately adopted the NPA and were disconnected from the gas system. The results of the outreach to the 42 LPP segments that were surveyed and those that were presented with an offer and did not achieve full participation for an NPA indicate limited customer interest to be a barrier, with roughly 10% of customers expressing interest in learning more or converting any of their appliances and a smaller amount expressing willingness to convert their space heating. Those that expressed interest have been scattered across the potential NPA segments, highlighting the challenge of coordinated interest and participation among neighbors.

[11] A vendor, DNV-GL, which was hired by the Companies' New York affiliates contacted 34 customers along 3 streets in Massachusetts in 2022 in addition to contacting customers along 9 streets in New York. This outreach was to assess customer awareness of and interest in transitioning to non-gas solutions. Out of these 34 customers in Massachusetts, only 7 customers responded to outreach attempts and completed the survey.

Customer feedback as part of the New York affiliate's outreach identified several barriers, including a lack of broad customer familiarity with heat pump technologies, concerns about the impacts of electrification on their energy bills, customer preferences for certain types of gas appliances, and challenges aligning the gas infrastructure replacement timelines with timelines for customers' own equipment turnover. This Demonstration Program seeks to address some of those concerns, namely by including a comprehensive marketing and outreach campaign, using Heat Pump Champions to address the lack of familiarity, and a bill credit to address energy bill concerns.

In May 2024, National Grid and RMI, clean energy nonprofit formerly known as Rocky Mountain Institute, published *Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System*[12], a report that analyzed nine NPA case studies from the U.S. and Europe to better understand how they have been most effectively implemented and the challenges to scaling up these projects as part of the clean energy transition. The case studies revealed, among other key findings, that due to the challenge of achieving voluntary, coordinated adoption among customers on common gas infrastructure segments, successful NPAs have been limited to projects with five or fewer customers. With that in mind, the Companies have elected to prioritize leak-prone pipe segments with a smaller number of customers for this Demonstration Program.

12 *Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization* May 2024, RMI and National Grid, Available at: https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf

Findings from a June 2024 report[13] from the California Energy Commission together with PG&E show that community outreach, derived from stakeholder feedback including local governments and environmental justice organizations, is key to project success – on the premise that "local organizations would best understand the unique needs of local communities and the circumstances and conditions for specific pilot sites." The Companies are leveraging this approach in their customer and community engagement, including planned collaboration via the Winthrop Community First Partnership. The results of the report also highlighted that focus group participants were "supportive of the idea of developing an all-electric demonstration home in their neighborhood to show the viability of electrification," a key finding that the Companies leveraged in designing its Heat Pump Champion approach described in Section 2.4.2. Another December 2023 report from the California Energy Commission focused on Southern California, together with SoCal Gas and RAND, concluded that community engagement is critical to identifying location specific equity concerns, and thus critical to equitable decommissioning.[14]

The Companies also participated in a peer utility NPA workshop in October 2024, designed to share learnings and best practices on the development of an NPA program. Some key findings echoed other research and learnings cited above – namely that successful NPAs and targeted electrification have been limited to specific areas of the system with few customers, and that

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[13] https://gridworks.org/wp-content/uploads/2024/07/Targeted-Electrification-and-Strategic-Gas-Decommissioning.pdf
[14] https://ucla.app.box.com/v/RAND-CECprojectClose

community partnerships, advocates, and third-party surveys are valuable tools to engage with potential customers – all approaches the Companies are proposing to include in its Demonstration Program design, described further in Section 2.

2. Demonstration Program Design

The Demonstration Program will target 14 segments of LPP in Leominster and Winthrop, 8 of which are in environmental justice communities and will offer the 118 customers on those segments the opportunity to replace existing gas appliances (e.g., furnaces, water heaters, dryers, and stoves) with electric-powered appliances and disconnect from Boston Gas's gas system. All 118 customers who would be eligible for the Demonstration Program are in the Companies' overlapping service territories; i.e., they are customers of both Boston Gas and Mass. Electric.

Leak-prone pipe can be decommissioned only if 100% of customers (or a group of contiguous customers located at the end of a segment) served by that segment agree to disconnect, and in this case fully electrify. As other targeted electrification projects across the world have shown, achieving 100% customer participation can be challenging, even when generous incentives are provided.[15]

As such, the Companies have designed the Demonstration Program with four principles in mind. First, the Companies have targeted multiple leak-prone pipe segments to increase the

[15] *Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization* May 2024, RMI and National Grid, Available at: https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf

probability that a segment which all customers agree to disconnect can be identified. Second, the Companies designed the Demonstration Program to ensure that cost is not a barrier by covering the full upfront cost of home electrification and offering a bill credit for up to five years to defray resulting incremental energy costs. Third, the Demonstration Program will test novel marketing and outreach strategies, including Heat Pump Champions (see Section 2.3), leveraging community organizations and hosting community events, with a focus on learning about the most effective methods of engagement and what factors incent customers to electrify. Finally, flexibility and the ability to rapidly iterate using insights learned on customer preferences throughout the Demonstration Program will be critical to maximize the likelihood of LPP segment decommissioning and will generate a multitude of learnings for the Companies' iterative approach to NPAs at scale. This flexibility includes the ability to substitute segments in response to customer interest for alternative segments of comparable size and scope, adjusting the customer journey and illustrative customer forms.

The only successful NPAs in the United States to-date have covered the full upfront cost of electrification for customers. Experience from other regions, including California and New York, have shown low uptake even when the full upfront costs are covered, revealing other barriers that need to be overcome.[16] The Companies want to understand the non-cost barriers that still need to be overcome and have designed the Demonstration Program to ensure that both upfront costs

[16] *Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization* May 2024, RMI and National Grid, Available at: https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf

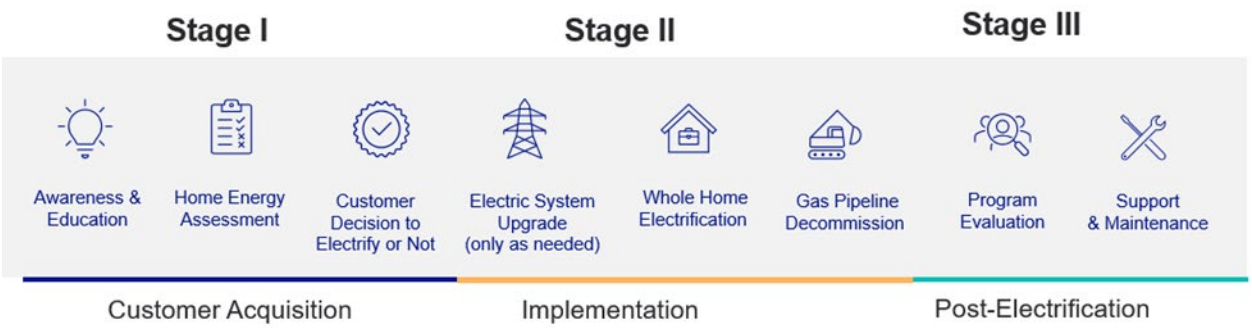
and ongoing operating expenses are not a hurdle, an especially important element given that 13% of the customers in these segments are low-to-moderate income. While the Companies recognize that covering the full upfront costs and offsetting net utility bill increases is unlikely to be cost effective for NPAs to scale, introducing customer costs as a barrier for this Demonstration Program would likely prevent the Company from learning about important non-cost barriers and engagement strategies.

The Companies expect that learnings from effective education and communication strategies, and local community engagement will inform future NPA efforts and the development of scalable NPA programs. The Demonstration Program has been designed with a focus on local community engagement, and includes an opportunity for local electrification leaders, called "Heat Pump Champions." Up to five customers will have the opportunity to become "Heat Pump Champions," and will receive the full home electrification offering, regardless of their neighbors' participation. These customers will host, along with the support of the Companies and its contractors, community events for their neighbors to help overcome a lack of trust and familiarity with heat pumps and other electric appliances and will serve as models to encourage participation by other customers.

The Demonstration Program will proceed in three general stages. Stage I will focus on customer and community research, education, and outreach and generating interest and excitement from potential participants with the goal of prompting customers to sign up for a no-cost Home Energy Assessment. The Home Energy Assessments offered through Mass Save will determine what is needed for full-home electrification, including identifying pre-weatherization and pre-electrification barriers, need for weatherization, the type and size of heat pumps, and the gas appliances that need to be replaced. This touchpoint provides the Lead Vendor an opportunity to review with the customer what they are eligible to receive at no cost and to invite the customer to sign a standardized customer participation agreement ("Customer Participation Agreement")[17]. Marketing and outreach efforts will adapt to customer interest, focusing on segments with the most demonstrated interest. Stage II will be the implementation of whole home electrification for any segments that reach full participation. Any needed pre-weatherization, pre-electrification, and weatherization work will be completed in this stage as part of the whole home electrification. Stage II includes electric system upgrades required to support the incremental electric load, whole home electrification of participating customers, and decommissioning of the gas pipe segment. Stage III will follow whole home electrification and include program evaluation, support, and maintenance. Each of these stages has multiple phases; phases may overlap and may proceed on somewhat differing timelines for individual customers and individual LPP segments.

[17] See Attachment A for Illustrative Customer Participation Agreement

Figure 3 Stage of Customer Engagment



2.1 Demonstration Program Benefits

The Companies designed the Demonstration Program to benefit the Commonwealth as a whole and the individual Demonstration Program participants. They foresee the following as benefits to the Commonwealth:

1. Learnings regarding what is required to drive targeted whole home electrification in a way that enables gas system decommissioning, which can be leveraged to help scale NPAs;
2. Avoided costs of replacing and maintaining leak-prone pipe for those segments that achieve sufficient customer participation to be decommissioned (refer to Table 3);
3. Reduction of GHG emissions associated with natural gas usage for customers who participate in the Demonstration Program of up to a 266 MT CO2 reduction if all customers participate (estimated at 2.3 MT CO2 reduction annually per customer);

4. Assessment of customer and community engagement strategies for interest in home electrification;
5. Creation of an example of community action towards decarbonization;
6. Demonstration of project economics for potential future targeted electrification efforts;
7. By retiring LPP segments, municipalities potentially experience a reduction in maintenance needed within the public rights of way; and
8. Action toward meeting the Commonwealths' climate goals articulated in the Clean Energy and Climate Plan.

For participating customers, the following are the Demonstration Program's benefits:

1. Weatherization and new high-efficiency heating and cooling system at no upfront cost, with free heat pump service and maintenance provided for two years;
2. Remediation of pre-weatherization and pre-electrification barriers (if necessary), including potential associated health and safety benefits (due to remediation of factors such as mold, asbestos, and others);
3. Improved comfort from weatherization and improved cooling for customers who do not have air conditioning or who have inefficient and inconvenient window units (85% of target customers do not have central air conditioning[18]);
4. Home improvements that make the participants' homes more valuable;

[18] See Table 2 "Customer Demographics"

5. Brand new, worry-free appliances;
6. Smart thermostat to help save energy and save money through the ConnectedSolutions program;
7. Optional installation of a smart electric panel to provide insight into data usage and to optimize demand to support whole-home electrification;
8. Logistical support from the Companies' Demonstration Program team and Lead Vendor, including help with equipment selection, system design, coordination of installation, and maintenance support for two years post electrification for ASHP and standard manufacturers' warranties for all other electric appliances;
9. Bill credits lasting up to five years to mitigate potential increases in energy costs that may result from participation;
10. For certain customers, relocation of heating equipment out of basements in flood-prone areas; and
11. Avoided future inconvenience and disruption of repairing leaks and replacing the gas pipe segment, including digging up and repairing the street.

2.2 Scope of Customer Offering

2.2.1 Whole Home Electrification

Before the switch from gas to electric appliances can occur, there are several steps that may need to be taken. Following an initial expression of interest in the Demonstration Program, customers will be contacted to schedule a Home Energy Assessment. The Home Energy Assessment will identify what appliances are eligible for replacement, weatherization needs, and the presence of any “pre-weatherization” or “pre-electrification” barriers. The first step is to address any “pre-weatherization” barriers – including asbestos, mold, outdated electrical wiring (e.g., knob-and-tube wiring), roof leaks, and/or general structural issues – that might be present in a customer’s home that must be remediated or addressed before other steps can be taken. If the home is not properly weatherized, there may be an additional step to adequately weatherize the home with the installation of measures such as insulation and air sealing; this is an important step that ensures heat pump systems can be properly sized and comfort maintained in the home. To ensure the home is ready to manage the increase in electric demand, the home’s electrical panel will be replaced with a smart electrical panel (see Section 2.2.2), which will also provide customers with additional insights and control over their electrical usage so they can better manage their electric bills and understand their new all-electric appliances. If a customer does not want a smart panel, they will receive a traditional electric panel with sufficient amperage to accommodate new electric loads.

Once barriers are addressed, weatherization is complete and the electric panel is upgraded, the replacement of gas appliances can occur. Gas furnaces or boilers will be replaced with cold-climate high efficiency air-source heat pumps due to their low cost (relative to ground-source heat pumps), proven performance, ease of installation, and ability to provide both heating and cooling. Heat pumps will be sized to meet each customer's full heating load and will follow weatherization to account for efficiency gains from a tighter building envelope. Gas-fired water heaters will be replaced with electric heat pump water heaters, and gas dryers will be replaced with electric models. For cooking, electric ranges (either induction or conventional electric) will be provided as replacements for gas-fired models, along with a stipend for new cookware required for induction cooking for those that select an induction range. For customers with gas fireplaces, electric inserts will be offered. Other gas appliances, such as natural gas grills, will be considered, as needed.

The Companies intend to make participation in the Demonstration Program easy for customers by managing most, if not all, elements of the conversion. Existing appliances and systems powered by non-gas fuels (e.g., oil or propane) or water heaters, stoves or dryers that are already electric will not be replaced as part of the Demonstration Program, since doing so would increase program complexity and expense without advancing the goal of eliminating participants' gas consumption. However, if customers wish to replace existing electric-powered appliances with more efficient models or replace existing propane or fuel oil systems with electric alternatives, the Companies and their Lead Vendors will direct them to National Grid's existing Mass Save incentives for more efficient equipment.

2.2.2 Smart Electrical Panel

Demonstration Program participants will be offered, but not required to install, a smart electrical panel. For the purposes of this Demonstration Program, the benefits of a smart panel include:

- Dynamic load-control, enabling electrification without a service upgrade at a cost the same or less than a traditional service upgrade.
- Actionable energy insights, alerts, and whole-home demand response capabilities, which can enable customers to save money through future time varying rate design and/or demand response programs.
- Load disaggregation, which can help customers understand how the various appliances in their home consume energy. These capabilities will provide customers with additional information and control over their electrical usage and help them understand their new all-electric appliances.
- The granular interval data provided by smart panels will enable the Companies and their EM&V contractor to evaluate the appliance-level impact of electrifying segments of customers on local distribution system peak load. This data will be valuable both for evaluation of the Demonstration Program and for gaining an understanding of the electric system impacts of targeted electrification at scale.
- From an electric grid perspective, smart panels may be a useful tool to help to manage peak loads by enabling customers to reduce or shift circuit-level energy usage during electric

grid peaks, limiting each home's peak load consumption or optimizing peak demand across homes. This in turn could help to minimize the need for future electric distribution network upgrades at the distribution transformer, feeder, or even substation level. For the purposes of this Demonstration Program, participating customers interested in a no cost smart panel would also enable the Companies to assess the effectiveness of smart panels as a peak demand management tool alongside whole home electrification (see section 4.5 for more detail).

The smart panel vendor will be selected via competitive solicitation.

2.2.3. Support and Maintenance

To ensure success of the Demonstration Program, the Companies propose a support and maintenance plan for two years post full home electrification, including annual maintenance, inspection and cleaning of the heat pump system. With the turnkey model, the Companies want to ensure that each participating customer best understands the workings of their new appliances and when to call for help. The Lead Vendor that completes the whole home electrification will guarantee materials and workmanship that meets or exceeds the specifications in the installation standards of Mass Save and will be responsible for the warranty on parts and service.

2.2.4 Bill Credit

Based on a preliminary analysis of expected energy consumption pre- and post-electrification and current rates for gas and electricity, the Companies estimate that many participants in the Demonstration Program are likely to experience higher total energy costs after electrification with current volumetric rate design.[19] To help offset those higher costs, the Companies propose that all participants receive a monthly bill credit for 5 years once their electric appliances are installed. As described in Section 2, the Companies designed this Demonstration Program such that cost is not a barrier to participation, but future efforts should evaluate customers' willingness-to-pay.

In response to the D.P.U. 23-150 Order, Mass. Electric and Nantucket Electric are developing a Heat Pump Rate, which will improve the economics of heat pump operation, and is expected to be implemented next year. The Heat Pump Rate will be applicable only to the delivery portion of the bill, not the supply portion, and the Companies' preliminary analysis suggests that a bill credit will still be needed. Participants in the Demonstration Program will be enrolled in the Heat Pump Rate and will receive a bill credit sized to offset the estimated increase in total energy costs under that rate.

[19] That analysis assumes an improvement in energy efficiency due to weatherization as part of the Demonstration Program and an efficiency gain from switching to an air source heat pump (COP of 3). The analysis does not assume any changes in participant behavior post conversion (e.g., there will be no increase in usage due to greater air conditioning usage).

The credit amount will be calculated to offset the estimated increase in participants' total energy costs (increase in total electric bills net of gas bill savings). The credit will be applied to the participant's monthly electric bill and will offset any positive balance (i.e., if there is a month where a participant has an electric bill of less than the credit amount, the credit will be carried forward to the next month).

2.3 Customer Engagement and Outreach Plan

Since the Demonstration Program relies on coordinated, voluntary participation, customer engagement and outreach will be essential to realizing the potential avoided LPP benefits associated with this Demonstration Program. Learnings from Companies' experience with their affiliates' NPAs in New York will be incorporated.

2.3.1. Customer Participation Requirements

To participate in the Demonstration Program, customers must:

- Have a current account with Boston Gas and Mass. Electric or in the case of a tenant-occupied building, the tenant(s) should have a current account with Boston Gas and/or Mass. Electric for the utility(ies) they are responsible for paying as part of their tenancy;
- Regardless of who has the Boston Gas and/or Mass Electric account, a of the Customer Participation Agreement must be signed by tenant and landlord for tenant occupied premises;

- Agree to weatherize the residence to standard energy efficiency program practices, if sufficient weatherization is not already present;
- Agree to replace all gas end uses in the residence;
- Allow reasonable access to the residence and sufficient time for the hired contractor to perform the electrification upgrades;
- Select replacement electric appliances from a menu of options, or cover the incremental cost of any such appliances if an “off-menu” option is desired (see Section 2.4.3 Equipment Selection/System Design for more information on this process);
- Comply with the timeline stipulated in the Customer Participation Agreement;
- Complete any surveys issued by the Companies for EM&V purposes;
- Consent to customer account information data sharing between Boston Gas, Mass. Electric, and any other contractor utilized by the Demonstration Program who require access to such data; and
- Agree to fully disconnect from the gas system.

Attachment A, the illustrative Customer Participation Agreement, lays out these requirements and other terms.

2.3.2 Customer Demographics

The customers eligible for participation in the Demonstration Program on the 14 segments in Leominster and Winthrop are predominantly homeowners (92%), with most (68%) in single-family homes, while 32% live in two- or three-family homes. As may be expected for homes located on segments of old, leak-prone gas pipes, the building stock is largely older homes, with 76% built before 1950. The average home in Leominster was built in 1943, while the average age of homes in Winthrop is 1914, with the oldest home dating from 1880. Older homes built before 1950 are typically not well-insulated and are more likely to need weatherization and are also more likely to have pre-weatherization and pre-electrification barriers, such as asbestos, mold, and/or outdated electrical wiring. The majority of homes (85%) do not have ductwork[20] and therefore are unlikely to have central air conditioning. This means that the benefit of efficient cooling from an ASHP may be a big value proposition for these customers.

Table 2: Customer Demographics

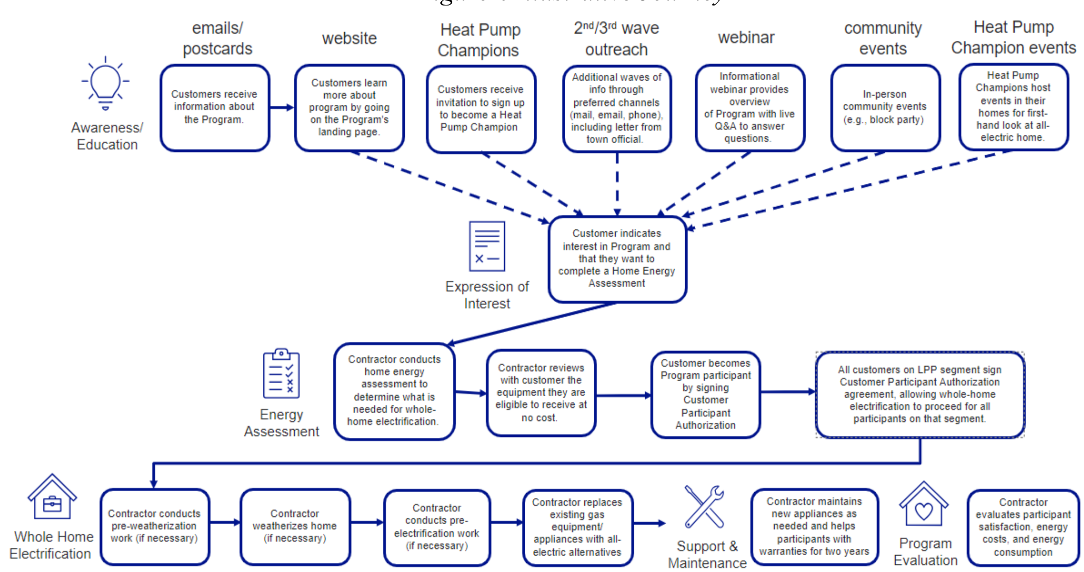
Town	Customer Count	% Single-family	% Owners	Pre-1950	Average age home est.	% No Central AC	% Non-heating	% Income Eligible
Leominster	50	79%	92%	60%	1943	86%	7%	4%
Winthrop	68	57%	92%	91%	1914	85%	5%	19%
Total	118	68%	92%	76%	1929	85%	5%	13%

[20] Based on heating system type. Assumes that homes with forced hot water, steam, radiant and baseboard heating systems do not have ductwork.

2.3.3 Customer Engagement and Outreach

The Companies will take a multi-modal approach to outreach and engagement to ensure that the customers have all the necessary information to make an informed decision about whether to participate in the Demonstration Program. All customers on the identified street segments will be engaged through various methods of marketing and outreach. An illustrative customer journey for customers engaged as part of the Demonstration Program is outlined in the figure below. This customer journey mapping was used in the development of the Demonstration Program engagement and outreach plan presented in this section. As the Companies further develop and refine the engagement and outreach plan, the customer journey is subject to change. As part of the agile program design, the Companies may also iterate and adjust the customer outreach approach to respond to what is and is not working to generate interest and participation.

Figure 4 Illustrative Journey



Informed by experience from Mass Save marketing efforts and learnings from NPA efforts in New York, marketing materials will need to be clear, educational, persuasive, and emphasize the value proposition for customers. For example, those materials will provide a clear summary of the Demonstration Program, clear articulation of benefits, a call to action that encourages potential participants to schedule a Home Energy Assessment, and contact information for the Demonstration Program team. A draft sample of the Companies' marketing collateral is provided as Attachment B. Marketing materials will seek to educate customers and proactively address potential customer concerns. To increase language access, the Companies will review the non-English language needs of the segments and translate the marketing materials for those customers. Marketing materials will be made available in print and digital formats. A project landing page will exist on the Companies' website for comprehensive Demonstration Program information, program manager contacts, education, and resources (accessible via a vanity URL, direct link and QR code).

Traditional Marketing Efforts

Marketing efforts will focus on:

- Educating customers about whole home electrification and its benefits, with particular attention to the benefits of efficient cooling provided by the ASHP (a significant benefit for many of the identified customers that do not have central air conditioning) and the benefits and features of induction cooking
- Informing customers about the details of the conversion process

- Communicating the financial incentives provided by the Demonstration Program
- Gauging interest in electrification
- Driving participation in the Demonstration Program

The specific channels, messaging, and collateral types will be chosen based on the results of the Companies' customer research and their engagement with local elected officials and community groups, and may include direct mail, e-mails, phone calls, and as referenced above, a dedicated Demonstration Program landing page.

Virtual and In-Person Marketing

One learning from prior NPA efforts in other regions is that deep engagement is needed. Given the complexity of the Demonstration Program offering and the need to maximize engagement with potential participants, a third-party contractor will conduct in-person outreach and engagement via door-to-door canvassing, live webinars, and community information sessions. This outreach will serve to validate the opportunity for potential participants and offer them an opportunity to ask detailed questions. Local community events, including events hosted in the homes of "Heat Pump Champions" (which are described in Section 2.3.2 below) will provide opportunities for potential participants to directly experience an all-electric home and to interact with electric appliances with which they may be unfamiliar, such as induction stoves. Although the in-person outreach will be arranged and conducted by the Lead Vendor selected by the Companies, all webinars and community events will involve participation by representatives of the Companies. A call to action will be stated at the conclusion of all virtual and in-person events, encouraging customers to schedule Home Energy Assessments. Additionally, all attendees will be provided with the Customer Participant Agreement for review.

In order to better understand the market landscape of providers who can conduct the customer and community outreach and engagement necessary to maximize the success of the Demonstration Program and gain an indicative sense of the potential cost of providing those services, the Companies issued a request for information ("RFI") in late September 2024 to thirteen companies. Of those thirteen, six responded. The Companies plan to issue a competitive solicitation for these services upon Demonstration Program approval.

Winthrop Community First Partnership

The town of Winthrop, one of the two selected for this Demonstration Program, is currently a Community First Partner. The Community First Partnership "leverages the local knowledge and trusted relationships of municipalities and community-based organizations to increase participation in Mass Save energy efficiency programs," and "drives participation among the priority customer groups of renters, landlords, low- and moderate-income households, customers who speak languages other than English, and small businesses in participating communities."[21] Winthrop participates in collaboration with the nearby towns of Revere and Chelsea, is currently only enrolled through 2024, and has applied for the future term. If the town of Winthrop participates as a Community First Partner for the next program period (namely 2025-2027), the

[21] Community First Partnership website, https://www.masssave.com/en/community/community-partnership

Demonstration Program would seek to collaborate with their Energy Advocate on outreach methods and events to further promote the Demonstration Program's offerings to the selected customers.

Heat Pump Champions

To generate interest and enthusiasm among eligible customers, the Companies aim to select up to five Heat Pump Champions for the Demonstration Program. The Heat Pump Champions would be eligible customers that express a strong desire to participate and agree, as a condition of participation, to share their experiences with their neighbors and others in the community. Heat Pump Champions will benefit by receiving the Demonstration Program offering, including pre-weatherization barriers, pre-electrification barriers, weatherization, and installation of all-electric appliances as soon as practical, regardless of whether their neighbors on the segment also agree to disconnect from the gas system. In exchange, the Companies will not only gain insight into ways to improve the customer experience and optimize marketing to other eligible customers but will also gain a valuable word of mouth tool that will enhance the Demonstration Program's other marketing and outreach efforts.

Customers interested in being Heat Pump Champions must agree to complete the Customer Participant Agreement and agree to the Heat Pump Champion terms and conditions. The Companies will prioritize the selection of customers as Heat Pump Champions based on the following criteria: (a) those that are not located on the same segment (so as to increase the number of potential participants that may come into contact with Heat Pump Champions and increase the ease for potential participants of visiting their home), (b) those that are spread across Leominster and Winthrop, and (c) demonstrated interest.

In response to stakeholder feedback, the Companies will work with local community organizations to determine if existing customers in Leominster and Winthrop with full electric heat pumps and all-electric appliances are willing and able to serve as Heat Pump Champions.

2.3.4 Demonstration Program Implementation

Expression of Interest and Home Energy Assessments

Customers who express interest in the Demonstration Program will be provided a customer-friendly, plain language summary[22] of the Demonstration Program with a brief timeline of the process and be asked to sign a consent for limited customer-specific data-sharing between Boston Gas and Mass. Electric, and the contractors hired by the Companies for implementation of the Demonstration Program. This form will prompt interested participants to be contacted to schedule and complete a no-cost Mass Save Home Energy Assessment through the Mass. Electric's Residential Turkey Services or Income Eligible Mass Save offers. Not only are Home Energy Assessments required to receive the incentives and rebates offered through Mass Save, but they will also provide potential participants and the Companies with valuable information regarding home condition and existing mechanical systems, potential options for conversion, and

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[22] The plain language summary has been translated into Spanish, Portuguese, and Haitian Creole based on input from local town officials and can be made available in other languages upon request.

will enable the appropriate sizing and design of the heat pump systems for those who elect to participate in the program.[23]

Once Home Energy Assessments have been completed, the Lead Vendor will review the results of those assessments with customers and describe the scope of work for whole home electrification. This touchpoint provides the contractor an opportunity to review with the customer what they are eligible to receive at no cost and to invite the customer to sign the Customer Participation Agreement if they wish to commit to participation.

As potential Demonstration Program participants move through the customer journey from expressing interest to completing Home Energy Assessments to signing the Customer Participation Agreement, marketing and outreach efforts will focus on those segments that have the most demonstrated interest. Experience with NPAs in other jurisdictions suggests that it is likely that initial interest will be scattered across segments. Therefore, as customers demonstrate interest, outreach will adapt to engage or reengage with neighbors of interested customers in an effort to achieve full participation.

[23] Note that some customers may express interest in a Home Energy Assessment without desiring to move forward with full electrification of their home and participation in the Demonstration Program. In those cases, the Companies will ensure those customers are able to schedule and complete a Home Energy Assessment, as they would be in the absence in the Demonstration Program. In other words, the completion of a Home Energy Assessment will not depend upon a customer's agreement to participate in the Demonstration Program. For LPP segments that cannot move forward with decommissioning as part of the program (e.g., because fewer than 100% of customers on that segment elect to participate), customers on those segments will still be eligible for a Home Energy Assessment and Mass Save® incentives, as they otherwise would, and the Companies and its vendors will still ensure that those customers are aware of that fact.

Customer Participation Agreement

When customers are ready to commit to participate, they will enter into an agreement such as the illustrative Customer Participation Agreement with the Companies. That Customer Participation Agreement will require customers to acknowledge and agree that participation requires disconnecting from the gas system as of a certain date or upon disconnection of all gas appliances in the home and outline all terms and conditions associated with participating in the Demonstration Program, including property access approvals and landlord/tenant agreements.

If 100% of customers on a given segment, or a subset of customer(s) who are contiguously located at the end of the segment such that it can be decommissioned, sign the Customer Participation Agreement, the customers will be notified that the Companies will be moving forward with Stage II and the installation of electrification measures[24].

Outreach and education to segments is expected to last approximately 12 months, though may go longer where continued outreach focused on segments with interest may result in segment decommissioning. If the Companies are unable to achieve 100% customer participation on any of the 14 targeted segments (or any segments that might be added or substituted during the Demonstration Program), the Demonstration Program would conclude without retiring any segments of LPP. The Companies would then file a final evaluation report documenting its efforts

[24] Separate from the Demonstration Program, interested customers can still move forward with the energy efficiency and electrification improvements recommended during completed Home Energy Assessments at existing Mass Save incentive levels. The Companies will note those upgrades for future efforts along those gas line segments.

and any key learnings.[25]

Conversion

Once customers are notified, they will move forward with conversion, either as part of an LPP segment that reaches sufficient participation or as one of the "Heat Pump Champions," and they will move into the conversion phase. This stage will involve the remediation of any pre-weatherization and/or pre-electrification barriers, weatherization and insulation, installation of the air-source heat pump, smart electric panel and smart thermostat, replacement of all gas-fired appliances with electric alternatives, including any necessary wiring and circuit upgrades (e.g., 240V circuit to support an induction stove), removal of gas-fired equipment, and disconnection from the gas system.

For any segments that will be going forward or for any customers who are selected to be Heat Pump Champions, conversion will be managed by the same vendor that completed the Home Energy Assessment and system design, either the Lead Vendor[26] or the local Community Action Agency[27]. As part of the turnkey process, the Companies plan for all customer conversion work to be managed by a single vendor to ensure that the work is efficiently coordinated for the customer.

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[25] Heat Pump Champions will still move forward regardless of segment electrification as they are part of the effort to encourage customers to participate.

[26] "The Lead Vendor conducts home energy assessments for customers, manages contractor agreements, and implements all other aspects of the program." Mass Save®, (n.d.), *Home Energy Service Providers,* Mass Save® | Partners | Home Energy Services Participating Contractors

[27] A Community Action Agency serves disadvantaged individuals and families by minimizing the effects of poverty, promoting economic security, and advocating for social change. They provide an appliance management program, fuel assistance (LIHEAP), heating system repair and Replacement, utility bill discounts, weatherization, and more.

Since Mass. Electric already offers many of these weatherization and electric equipment upgrades through its sponsorship of Mass Save, and all work that falls within the purview of Mass Save must be completed by the contractor for the Mass Save program, the Companies will be utilizing CLEAResult or the local Community Action Agency as subcontracts to Action, Inc, the current Lead Vendors in these geographic areas, for the customer Home Energy Assessments and conversion work.

When segments reach full participation, the customer electric system upgrades will be reevaluated based on the confirmed number of participants, heat pump sizes, and other appliances to be installed. Electric network upgrades, likely transformer upgrades (see Section 4), will then go to design and construction. While some customer work can begin ahead of network upgrades, such as addressing pre-weatherization and pre-electrification barriers and weatherization, transformer upgrades should be completed before heat pumps are installed.[28]

Post Conversion

Once a home is fully electrified, it will enter Stage III which includes program evaluation, support, and maintenance. The third-party evaluation contractor will study participant satisfaction, participant total energy costs (pre- and post-electrification, and inclusive and exclusive of proposed bill credits), estimated GHG emissions reductions, and the impacts on monthly electric consumption and peak demand. To ensure success for the customer, the Companies will use the

[28] It is possible that the timing of customer and network upgrades could depend on the season, as long as transformer upgrades are installed ahead of the heating season.

same Lead Vendor that completed the whole home electric conversions to support the maintenance and functioning of the ASHP for two years post conversion. All other appliances are covered by standard manufacturer's warranties.

2.4 Additional Details

2.4.1 Cost to Customers

As mentioned above, the Demonstration Program will ensure that participating customers bear no upfront costs. This upfront cost barrier may be the customer portion of total cost (i.e., the net of other incentives received) or the cost burden of carrying the purchase price for a given appliance until the incentives and/or tax credits are received. To avoid this problem, as described in the Equipment Selection section below, the customers will select the equipment that they wish to purchase, and the actual purchase will be made by the Lead Vendor hired by the Companies. The traditional measures that are covered by Mass Save will be tracked in the Companies' tracking system, and then the Lead Vendor will provide pricing to the Companies, which will be allocated between energy efficiency program incentives and the Demonstration Program.

2.4.2 Eligibility of Non-Active Gas Accounts and Non-Gas Customers

Several homes on 4 of the 14 LPP segments being targeted for the Demonstration Program are either not connected to the natural gas system or do not have an active gas account. Since allowing those homes to participate would increase program costs without helping to achieve the program goal of decommissioning segments of LPP, these homes will not have the option to participate in the Demonstration Program. Instead, the Companies will direct them to the Mass Save incentives for which they are eligible.

Homes on segments that are due to be decommissioned and who wish to request a connection to the gas system, whether resuming service or initiating a new service, will not be able to connect to the gas system during the Demonstration Program's time period of customer engagement. If the Companies have knowledge of a specific account where gas service was ended due to a planned renovation, they will attempt to contact the account owner to determine the status of their account and if they are planning to reconnect to the gas system; decisions about how to proceed in those instances will be made on a case-by-case basis.

2.4.3 Equipment Selection/System Design

The Home Energy Assessment results will be used to inform potential participants and the Companies of the specific gas-fired equipment that must be replaced at each customer's premises to move forward with participation. Potential participants will be offered a small, curated catalog with electric appliance models to replace each gas-fired appliance; the models offered will be (a) highly efficient and (b) already eligible for Mass Save incentives. If a participant wishes to purchase a different model than the default options, they will be free to do so (a) if the appliance is in the Mass Save Qualified Product List, and (b) the participant pays the incremental cost of the model above the highest cost of the models offered for that category.

All installed heat pumps will be high efficiency cold-climate models ("CCHPs") chosen from the Mass Save Heat Pump Qualified Product List.[29] Heat pump systems will be sized to ensure proper heating capacity for each home (post-weatherization). Supplemental electric resistance heating and/or backup gas generators will not be offered as part of the Demonstration Program.

2.4.4 Evaluation, Measurement, and Verification

To obtain data and learnings useful to future electrification efforts, the Companies will track metrics associated with the Demonstration Program, such as customer interest and response rates, effective marketing strategies, costs of home electrification, participant experience and satisfaction, changes in annual and peak energy consumption, and bill impacts. The Companies will file an annual evaluation report on the progress of the Program, which will include key learnings and costs to-date and will file a final evaluation report at the conclusion of the Program, either two years after segment electrification or within five years after the start of the Program. The evaluation of the Demonstration Program will be conducted by a third-party evaluator and an evaluation report will be filed with the annual cost recovery filing for the Demonstration Program.

During Stage I, the evaluation will include customer response rates, customer interest, drivers for and barriers to participation, learnings on effective engagement strategies, and participation levels. The evaluation will also include learnings from how the Heat Pump

[29] Heat Pump Qualified Product List (HPQPL) (masssave.com).

Champions can best be utilized to drive interest and change the perception of other neighboring customers or their level of participation, and how community groups and municipal and elected officials can help support interest and participation. These learnings will inform marketing for future targeted electrification initiatives and methods of customer communication and outreach for the NPA framework in development.

Stage II will assess the costs and timeline of whole-home electrification and gas decommissioning, including whole-home electrification for participating customers (including pre-weatherization and pre-electrification barriers and weatherization, as necessary) and disconnecting and removing customers' gas appliances, electric network upgrades, and decommissioning and retiring segments of gas pipe and customer services. The evaluation will also include an assessment of variables that cause a disproportionate share of expense and/or customer disruption (e.g. pre-weatherization barriers), and ways of managing those in the future. These learnings will inform cost estimates and timelines for electrification of segments of customers for future NPA efforts.

During Stage III, for participating customers, the evaluation will include participant satisfaction, participant total energy costs pre- and post-electrification (inclusive and exclusive of proposed bill credits), estimated GHG emissions reduction, the impacts on monthly electric consumption and peak demand and the peak demand coincidence among neighboring all-electric homes. The smart panels included in the customer offering will provide valuable empirical data on peak demand and load profiles of all-electric homes, which can be leveraged for future forecasting and planning, to inform NPA assumptions, and to provide insights on opportunities for future winter load flexibility. Data on pre- and post-electrification energy use and customer bill impacts will also be used to inform the assumptions used in future NPA assessments.

A description of key metrics is included in Figure 2 below. The final evaluation report will also include any other learnings on process which will help advance and scale future gas decommissioning projects and the development of an NPA framework.

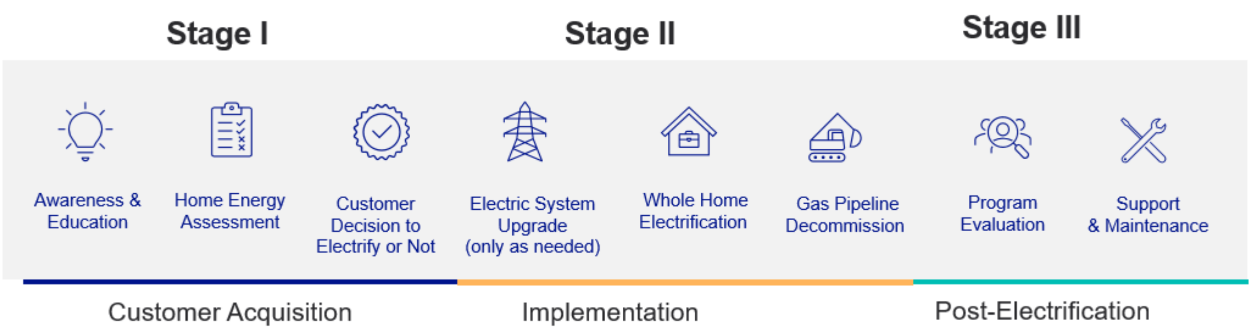
Figure 5. Evaluation, Measurement, and Verification Metrics and Descriptions

Metric	**Description**
Participant satisfaction and deep dive survey	Measure of post-conversion participant satisfaction with the new systems and appliances, as well as non-participant barriers to program participation
Average monthly electricity consumption	Analysis of pre- and post-installation monthly electricity usage over a minimum of two heating and cooling seasons
Average monthly electricity costs for participants	Analysis of participant electric bills over a minimum of two heating and cooling seasons (inclusive and exclusive of bill credits)
Peak demand and peak coincidence	Analysis of actual post-installation peak electricity demand relative to design estimates, including peak-coincidence among neighboring households
Disaggregated appliance-level electricity consumption and peak demand	In instances where smart panels are installed, analysis of each electric appliance's monthly consumption, hourly load profile, and peak demand
Estimated greenhouse gas (GHG) emissions reductions	Greenhouse gas emissions reductions associated with whole-home electrification and LPP segment decommissioning

2.5 Demonstration Program Timeline

The Companies have developed the following preliminary timeline for the Demonstration Program.

Figure 6. High Level Program Stages



Program stage	Estimated amount of time to complete
Awareness and education	Approximately 12 months
Home energy assessments	
Decision to electrify or not	
Electric system upgrades (only as needed)	Varies by segment
Whole home electrification	Varies by home (estimated 2-6 months but will be dependent upon many factors, particularly the amount of pre-weatherization and pre-electrification work required)
Gas pipeline segment decommission	Varies by segment
Program evaluation	16 months
Support and maintenance	2 years post electrification for ASHP. Other appliances will be covered by warranties

3. Location Identification

Beginning in the summer of 2022, the Companies began collaborating to identify municipalities with segments of LPP in the Companies' overlapping gas and electric service territories that could be good candidates for targeted electrification. The analysis demonstrated that electric system impacts of heat electrification are location dependent influenced by multiple factors, including the existing size and capacity of electric infrastructure and the assumption of peak electric heat demand. These findings helped the Companies identify criteria for a targeted demonstration program.

3.1 Criteria for Selecting Municipalities

The Companies first identified municipalities that fulfilled the following criteria:

1. Municipalities with a high inventory of LPP, and in which a relatively high amount of that LPP has a low LPP risk score and, consequently does not need to be replaced in the next three to five years (thereby allowing sufficient time for customer outreach and Demonstration Program implementation.
2. Municipalities which would not require extensive electric network capacity upgrades to support incremental loads due to electrification, and
3. Municipalities with diverse electric network conditions including varying densities of distributed energy resources penetration.

This analysis resulted in the selection of Winthrop and Leominster.

3.2 Criteria for Selecting Segments within those Municipalities

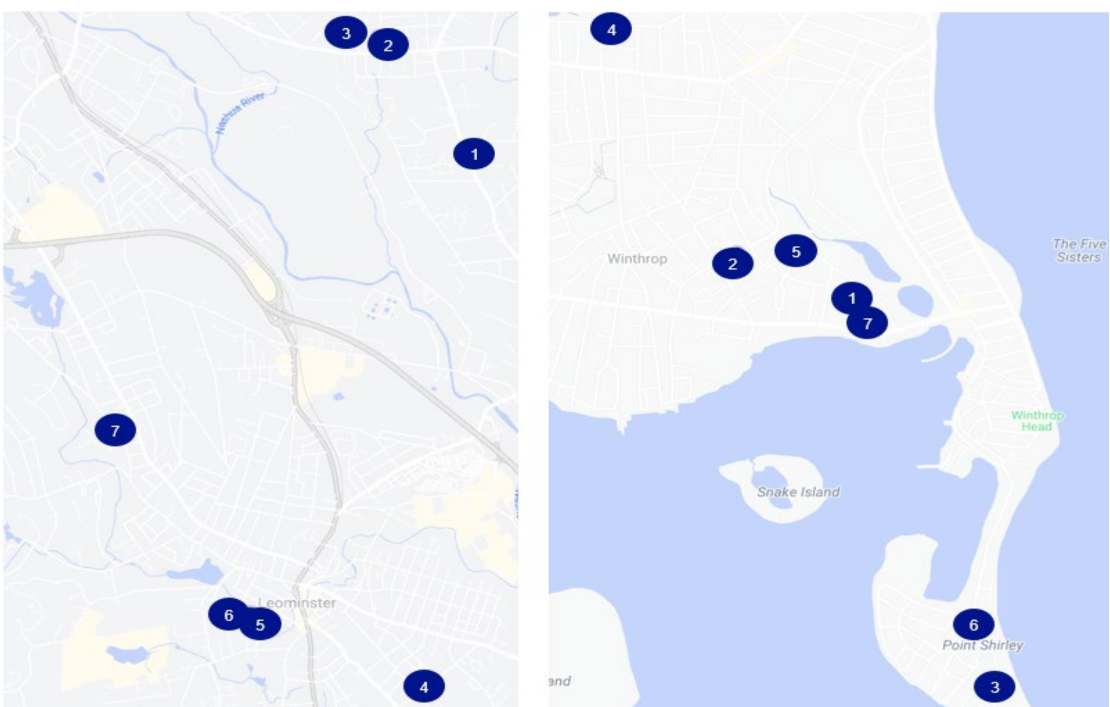
The Companies further refined targeted electrification candidate areas by identifying distribution feeders with spare capacity where upgrades would be unlikely for a small amount of added load. The Companies then identified single-feed LPP segments that did not impact the continuity of the gas system. This process revealed an initial list of prioritized segments of LPP within Leominster and Winthrop. Within those municipalities, ideal project segments were identified based on the following criteria:

1. Segments of LPP which are not currently scheduled for replacement in the next 3 to 5 years;
2. LPP segments that would have a minimal hydraulic impact on the gas network if retired;
3. Segments with the fewest number of customers, considering the challenges of coordinated, voluntary adoption; and
4. LPP segments located in areas with available electric capacity and/or areas where the Companies anticipate minimal electric distribution system upgrades if all customers electrify gas end uses.

As described more fully in Section 5, earlier this year representatives of the Companies met with Winthrop's town officials who suggested that segments in flood prone zones should be included since customers prone to flooded basements where their gas heating equipment is typically located would be more likely to participate. This input led to the addition of 6 in or near flood prone zones. Based on the analysis completed by the Companies' gas and electric engineering teams, 14 segments across Leominster and Winthrop, each with 4-13 gas customers, have been identified as viable locations for the Demonstration Program, eight of which are in Environmental Justice Communities. The fact that a majority of the locations were in Environmental Justice communities was also a deciding factor to move forward with these segments from a desktop analysis to a customer-facing Demonstration Program.

3.3 Segment Overview

Figure 7. Segment Location – Leominster (left) & Winthrop (right)



An overview of the proposed segments is shown in the table below.

Table 3. Segment Characteristics

Segment	Town	LPP Gas Main Length (ft)	Estimated Avoided LPP Replacement Cost	Gas Meter Count	EJC	Flood Prone Zone	Customer Density (Customers/ mile)
1	Leominster	700	$251,841	4	Y	N	30
2	Leominster	1090	$436,527	8	Y	N	39
3	Leominster	680	$284,928	7	Y	N	54
4	Leominster	675	$299,313	10	Y	N	70
5	Leominster	250	$155,540	4	Y	Y	63
6	Leominster	615	$382,628	12	Y	Close[30]	69
7	Leominster	1095	$681,264	7	Y	Close	34
8	Winthrop	190	$167,886	4	N	N	167
9	Winthrop	455	$290,748	10	N	N	93
10	Winthrop	500	$414,343	12	N	N	74
11	Winthrop	285	$220,770	10	Y	N	185
12	Winthrop	430	$267,528	10	N	Y	98
13	Winthrop	445	$316,205	13	N	Y	131
14	Winthrop	115	$130,653	7	N	Y	321
Total		**7525**	**$4,300,174**	**118**			

During the Demonstration Program, some segments may be removed from the potential electrification pool due to several reasons, such as a change in the LPP risk score or a lack of customer engagement. If so, the Companies may choose to replace them with an alternate LPP segment or segments. New segments will be prioritized based on the criteria described above. The

[30] Located in close proximity to a flood prone zone (within ~150 feet).

Companies will report on segments that have been added or removed in the annual evaluation report.

4. Electric Grid Impacts

As described in Section 3 – Location Identification, relative electric network capacity to support electrification was a criterion in selecting the locations for the Demonstration Program. After selecting locations and identifying customers on each segment, the Companies conducted an analysis of the electric grid impacts associated with customer electrification on those segments.

4.1 Customer Analysis Data Assumptions

Under the Department's affiliate standards of conduct, the Companies are not permitted to share proprietary customer information between affiliates, absent prior written authorization from the relevant customers. As a result, the Companies developed a methodology to estimate the electric system impacts associated with electrification of the relevant gas segments using appropriate workarounds to ensure that sensitive customer information would not be shared between affiliate Companies. For instance, rather than developing customized electric loading assumptions for each individual customer based on converting individualized historical gas consumption data to a resulting electric load impact, the Companies developed and used assumptions for the peak electric demand impacts of whole home electrification for an average residential home in the Mass. Electric service territory. As discussed below, using simplified assumptions is sufficient for a small-scale residential-only demonstration project, but would not be scalable for the NPA assessment and implementation envisioned in D.P.U. 20-80-B.[31]

4.2 Customer Electrification Load Impact Assumptions

To assess the impact of full home electrification on the electric grid, the Companies estimated the incremental peak electric load for an average residential home in Massachusetts using hourly load profiles for air-source heat pumps, heat pump water heaters, electric stoves, and electric clothes dryers. The air-source heat pump load profile is derived from studying the simulated heating behavior of a sample of residential buildings in the National Grid electric service territory of Massachusetts, and adjusting those to account for peak weather conditions, conventional growth in heating requirements, improvements to building envelopes, and heat-pump performance assumptions. The ResStock tool developed by National Renewable Energy Laboratory (NREL) and heat pump heating efficiency study from the Executive Office of Energy and Environment Affairs (EEA) and the MA Department of Energy Resources (DOER) were used for the study, consistent with the data source used for Mass. Electric's electric peak forecast. The assumption for this Demonstration Program is based on the non-coincident peak, given that local

[31] In parallel, the Companies, along with the other gas and electric distribution companies, filed a joint motion for exemption and request for authorization to share proprietary customer information for D.P.U. 20-80-B compliance, which would allow them to perform a full analysis of customer information using data from both the gas and electric perspectives by sharing certain proprietary customer information for IEP purposes. This motion is currently pending the Department's decision.

distribution infrastructure must meet the local peak. The Companies identified the peak hour of ASHP demand and used the 24-hour load profile associated with that day.

The Massachusetts Residential Baseline Study[32] was used to derive load profiles for heat pump water heaters, electric stoves, and electric clothes dryers. For each appliance type, the 24-hour load profile associated with the maximum demand on a winter peak day was used. The 24-hour load profiles for a winter peak day were then combined with the ASHP 24-hour load profile to determine the maximum peak load, as shown below. This methodology was then repeated for a summer peak day.

The Companies also performed an electric vehicle ("EV") sensitivity analysis to assess the potential additional load impact from EV adoption that would arise from the residential home charging of light-duty electric vehicles. The purpose of the sensitivity analysis was to consider how electric upgrades and solutions might differ when building for the future and accommodating the load impacts of transportation electrification as well as home electrification. The light-duty EV charging load profile is based on the ISO-NE EV charging load shape from their 2019 ChargePoint study[33]. To get the home charging profile, the aggregated profile from the study was broken out

[32] https://ma-eeac.org/studies/residential-program-studies/. 2023 Residential Baseline Study Appendices for Water Heating, Kitchen and Laundry Electric Load Shapes.
[33] https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf

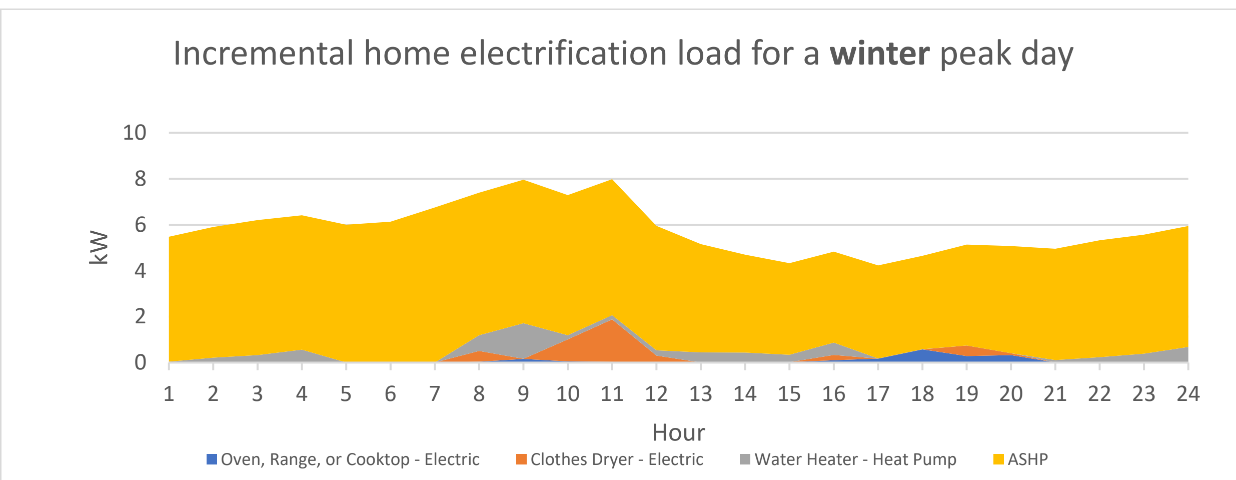
using locational energy shares from NREL's EVI-Pro Lite tool which provides shares for home, work, and public charging activity.[34]

As shown below, the assumptions for incremental electric peak load (kW) for a representative residential customer in Massachusetts are as follows:

Table 4. Assumptions Used for Incremental Electric Peak Load

Scenario	Incremental Peak Load Assumption per Customer (kW)
Winter Peak – Home Electrification	8 kW
Winter Peak – Home Electrification + EV Sensitivity	9.5 kW
Summer Peak – Home Electrification	2.6 kW
Summer Peak – Home Electrification + EV Sensitivity	5.3 kW

Figure 8. Incremental Home Electrification Load for a Winter Peak Day



[34] https://www.nrel.gov/transportation/evi-pro.html

Figure 9. Incremental Home Electrification Load for a Winter Peak Day with EV Sensitivity

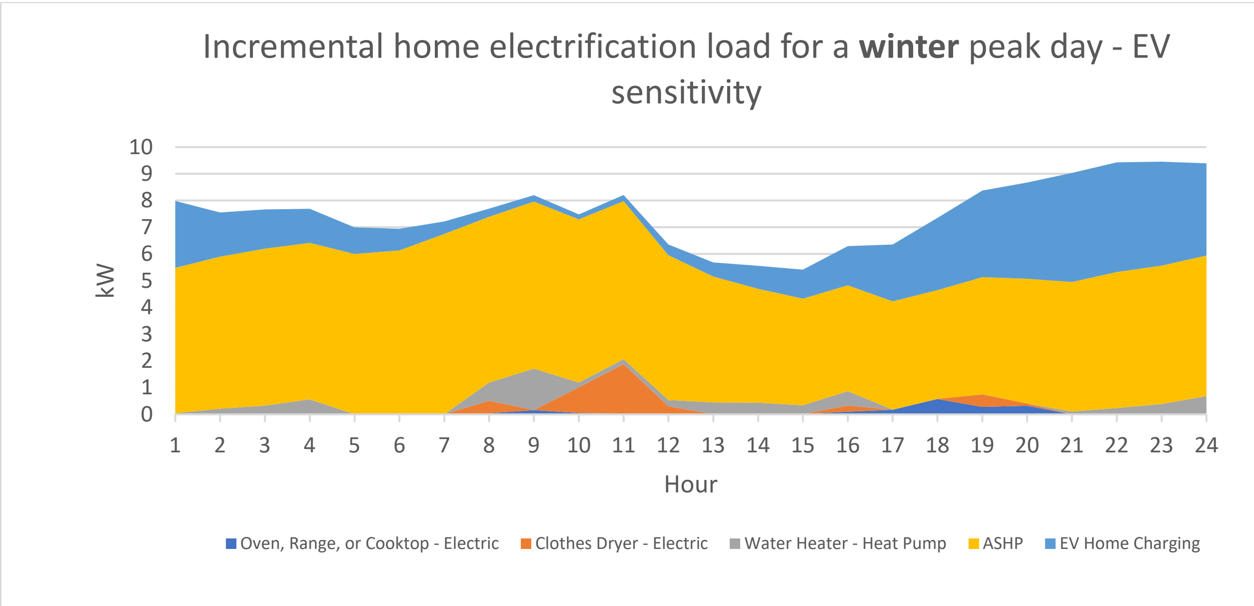


Figure 10. Incremental Home Electrification Load for a Summer Peak Day

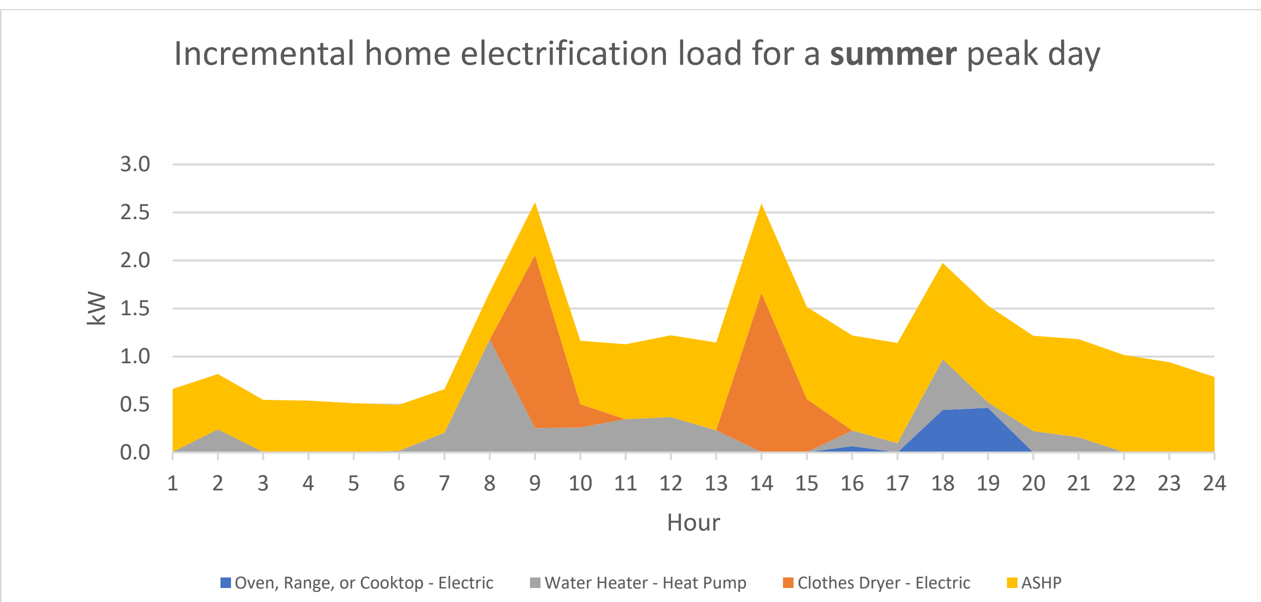
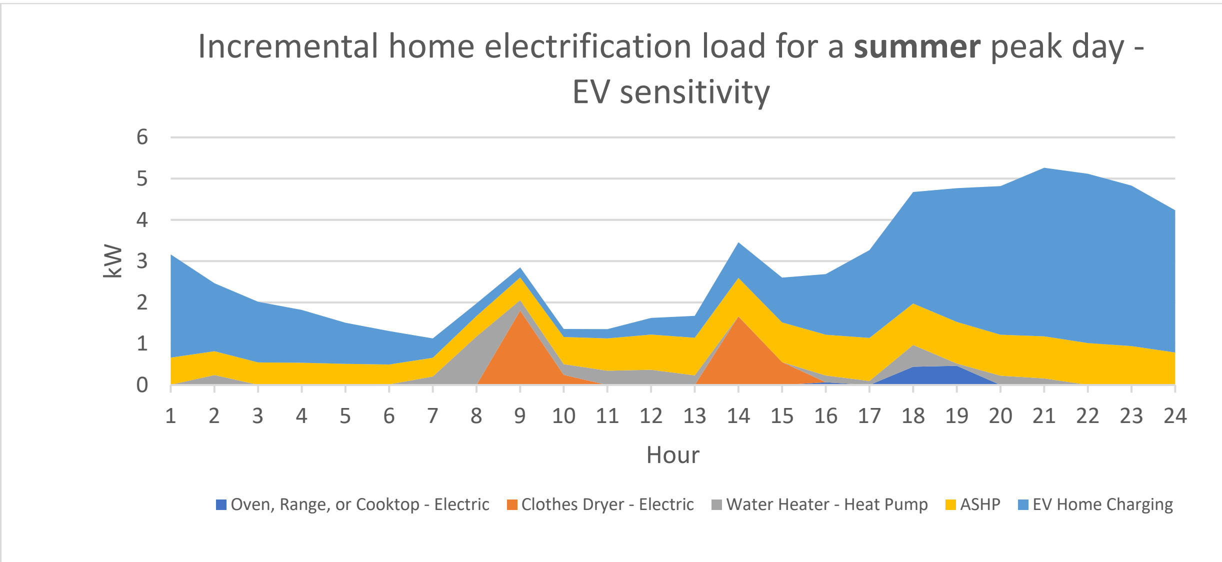


Figure 11. Incremental Home Electrification Load for a Summer Peak Day w/EV Sensitivity



4.3 Electric Analysis Methodology

Mass. Electric performed a detailed engineering analysis to identify loading and voltage issues caused by electrification of customers on the identified segments and to develop solutions to address these issues. Both a winter peak and summer peak analysis were performed to ensure all adverse impacts on the system were addressed in both seasons. Mass. Electric used projected winter 2024/2025 peak loads and projected summer 2024 loads as the basis for the analysis. A sensitivity analysis was also performed for projected summer 2025 peak loads, and no additional issues or upgrades were identified beyond the 2024 summer case. The team utilized the projected peak loads for the summer and winter cases and added the total electrification load impacts (explained in section 4.2 above) to each electrification customer. In total, 4 scenarios were analyzed:

- Winter 2024/2025 projected peak loads without EVs: Customer Base load + 8kw
- Winter 2024/2025 projected peak loads with EVs: Customer Base load + 9.5kw
- Summer 2024 projected peak loads without EVs: Customer Base load + 2.6kw
- Summer 2024 projected peak loads with EVs: Customer Base load + 5.3kw

4.4 Results

The winter 2024/2025 case resulted in more significant impacts on the distribution system so results explained in this section and in the table below are for the winter scenario. All solutions for the winter analysis also solve all issues in the summer cases.

4.4.1 Analysis with EV Sensitivity

The engineering analysis identified numerous issues on the secondary distribution system in the winter 2024/2025 and summer 2024 cases but no issues on the primary distribution system. The secondary distribution system refers to pole top distribution transformers and the low voltage secondary lines they supply while the primary distribution system refers to upgrades on the high voltage lines supplying pole top distribution transformers. In the winter electrification analysis scenario including EV impacts (9.5kW of additional load per customer), 19 distribution transformers are loaded in excess of their ratings. To mitigate these overloads and accommodate the electrification load additions, 34 new distribution transformers are recommended for installation along with associated secondary upgrades. The total cost estimate for the electric grid investments required for full electrification of the identified customers across all segments and to support future EV adoption is $1,363,706. All recommended upgrades solve all issues in both summer and winter seasons.

The anticipated electric network upgrades for whole home electrification including EV impacts are shown in the table below.

Table 5. Anticipated Electric Network Upgrades per Segment (Including EV Impacts)

Segment	Substation	Feeder	Customers	Transformers Needed	CAPEX	OPEX	Cost of Removal	Total Cost Estimate
1	Prospect St	05_01_219W2	4	1	$34,908	$770	$4,431	$40,109
2	Prospect St	05_01_219W2	8	3	$104,724	$2,310	$13,293	$120,327
3	Prospect St	05_01_219W2	7	2	$69,816	$1,540	$8,862	$80,218
4	Litchfield	05_01_207W4	10	3	$104,724	$2,310	$13,293	$120,327
5	Litchfield	05_01_207W2	4	1	$34,908	$770	$4,431	$40,109
6	Litchfield	05_01_207W2	12	4	$139,632	$3,080	$17,724	$160,436
7	Litchfield	05_01_207W2	7	2	$69,816	$1,540	$8,862	$80,218
8	Metcalf St	05_12_96W1	4	1	$34,908	$770	$4,431	$40,109
9	Metcalf St	05_12_96W1	10	3	$104,724	$2,310	$13,293	$120,327
10	Metcalf St	05_12_96W1	12	3	$104,724	$2,310	$13,293	$120,327
11	Winthrop	05_12_22J7	10	3	$104,724	$2,310	$13,293	$120,327
12	Metcalf St	05_12_96W1	10	3	$104,724	$2,310	$13,293	$120,327
13	Metcalf St	05_12_96W1	13	3	$104,724	$2,310	$13,293	$120,327
14	Metcalf St	05_12_96W1	7	2	$69,816	$1,540	$8,862	$80,218
Total			**118**	**34**	**$1,186,872**	**$26,180**	**$150,654**	**$1,363,706**

4.4.2 Analysis without EV Sensitivity

Mass. Electric also performed a sensitivity analysis for electrification of the identified customers excluding electric vehicle impacts. Without EV impacts, 10 fewer distribution transformers would need to be installed. The total cost estimate for the electric grid investments required for full electrification of the identified customers across all segments excluding EV impacts is approximately 29% lower than with EV impacts. Excluding EV impacts in the analysis is not aligned with the Mass. Electric's forecasting and planning processes which are designed to meet the Commonwealth's decarbonization goals established in the 2050 Clean Energy and Climate Plan (2050 CECP). Therefore, Mass. Electric will design to the scenario including EVs to proactively accommodate electric vehicles, in addition to the home electrification encouraged by this demonstration.

4.5 Managing Peak Demand

As described in Section 1.3, the Companies seek to develop learnings regarding internal capabilities, processes and assumptions needed to successfully deliver future NPAs and targeted electrification at scale, including electric grid peak impact analysis. This Demonstration Program will provide important learnings on how whole home electrification of multiple customers on the same street impacts local peak electric demand, including empirical data on the degree of peak coincidence among neighbors, especially during times of extreme hot or cold weather. For the purposes of this Demonstration Program, the Companies have included estimated costs for all electric grid upgrades needed to enable customer electrification based on empirical load profiles (see section 4.2) and do not explicitly assume peak load shifting.

However, the Companies plan to engage in several approaches with participating customers to gain learnings related to peak demand management that can be leveraged for future NPAs, especially in the medium to long term when the Companies expect much of its electric grid to become winter peaking, driven in large part by heat electrification.

First, the Companies will educate customers with tips on how to efficiently utilize their new equipment, and how to participate in peak demand management programs, such as ConnectedSolutions (demand response). Heat pumps become significantly less efficient if they are run at full capacity, which can often result in the supplemental resistance heater element activating. Unlike gas boilers, setting the temperature back at night and then ramping up before the anticipated wake up time could result in the heat pump running less efficiently. Instead, heat pump customers should set the temperature and leave it or utilize smart controls to reduce the rate of change in the temperature of a space (e.g., bring a room up to temperature over a period of time rather than waiting until shortly before occupancy).

Second, as described in in Section 2.2.2, the Companies will include a smart panel as part of the Demonstration Program offering to any customer that participates.[35] Smart panels will be offered to customers to provide greater visibility and control of their circuit-level assets (e.g., heat pumps) and real-time energy usage. They will also provide valuable data points on heat pump peak

[35] Customers will be able to opt out if they do not want a smart panel.

demand impacts and enable the Companies to test how impactful smart panels can be as a peak demand management tool without impacting customer comfort. At agreed upon times, participating customers will receive temporary, artificial virtual service limit signals to their smart panels to test how their smart panels can automate pausing or shifting loads in line with customer preferences, to remain within those limits with minimal or no customer inconvenience.

Third, customers in each segment are scheduled to receive new AMI meters by 2027 as part of Mass. Electric's current AMI deployment plan that is currently under way. Deployment of smart meters will enable more advanced, time-varying rate design that would create price signals for residential customers to manage peak demand to help manage their bills.

Finally, the Companies seek to leverage the successful approaches utilities have used to engage customers in technology-driven demonstration programs. Leveraging best practices will help the Companies effectively engage with customers, gather feedback, and catalyze adoption of innovative technologies. [36] For this Demonstration Program, direct engagement with participating customers will enable the Companies to explore additional innovative electrification-related technologies that can further support peak demand management (e.g., thermal storage) on a case-by-case basis with interested customers who may be driven to participate in the Demonstration Program in part due to the opportunity to be early adopting innovators.

[36] https://portlandgeneral.com/about/who-we-are/innovative-energy/smart-grid-test-bed

5. Stakeholder Engagement

Pursuant to the Order Establishing Tiering and Outreach Policy, D.P.U. 21-50-A, Appendix A: Tiering and Outreach Policy (2024), the Demonstration Program is designated as a Tier 1 proceeding because it will have a significant geographic-specific impact on an Environmental Justice population in Leominster and Winthrop that is not shared by the rest of the service territory. In compliance with these requirements, the Companies engaged with municipal and community leaders to receive feedback that was incorporated into the Demonstration Program, developed a plain language summary, determined the appropriate languages for translation and distributed it. Exhibit TEP-3 contains additional details on the Companies outreach efforts. The Companies will continue to collaborate with stakeholders during the Demonstration Program as more fully discussed in Section 2.3.3.

6. Demonstration Program Costs

The Demonstration Program budget includes the costs of activities to conduct the Demonstration Program, including program administration, education and outreach, whole home electrification, participant bill credits, and EM&V. The final cost of the Demonstration Program will depend on the number of segments that reach full participation and are ultimately converted to electrification, and the cost of electrification for each customer, which depends on a number of factors, including the prevalence of pre-electrification barriers, level of weatherization needed, heat pump size, and appliances replaced.

6.1 Demonstration Program Costs

The estimated costs for the Targeted Electrification Demonstration Program, including program administration, education and outreach, whole home electrification, bill credits, and EM&V, if all 14 segments achieve full participation and deducting for Mass Save incentives, are approximately $11.3 million. The Demonstration Program expects to use existing Mass Save funding towards the cost of whole home electrification for participating customers, estimated at $2.6 million. A summary of Demonstration Program costs and the costs of Mass Save incentives provided to participating customers is shown in Table 6.

Table 6. Summary of Mass Save and Demonstration Program Costs

Cost Categories	Mass Save ($000s)	Demonstration Program ($000s)	Total ($000s)
Program Admin		$1,041	$1,041
Marketing & Outreach		$425	$425
Whole Home Electrification	$2,644	$8,897	$11,540
Opex associated with Electric Network Upgrades		$26	$26
Bill Credits		$602	$602
EM&V		$300	$300
Total	**$2,644**	**$11,291**	**$13,934**

An illustrative annual view of the Demonstration Program costs over six years is provided in Table 7.

Table 7. Illustrative Annual Demonstration Program Costs

Cost Categories ($000)	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Total

Program Admin	$200	$204	$208	$212	$216		$1,041
Marketing & Outreach	$325	$100					$425
Whole Home Electrification	$411	$8,485					$8,897
Opex associated with Electric Network Upgrades		$26					$26
Bill Credits	$5	$120	$120	$120	$120	$115	$602
EM&V		$33	$33	$33	$200		$300
Demonstration Program Total	**$941**	**$8,969**	**$362**	**$366**	**$537**	**$115**	**$11,291**

Key Assumptions:

- Whole Home Electrification represents the cost of addressing pre-weatherization and pre-electrification barriers, weatherization and switching all gas end uses to electric appliances, including air-source heat pumps, as described in section 2.2.1. This assumes that existing incentives offered through the Mass. Electric's sponsorship of Mass Save will be leveraged, estimated at $2.6 million, and that the remaining cost, estimated at $8.9 million, will be funded through the Demonstration Program. This assumes an average cost of $97,800 per participant to fully electrify $15,530 from Mass Save, $82,270 from the Demonstration Program for a market rate customer. Please see Table 8 below for a detailed cost breakdown).
- Five Heat Pump Champions electrify in Year 1 and the remaining customers electrify in Year 2.

- Program Administration includes one full-time equivalent over 5 years at a cost of $1 million (fully loaded).
- Marketing and outreach efforts will be focused in Year 1 of the Demonstration Program and may extend into Year 2 for a cost of $425 thousand.
- Bill credits assume an average credit of $85/month per participating customer over the 5-year span of the credit, beginning when electric appliances are installed.

The actual costs of participant incentives for electrification and bill credits are dependent on the number of segments that reach sufficient voluntary participation. Given the low NPA uptake seen in other jurisdictions, such as New York and California, it is highly unlikely that all or most segments will realize sufficient participation to move forward with targeted electrification and pay out incentives. Table 8 below provides a breakdown of the estimated customer incentive costs by segment.

If, for example, only Segment 1 reaches sufficient participation to move forward, the Demonstration Program Costs would be $2.1 million, including $1 million for Demonstration Program Administration, $425 thousand for marketing and outreach, $329 thousand for customer incentives, $20 thousand for bill credits, $1 thousand for operating expenses related to electric network upgrades, and $300 thousand for EM&V.

Table 8. Estimated Customer Incentive Cost By Segment

Table 8. Estimated Customer Incentive Costs by Segment

Segment	Customers	Low Income Customers[37]	Mass Save Incentives	Demonstration Program Incentives	Customer Electrification Total Cost
1	4	0	$62,120	$329,080	$391,200
2	8	1	$178,310	$604,090	$782,400
3	7	0	$108,710	$575,890	$684,600
4	10	0	$155,300	$822,700	$978,000
5	4	1	$116,190	$275,010	$391,200
6	12	0	$186,360	$987,240	$1,173,600
7	7	0	$108,710	$575,890	$684,600
8	4	0	$62,120	$329,080	$391,200
9	10	0	$155,300	$822,700	$978,000
10	12	1	$240,430	$933,170	$1,173,600
11	10	5	$425,650	$552,350	$978,000
12	10	2	$263,440	$714,560	$978,000
13	13	3	$364,100	$907,300	$1,271,400
14	7	2	$216,850	$467,750	$684,600
Total	**118**	**15**	**$2,643,590**	**$8,896,810**	**$11,540,400**

[37] Number of customers enrolled in the low-income discount rate.

6.2 Alignment with Mass Save Program Offerings

As mentioned above; to maximize participation, Demonstration Program participants will not incur any upfront costs for the measures and equipment installed. Behind the scenes to customers, funding for pre-weatherization, weatherization, and equipment to fully electrify homes will come from a combination of existing Mass Save Residential and Income Eligible incentives and Demonstration Program funding.

Mass Save, a collaborative of Massachusetts' electric and natural gas utilities and energy efficiency service providers, including Mass. Electric, already offers incentives and rebates for many of the measures and equipment to be installed as part of the Demonstration Program.[38] The Demonstration Program will coordinate with the Companies' Mass Save offers by leveraging existing Mass Save incentives for customers for pre-weatherization and pre-electrification barrier mitigation, home energy assessments, weatherization, heat pumps and other electric appliances. In cases where the cost of implementing energy efficiency measures and electrification for the Demonstration Program participants exceeds the amounts made available by Mass Save, the Demonstration Program will fund the difference between the cost of electrification and existing Mass Save incentives, such that participants will not be required to put down money or cover upfront costs. All home upgrades will be completed by existing Mass Save installers, which will be under contract to the Companies or one of their Lead Vendors.

[38] Residential Rebates & Incentives | Mass Save®

The following is a summary of the whole home electrification measures, estimated costs, and the sources of funding.

Table 9. Mass Save vs. Program Cost Overview

		Market Rate		Income Eligible	
Whole Home Electrification Cost	**Cost per Customer**	**Mass Save**	**Demonstration Program**	**Mass Save**	**Demonstration Program**
Pre-weatherization barriers (e.g., knob & tube, mold, asbestos)	$20,000	$250	$19,750	$20,000	$0
Weatherization (home insulation)	$5,000	$3,750	$1,250	$5,000	$0
ASHP	$32,000	$10,000	$22,000	$32,000	$0
Heat pump water heater	$6,000	$750	$5,250	$6,000	$0
Induction stove	$3,250	$500	$2,750	$3,000	$250
Heat pump dryer	$2,000	$50	$1,950	$2,000	$0
Smart thermostat	$400	$230	$170	$400	$0
Smart panel	$7,250		$7,250		$7,250
Electric fireplace	$1,300		$1,300		$1,300
Gas equipment removal & restoration	$5,000		$5,000		$5,000
Contingency	$14,400		$14,400		$14,400
Two-year services agreement	$1,200		$1,200		$1,200
Total Cost per Customer	$97,800	$15,530	$82,270	$69,600	$28,200

6.3 Reporting

The Companies propose to file an annual evaluation report that will provide updates on customer engagement, costs incurred, costs proposed for recovery, lessons learned, any risks that may have arisen in the time since filing, and EM&V metrics. Section 2.4.4. above provides detailed description of the evaluation report including status updates for all segments, along with an updated cost estimate, and plan for conversion. If insufficient customer interest exists on all segments such that none of them will be advancing, the Companies will file an evaluation report describing the actions taken, costs incurred, and lessons learned from the customer engagement portion of the Demonstration Program.

Attachments

ATTACHMENT A – Illustrative Customer Participation Agreement

(To be signed by potential Participating Customers and progressed if there is adequate participation in the Targeted Electrification Demonstration Program to retire the pipe segment serving these customers)

Massachusetts Electric Company and Boston Gas Company

Targeted Electrification Demonstration Program

Customer Participation Agreement Form

This form is to be filled out by customer(s) interested in participating in the Targeted Electrification Demonstration Program and returned to adrienne.agarwal@nationalgrid.com as soon as possible but no later than [insert date].

Congratulations on your decision to participate in the Targeted Electrification Demonstration Program and convert your natural gas heating equipment and other appliances to electric. Your new all-electric equipment and appliances will be designed to provide your home with year-round comfort, while reducing the emission of greenhouse gases and advancing Massachusetts' and National Grid's net zero emission goals. Please take a few minutes to review and acknowledge the following information regarding your project:

Customer Name:

____

Customer Premise Address:

____

Customer Mailing Address (if different from Premise address):

____

Customer Phone Number (with area code):

____

Customer National Grid Electric Account Number:

____

Customer National Grid Gas Account Number:

____

To participate in this Demonstration Program, customers must:

- Have a current account with Boston Gas Company ("Boston Gas") and Massachusetts Electric ("Mass. Electric") or in the case of a tenant-occupied building, the tenant(s) should have a current account with Boston Gas and/or Mass. Electric for the utility(ies) they are responsible for paying as part of their tenancy;
- Regardless of who has the Boston Gas and/or Mass Electric account, the Customer Participation Agreement must be signed by tenant and landlord for tenant occupied premises;
- Agree to weatherize the residence to standard energy efficiency program practices, if sufficient weatherization is not already present;
- Agree to replace all gas end uses in the residence;
- Allow reasonable access to the residence and sufficient time for the hired contractor to perform the electrification upgrades;
- Select replacement electric appliances from a menu of options, or cover the incremental cost of any such appliances if an "off-menu" option is desired (see Section 2.3.3 Equipment Selection/System Design for more information on this process);
- Comply with the timeline stipulated in the Customer Participation Agreement;
- Complete any surveys issued by the Companies for EM&V purposes;
- Consent to customer account information data sharing between Boston Gas, Mass. Electric, and any other vendors utilized by the Demonstration Program who require access to such data; and
- Agree to fully disconnect from the gas system.

Proposed System Type	**Customer Education**
Customer Appliances and Equipment covered by Targeted Electrification Demonstration Program (if currently gas)	**Contractor Obligations**
Check all that apply: ☐ Full Load Air-Source Heat Pump System ☐ Heat Pump Water Heater (up to 120 gallons) ☐ Electric Cooking Range ☐ Induction Stove ☐ Electric Clothes Dryer ☐ Electric Fireplace ☐ Other (please specify): ____________	**Check all that apply:** ☐ The contractor shall configure the eligible equipment installed in this project to be the heating source in all spaces into which it is installed. ☐ The contractor shall educate the customer about how to operate and maintain the installed new all-electric appliances. ☐ Contractor shall provide customer with printed product warranty, operation, and maintenance, and contact information.

Terms and Conditions

1. **Consent to Share Customer Information –** As part of the Targeted Electrification Demonstration Program (the "Demonstration Program"), Mass. Electric and Boston Gas (the "Company" or "National Grid") may share with each other and their contractors and designees certain information including the information provided herein such as name, address, and account number, fuel type, building type, and equipment installed, together with Customer's energy consumption data and energy savings for the National Grid accounts listed above (collectively, "Customer Information") for the purpose of implementing the Demonstration Program and evaluating the performance of the all-electric home system and energy usage. If Customer elects to have smart electric panel installed – to assist with evaluating system performance, the smart electric panel will measure energy use of the air-source heat pump. In addition, National Grid may require information from the contractor conducting the installation and/or maintenance of the air-source heat pump. By signing this Customer Participation Agreement, Customer authorizes National Grid to release Customer Information to each other, its contractors, vendors, consultants, representatives, and other designees of the Demonstration Program ("Authorized Representatives") and for Customer's heat pump installers and maintenance contractors to share all-electric home system operation and maintenance information with National Grid. National Grid is evaluating performance of the all-electric home system to obtain learnings and insights for deployment of future Targeted Electrification programs.

2. **No Incentive Double Dip –** Customers may not apply for or receive multiple incentives for the same measures from any gas or electric utility or Mass Save. Accordingly, Customer acknowledges and represents that no other financial incentive or rebate will be received from any other person or entity for the measure(s) identified in this Customer Participation Agreement issued by National Grid in connection herewith.

3. **On-Site Inspection –** National Grid reserves the right to conduct field inspections to verify installations. The Customer agrees to provide National Grid (and its subcontractors) access to the premises for pre-installation, installation, and follow-up visits upon reasonable notice, and at a time convenient to the Customer. The Customer understands that the purpose of the follow-up visit(s) is to provide National Grid with an opportunity to review the operation of the all-electric home system for quality control and Demonstration Program evaluation purposes only. Such inspections or follow-up visits do not include any type of safety review, National Grid is under no obligation to (i) make follow-up visits, (ii) review the operation of the all-electric home system, or (iii) make any suggestions of any kind to the Customer.

4. **Post-Installation Work Verification –** National Grid reserves the right to perform a verification of the specified installation.

5. **Indemnification –** Customer shall defend, indemnify, and hold harmless the National Grid and its officers, directors, employees, agents, and servants and assigns any and all losses, claims, demands and/or liability for damage to property, injury or death of any person, or any other liability incurred by the

National Grid, including all expenses, legal or otherwise, arising out of or related to the equipment or installation, except to the extent attributable to the negligence of National Grid. In no event shall National Grid's liability to Customer exceed the funding amount.

6. **Limited Scope Review –** The scope of review by National Grid and the Whole Home Electric Conversion Contractor and their inspector of the installation of the equipment is limited solely to determine the funding amount is payable. It does not include any kind of safety or code review and should not be relied upon as one.

7. **Funding Amount –** National Grid will provide payment for all approved heating, cooling, water heating, cooking, clothes dryer, and any other replacements to end-use gas appliances up to the funding amount indicated on the previous pages of this agreement. National Grid will not provide payments for non-eligible equipment.

   Electric Bill Credit – Mass. Electric will provide a monthly bill credit to the Customer's electric bill of $___ for a period of five years, commencing on _____, 20__ through and including ____, 20____. If the Customer vacates the Premises, they will no longer receive an electric bill credit at their new premises.

8. **No Warranties – Except as otherwise provided herein,** National Grid does not endorse, guarantee, or warrant any contractor, manufacturer or product installation, and National Grid disavows and provides no warranties, expressed or implied, for any produce or services that may be rendered hereunder. The Customer's reliance on warranties is limited to any warranties that may arise from, or be provided by, contractors, vendors, or manufacturers. National Grid does not make any representation of any kind regarding the results to be achieved by the equipment or the adequacy or safety of such equipment. National Grid is not responsible for any damage that may be caused by or arise out of the installation of any equipment or appliances.

9. **Removal of Equipment –** Customer agrees, as a condition of participation in the Demonstration Program, that the National Grid's contractors will remove and dispose at its sole cost and expense all equipment or materials that are replaced or removed in accordance with all applicable laws, rules, and regulations.

10. **Installation Requirements –** Customer assumes sole responsibility for installation work. Customer acknowledges and agrees that all work must be in full compliance with the requirements of applicable laws, rules, and regulations of authorities having governmental and regulatory jurisdiction. Customer is responsible for regular maintenance of all their new equipment. National Grid's contracted vendors will

provide servicing and maintenance of the air source heat pump for up to two years post installation.

11. **Gas Service Discontinuation and Access –** Customer will hold National Grid harmless for the discontinuance of the availability of the existing gas service and gas access.

12. **Gas Reconnection –**The existing gas service may not be reconnected once retired. Future need for natural gas service must be applied to in accordance with National Grid's tariffs and policies including without limitation Boston Gas's Distribution Service Terms and Conditions, M.D.P.U. No. 61, as may be amended or superseded from time to time, and associated costs would be the responsibility of the Customer. The Customer may be required to pay the full Contribution in Aid of Construction (CIAC) for the gas main replacement and service connection to reconnect to the gas network.

13. **Withdrawal of Offer/Termination –** National Grid reserves the right to withdraw this offer if Customer has not signed and returned this Customer Participation Agreement by [insert date]. National Grid also reserves the right to terminate Customer's participation in the Demonstration Program at any time prior to commencing work and installation of any of the equipment and piping on Customer's property by providing prior written notice. The Customer acknowledges and understands that participation by all other customers on the same gas pipe segment is needed for the Demonstration Program to proceed.

With this authorization, I ACKNOWLEDGE THAT MY ELECTRIC COSTS WILL INCREASE AND I WILL NO LONGER HAVE A GAS BILL, and agree to the following:

Operating cost

- I understand that the gas service and the associated bill for the Premises will be eliminated.
- I understand that electricity utility rates fluctuate and that my utility costs are determined both by the utility rates and by my energy consumption.
- I understand that this heat pump system may be used for cooling in the summer and will be used for heating primarily in the fall, winter, and spring.
- I understand that due to the year-round operating schedule for all my new electric appliances, I may consume more electricity monthly than before.
- I understand that my use of this heat pump system for cooling may increase my electric bills in the summer.
- I understand that, when I operate my heat pump for heating, I will use significantly more electricity and will therefore have higher electric bills during the heating season.
- I understand that I can speak with my electric utility company about budget billing options to provide a predictable monthly electric bill to help manage costs. If I am interested in budget billing, I will contact my electric utility.

- I understand that when Mass. Electric has a Heat Pump Rate approved and implemented, I will be enrolled in this rate due to my participation in the Demonstration Program and upon the installation of the heat pump.
- I understand that if approved by the Massachusetts Department of Public Utilities, I will receive a monthly credit on my electric bill for up to 5 years if I participate in the Demonstration Program.
- I understand that in 5 years, when the bill credit ends, my electric bills will go up.
- I also understand that in the future there may be alternative rates and/or demand response programs that may mitigate cost associated with increased electric usage.

Initial ________

Maintenance & Service

- I understand that routine maintenance and scheduled service are essential for any heating system to provide efficient, reliable operation long term and are especially important to the operation of heat pumps. Failure to properly maintain heat pumps will decrease efficiency (thereby increasing operating cost) and may lead to operating failure.
- I understand that, due to their nature as both heating and cooling systems and filtration and dehumidification devices, heat pumps have unique and essential maintenance requirements.
- The Demonstration Program and Mass Save are paying for 100% of the installation costs for my new electric appliances. The Demonstration Program will also provide routine annual maintenance for my air source heat pump at no cost to me for 2 years after the installation is complete. My other new appliances will be covered under their manufacturer warranties. I will allow access to my appliances for this purpose when requested by National Grid and/or its contractors the free maintenance period.
- I will be responsible for scheduling and paying for any maintenance that the heat pump system may require, after the two-year period provided by the Demonstration Program. I understand that some scheduled services may be required to keep my new electric appliances operating effectively.

Initial _______

Customer Acknowledgment

I certify that all information I filled in above is correct to the best of my knowledge. I have read and agree to the terms and conditions for Customers Participation Agreement for the Targeted Electrification Demonstration Program and consent to the sharing of Customer Information specified herein.

____ ________________

Customer Signature Date

Timing Expectations (ILLUSTRATIVE)

Work schedules will vary per individual home needs; however, the customer must plan to adhere to the rough calendar below.

September	9/1-9/30
	• Sign and return National Grid Customer Acknowledgment • Select needed electric appliances with desired provider • Sign contract with National Grid's contractor
October	10/1-10/31
	• Electric system upgrades
November	11/1-11/30
	• Complete in-home pre-weatherization and pre-electrification work, as needed • Weatherize home • Electric appliances installation
December	12/1-12/31
	• Commissioning and testing of new all-electric home system to ensure working properly • Shut off gas service
January	1/1-1/31
	• Retire the gas service at the distribution main

ATTACHMENT B – Illustrative Marketing Materials[39]

[39] Note: This brochure is a sample of one type of marketing and educational asset for eligible customers. It is for illustrative purposes only, and subject to change based on additional research and analysis of the customer market.

How Does It Work?

1. Commit to Clean Energy
For the project to move forward on your street, all neighbors on the identified pipe segment must participate. Together, we'll help reduce carbon emissions, improve air quality, and upgrade your home.

2. Schedule a Home Energy Assessment
A Home Energy Assessment will evaluate the current state of your energy system, appliances, and usage. It will also provide information on the Whole-Home Electrification Program offerings that are customized to your home.

3. Home Upgrades in Preparation for Electrification
We'll provide energy efficiency upgrades to your home as well as any necessary improvements to your electric panel to maximize your home's efficiency and ensure it's ready for electric conversion.

4. Whole-Home Electrification
We'll professionally install a new air source heat pump and state-of-the-art electric appliances. We'll also remove and dispose of your old appliances for you. Once all new appliances are up, running, and working well for you and your neighbors, we'll disconnect gas service and remove and dispose of your old gas meter.

Ready to learn more?

Visit **ngrid.com/xxx** or scan the QR code

Call **XXX-XXX-XXXX**

FPO

EE100231 (10/24)

SAMPLE

nationalgrid

Whole-Home Electrification Program

No-Cost Home Electric Conversion. Cleaner. Greener. More Comfortable.

Transform your home with state-of-the-art electric appliances and energy efficiency upgrades—at no cost to you! Join the movement toward a cleaner, greener, and more comfortable home environment by switching from natural gas to all-electric systems.

ngrid.com/xxx

SAMPLE

What is the Whole-Home Electrification Program?

We are launching an exciting new initiative to help a select group of customers transition from natural gas to all-electric homes at no cost. As part of this program, we will replace your current gas appliances with modern electric alternatives, including energy-efficient air source heat pumps (ASHP), electric water heaters, stoves, and dryers. We also take care of essential upgrades like electric panel enhancements and energy efficiency improvements, making your home more comfortable and environmentally friendly. You and your neighbors who have been selected as eligible are invited to make the switch to clean energy at no cost.

100% No-Cost Conversion
You'll receive brand-new electric appliances and professional installation—all covered by the project. This includes ASHP for heating and cooling, upgraded water heaters, stoves, dryers, and more.

Commit to Clean Energy
For the project to move forward on your street, all neighbors on the identified pipe segment must participate. Together, we'll help reduce carbon emissions, improve air quality, and upgrade your home.

Ongoing Support
Our team will be with you every step of the way, ensuring a smooth transition and answering any questions you may have about the new technology.

Why Participate?

New Heating and Cooling System and Appliances at No-Cost
Receive comprehensive whole-home electrification, including weatherization, a new heating and cooling system, and modern electric appliances, with no out-of-pocket expenses.

Cleaner, Healthier Home
Switching to electric appliances reduces your home's carbon emissions by 45-72%.

Enhanced Comfort
Experience year-round comfort with an air source heat pump, providing both heating and cooling.

Smart Investment
Upgraded, energy-efficient heating systems and appliances can enhance a home's value and future resale potential.

Flood-Resilient
Outdoor air source heat pump units are safer from flooding risks compared to traditional gas heating systems.

Bill Credit
As part of this conversion, you will no longer receive a gas bill. By participating in this program, you will receive a monthly electric bill credit for 5 years after conversion, making the shift to all-electric more affordable.