The power-gas demand impacts and regulatory implications for the future of gas systems under the electrification of space heating in cold climates

by

Morgan Santoni-Colvin

B.S. Mechanical Engineering
The University of Texas at Austin, 2021

Submitted to the Institute for Data, Systems, and Society
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE IN TECHNOLOGY AND POLICY

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

September 2023

Authored by: Morgan Santoni-Colvin
Institute for Data, Systems, and Society
August 11, 2023

Certified by: Leslie Norford
Professor
Department of Architecture
Thesis Supervisor

Certified by: Audun Botterud
Principal Research Scientist
Laboratory for Information and Decision Systems
Thesis Supervisor

Accepted by: Frank R. Field III
Senior Research Engineer, Sociotechnical Systems Research Center
Interim Director, Technology and Policy Program

The power-gas demand impacts and regulatory implications for the future of gas systems under the electrification of space heating in cold climates

by

Morgan Santoni-Colvin

Submitted to the Institute for Data, Systems, and Society on August 11, 2023 in partial fulfillment of the requirements for the degree of MASTER OF SCIENCE IN TECHNOLOGY AND POLICY

Abstract

The call for action to mitigate GHG emissions necessitates the decarbonization of the building sector. The electrification of heating, especially via efficient air-source heat pumps coupled with a low-carbon electricity grid, is considered an attractive option for displacing emissions from fossil-fueled heating systems. While the opportunity for decarbonization is high in emission-intensive housing stocks such as that of the U.S. New England region, the high demand for heating in cold climates elicits concerns about energy demand impacts. Furthermore, there is concern about what electrification and the broader call for decarbonization might imply for gas distribution systems, which will face declining usage and most likely infrastructural retirement.

First, this thesis develops a bottom-up building energy modeling framework to quantify the hourly power and gas demand impacts of the electrification of residential heating in New England under a range of electrification and weather scenarios for 2050. We find that deep electrification greatly diminishes gas demand and increases electricity demand, with a potentially drastic increase in peak electricity demand given current technologies. Furthermore, the weather-induced variation in peak demand becomes more drastic. These adverse demand impacts can be mitigated by envelope improvements and motivate the implementation of demand-side flexibility, but the effectiveness of these measures may be limited by long peak demand durations. However, the adverse demand impacts of deep electrification must be weighed against the downsides of less-aggressive electrification, which might actually result in worse demand impacts in the long term. Second, we compare the current future gas system planning frameworks of Massachusetts regulators against other states, finding that policymakers in Massachusetts must address several issues in order to prepare for the transformative effect that electrification will have on gas distribution systems. Resulting recommendations highlight the need for continuous long-term gas planning procedures, legal reform of the consumer right to gas service, a cautious approach towards considering alternative fuels as a mechanism for gas system decarbonization, and prioritization of equity in allocation of the costs of gas system retirement.

Thesis Supervisor: Leslie Norford
Title: Professor

Thesis Supervisor: Audun Botterud
Title: Principal Research Scientist

Acknowledgments

Writing this thesis (and completing this program) could not have been possible without the love and support of a great many people. Thanks firstly to my family for always indulging my curiosity and aspirations, and for supporting me through thick and thin. Much love to the wonderful friends who've taken me into their lives since moving to Cambridge – (in no particular order;) Nicole, Kailin, Anke, Paul, Serena, Les, Edgar, Philipp, and countless others who no doubt deserve to be named but would perhaps fill the rest of this page. Thank you to Anita for reminding me to take in the little beauties of life. I owe infinite gratitude to my many academic mentors before and during my time at MIT: Prof. Ben Leibowicz for facilitating my introduction to the world of energy systems and research as an undergraduate, my thesis supervisors Prof. Les Norford and Dr. Audun Botterud for providing me wisdom and humor on (at least) a weekly basis, Prof. Saurabh Amin for stimulating discussions, and Dr. Dharik Mallapragada and Rahman Khorramfar for being attentive and generous collaborators.

Table of contents

List of figures

List of tables

1. Introduction

The challenge of climate change calls for the decarbonization of our energy systems. The buildings sector, the direct emissions of which make up 13% of annual emissions in the United States (US EPA, 2015), will play a large role in reaching objectives for GHG emissions reductions. Fossil gas (hereinafter, 'gas') contributes significantly to the building sector's emissions, accounting for 80% of direct fossil fuel end-use in the residential sector (U.S. Energy Information Administration (EIA), 2021). Because space heating (i.e., the heating of occupied spaces for human thermal comfort) is the principal end-use of gas in the building sector (E. Wilson et al., 2022), it must be prioritized in decarbonization efforts.

The electrification of residential heating via efficient air-source heat pumps (ASHPs) coupled with a low-carbon electricity system stands as a widely-accepted primary path forward in decarbonizing space heating (International Energy Agency (IEA), 2022b). The key benefit of ASHPs relative to other technologies is that they use ambient thermal energy "pumped" from the air outside of a building to produce useful heat within it, enabling efficiencies of greater than 100%. ASHPs can also be run in reverse to function like a typical air conditioner. Heat pump technology has advanced significantly in recent years, enabling greater efficiency and lower operating costs and thus enhancing their attractiveness to policymakers.

However, the potential demand impacts of electrification are cause for concern among stakeholders. Transitioning to electrified heating systems portends large increases in electricity demand (Deetjen et al., 2021; Waite & Modi, 2020; White et al., 2021), potentially requiring extensive supply-side investment in power systems and a shift to winter-peaking power demand (White et al., 2021), which carries with it health and safety risks associated with power outages during extreme cold events (Keskar et al., 2023). Because heating is a weather-sensitive load, heating electrification also potentially increases weather-induced variability in interannual demand patterns (Staffell & Pfenninger, 2018). Quantifying this demand variation is critical to enabling planners to make decisions under future demand uncertainty, for example, in determining the need for firm power generation capacity in the integrated power-gas system. The evaluation of the demand impacts of residential electrification in cold climates is imperative to assessing relative risks, benefits, and costs of different future electrification pathways.

Furthermore, and at emphasis in this thesis, is that the electrification of space heating threatens the role of the gas distribution grid. In the United States, an extensive gas sector exists in order to serve high demand across the economy. The nation's gas system underwent massive expansion throughout the 20th century, with investments continuing through the present day (U.S. Energy Information Administration (EIA), 2022). Electrification will likely cause a drastic and rapid shift in this trend. As buildings switch from gas-based heating systems to electrified ones, gas usage will decrease, potentially necessitating the retirement of gas distribution systems.

A core issue lies within the nature of the utility business model. Utilities are effectively natural monopolies and are heavily regulated at both the state and national levels (Joskow, 2007). In the contemporary context, the practice of "revenue decoupling" in restructured utility markets means that gas utilities do not collect revenue based on volumetric sales. Instead, their capital investments in pipeline infrastructure are under close oversight of regulators, who determine what "just and reasonable" rates they can charge to gas consumers ("ratepayers") such that they can depreciate their assets over an extended (often multi-decade) time horizon while collecting a pre-defined return through a process referred to as "cost recovery". Typical ratemaking procedures only entitle a utility to recover the costs of an asset if it is "used and useful" to the public, meaning gas utilities have a standing incentive to seek continuation of gas usage such that they can fully depreciate their assets and continue building and depreciating new assets. Relatedly, the potential early retirement of gas infrastructure in alignment with climate objectives poses an enormous stranded asset risk, the depreciation costs of which will have to be borne by utility shareholders, ratepayers, or some other group.

State policymakers face the difficult task of determining how to best facilitate the decarbonization of their gas systems under these circumstances. Key questions center on the degree to which electrification, gas system retirement, and potentially the usage of low-carbon alternative fuels to preserve the status quo gas system must be balanced against one another as strategies that can simultaneously reduce negative cost outcomes and reliably facilitate rapid decarbonization.

1.1. Scope and research questions

In evaluating the demand impacts and policy implications of electrification and what it means for gas infrastructure, New England serves as a particularly valuable case study in the US context. The region's cold climate and relatively old housing stock result in disproportionate emissions from building gas usage for heating; direct emissions from residential gas usage account for 8% of its economy-wide emissions in New England in 2021 as opposed to the national average of 5% (U.S. Energy Information Administration (EIA), 2023a). Figure 1 shows the fraction of homes in each New England state that use a given heating fuel, revealing that natural gas makes up a significant component of the heating stock, notably in the more populous states of Massachusetts and Connecticut.

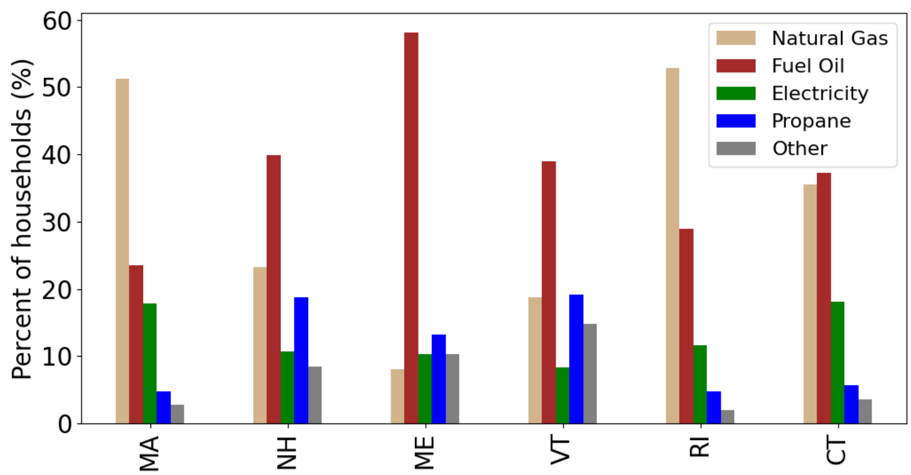

Figure 1. Proportions of home heating fuels in New England by state. Data from EIA (U.S. Energy Information Administration (EIA), 2023b).

With respect to the state policy and regulatory issues within New England, Massachusetts is illustrative, given the state's large population, high gas usage, and ambitious electrification goals. Beginning with its Global Warming Solutions Act in 2008, which set a legally binding emissions requirement for mid-century of 80% below 1990 levels (An Act Establishing the Global Warming Solutions Act, 2008), Massachusetts has pursued increasingly aggressive decarbonization policy. The Commonwealth has also given recent attention to the issues of building decarbonization, electrification, and the future of its gas systems. For example, the state’s recent Clean Energy and Climate Plan for 2050 calls for even deeper reductions beyond the Global Warming Solutions Act, with a goal of net-zero by 2050, and outlines a number of electrification pathways to meet the building sector’s emissions goals (Massachusetts Executive Office of Energy and Environmental Affairs, 2022).

In light of the above, this thesis primarily seeks to address two core research questions:

1. What are the power and gas demand implications of heat electrification in New England in 2050?
2. What are the regulatory issues and possible approaches with respect to the future of gas in Massachusetts, with a particular emphasis on the gas distribution grid serving the residential and commercial sectors?

A quantitative method is developed and presented to answer the first question. For the second question, we undertake a comparative analysis of recent policies and regulations in multiple US states. This comparative analysis leads to regulatory and policy recommendations for planning the future of the gas system in Massachusetts.

2. Power and gas demand impacts of heat electrification in New England

Projecting the future demand impacts of heat electrification is a prerequisite to making system planning and policy decisions relating to infrastructure investment, operation, and retirement. Assets such as power plants, energy storage facilities, and transmission lines must be planned and constructed proactively to meet what could potentially be a very rapid change in the magnitude and temporal patterns of energy demand. Evaluating demand impacts at an hourly resolution is a necessary exercise for extracting insights that are most relevant to grid planning (Craig et al., 2022). For example, future decarbonized grids will likely include large amounts of variable renewable energy (VRE) resources such as wind and solar coupled with battery storage, for which the optimal amount of capacity hinges on both the magnitude and timing of hourly peak demand and how it correlates with these resources (Bloomfield et al., 2016; Deakin et al., 2021). Furthermore, spatially resolved analysis is needed in order to properly characterize the heterogeneous sub-regional impact of electrification due to spatially diverse features including differences in physical characteristics of the housing stock (e.g., housing size and materials) and weather.

Modeling approaches to estimating the energy demand of the building sector vary widely, spanning the breadth of statistical, engineering, and econometric models, among others (Langevin et al., 2020). A nascent section of the literature revolves around the so-called "bottom-up building energy models", which rely on engineering models to simulate the hour-to-hour heat transfer, controls, and occupant behavior of a set of archetypal buildings that collectively represent a larger population thereof (Langevin et al., 2020; Swan & Ugursal, 2009). Besides these building stock characteristics, the bottom-up framework also takes weather data as a key input that drives energy demand. A primary benefit of the approach is it enables the evaluation of "what-if" scenarios for prospective future building stocks, including those under deep electrification, for which historical data does not exist. While for many years the bottom-up approach has generally used just a handful of archetypal buildings (Ballarini et al., 2014; Tarroja et al., 2018), more recent advances in computational speed and methods have enabled researchers to develop models that leverage large numbers of archetypes to more realistically represent the diversity in building stock and consumption behavior (Cerezo Davila et al., 2016; E. J. Wilson et al., 2017). NREL's ResStock model, which is used as part of the demand modeling framework in this study, represents a significant recent advance in bottom-up modeling (Mims Frick et al., 2019; E. J. Wilson et al., 2017).

When it comes to demand-side assessment of heat electrification impacts, the literature generally neglects some key considerations. A key but undertreated issue is the question of heat pump sizing. Many proponents and state policies favor a "whole-home heating" or "winter-sized" approach where a heat pump is a home's sole source of heating through the heating season. For example, with the Mass Save heat pump rebates offered in Massachusetts, households that undertake whole-home electrification automatically qualify for the maximum rebate amount (Mass Save, 2023b). Others suggest that "hybrid" or "summer-sized" systems, where ASHPs are sized for the cooling season and coupled with backup fossil heat for higher winter demands, can provide sufficient decarbonization at lower household and supply-side cost, particularly in cold climates (Eversource Energy, 2022; Waite & Modi, 2020). There is disagreement about which approach offers the best pathway for balancing cost-effective emissions reductions with undesired system impacts. The literature has focused on the impacts of whole-home heating electrification (Deetjen et al., 2021; Vaishnav & Fatimah, 2020; White et al., 2021). To the extent it has considered hybrid heating, it has only examined the demand impacts of 100%

adoption (Waite & Modi, 2020) and has not considered the adoption of hybrid and full-home systems as simultaneous strategies aligned with the realistic deployment outcomes that will result from heterogeneous policy, household preferences, and behavior.

Additionally, little consideration has been given in the bottom-up literature to the demand impacts of interannual weather variation. The energy demand for heating and cooling is highly dependent on weather, primarily due to how ambient conditions impact demand for heating and cooling services and the efficiency of heating, ventilation, and air conditioning (HVAC) systems. ASHPs in particular warrant consideration of weather impacts because their heating efficiency (i.e., the units of electricity in versus the units of useful heat out) is highly dependent on outdoor air temperature, a phenomenon made more problematic because high heating demand often correlates with colder weather. Studies often only evaluate demand impacts of ASHPs under a single year of weather, however, system planning must be made with consideration of interannual variation in weather patterns in order to design robustly to weather extremes (Staffell & Pfenninger, 2018).

Lastly, the bottom-up modeling literature fails to evaluate the role envelope improvements (also known as "weatherization", i.e., retrofits to improve the thermal efficiency of a building's exterior) can have in reducing adverse demand impacts from electrification. Envelope improvement programs are well-established in the US (U.S. Department of Energy, n.d.) and are widely identified as an important part of decarbonizing the building sector in parallel with electrification (International Energy Agency (IEA), 2022a; Li & Colombier, 2009), making them necessary to consider.

The demand estimation methodology in this thesis, presented in more detail below, addresses these gaps in order to obtain an informative depiction of future electrification demand impacts in New England for the year 2050 across a number of key metrics. Leveraging the ResStock model to calculate heating and cooling demands with and without envelope improvements, a heat pump model is devised to appropriately reflect heterogeneous sizing practices across multiple heat pump adoption scenarios. A 20-year portfolio of weather data is used to evaluate the potential interannual variability in demand impacts of heat electrification in the region.

2.1. Methodology

The methodology is summarized in Figure 2 below.

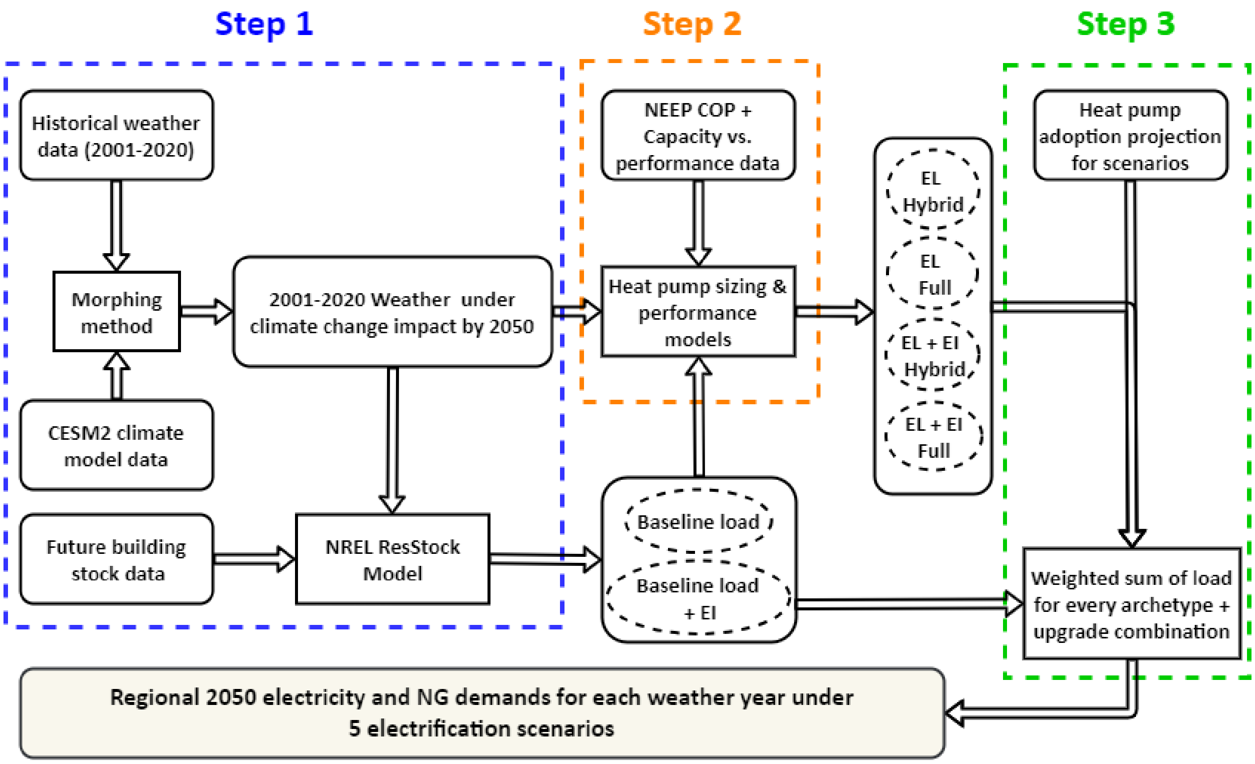

Figure 2. Diagram of bottom-up modeling methodology.EL = Electrified, EI = with envelope improvements. "Full" and "Hybrid" correspond to the two heat pump sizing methods applied in this study.

In the first step of the demand modeling, we leverage NREL's ResStock model. Given the housing stock characteristics and weather, ResStock generates a sample of housing archetypes and simulates their hourly energy consumption for key end-uses. Step 1 determines energy demands for the archetypes using future weather and building stock projections. In step 2, we develop a heat pump modeling method that determines the electricity and gas demands for the archetypes when they are electrified under different mixes of heat pump sizes and envelope upgrades. Step 3 aggregates the demand profiles of all of the archetypes to determine the hourly regional loads for the residential sector while accounting for the mix of possible heat pump sizes and envelope improvements applied to the stock. In this section, these core computational portions of the workflow will be detailed first, with other methods used to calculate inputs (such as weather and building stock change projections) following thereafter.

2.1.1. Step 1: ResStock modeling

ResStock produces two key outputs: heating-and-cooling-related thermal loads, which is the thermal energy required to maintain comfort in the living space, and non-heating-and-cooling-related fuel demands such as natural gas demand for water heating and cooking.

Our modeling relies on archetypes that collectively represent the residential building stock. Because each archetype represents a group of many identical homes that may receive varying upgrades, we define so-called *sub-archetypes* to represent each of these variants. The *baseline* sub-archetype is the original version of the archetype, with no upgrades. The *electrified* sub-archetypes capture different possible mixes of heat pump sizing and envelope upgrades applied to the baseline sub-archetype (which we refer to as *upgrade packages*). The electrified sub-archetypes are as follows:

1. Summer-sized (”hybrid”) heat pump, no envelope upgrades

2. Summer-sized (”hybrid”) heat pump, with envelope upgrades

3. Winter-sized (”whole-home”) heat pump, no envelope upgrades

4. Winter-sized (”whole-home”) heat pump, with envelope upgrades

Thermal loads for heating and cooling in the baseline sub-archetypes are necessary inputs for our modeling of the electrified sub-archetypes. ResStock provides data for heating and cooling thermal loads if and only if heating and cooling systems are present in the simulated building, which is not the case for every baseline sub-archetype in New England. To retrieve these loads, we use ResStock to apply an upgrade to every baseline sub-archetype such that it has a heating and cooling system. In particular, we apply an upgrade of a typical single-speed air-source heat pump (in ResStock: “HVAC Heating Efficiency - ASHP, SEER 15, 9.0 HSPF”). ResStock also provides the fuel demands corresponding to the new air-source heat pump upgrade, however, we opt to use a different method because the ResStock method largely relies on inefficient electric resistance backup heating. Instead, we develop a heat pump model that more accurately approximates industry standard sizing methods for cold-climate regions such as New England (details in later section).

Envelope improvements and water heat electrification

Our scenarios consider envelope improvements which refer to all post-construction upgrades made to the building exterior to reduce heat loss and improve thermal efficiency. Examples of these activities include adding insulation and sealing air leaks. We use ResStock to generate thermal loads in the presence of basic envelope upgrades for both the baseline and electrified sub-archetypes. We approximately align these improvements with the improvements specified in the "ECM2 – Medium Efficiency" package outlined in the Building Sector Report of the Massachusetts 2050 Decarbonization Roadmap Study (Commonwealth of Massachusetts, 2020), which includes the lowest degree of envelope improvements considered in the report, and is thus what we assume to be a basic level of envelope retrofit. ResStock offers a discrete list of improvement options that do not necessarily match a level shown in the Roadmap. We show the comparisons in Table 1 below.

Table 1. Translation of Massachusetts Decarbonization Roadmap envelope improvements to ResStock equivalents.

Upgrade	MA Decarbonization Roadmap	ResStock equivalent
Roof/Ceiling insulation	R-60	R-60
Wall insulation	R-15	R-13
Sheathing insulation	N/A	R-5
Rim joist insulation	N/A	R-13
Foundation wall insulation	N/A	R-10
Infiltration reduction	0.4 CFM/sf at 0.3 in. wc.	2.25 ACH50

In addition to an air-source heat pump, we assume that electrified sub-archetypes also receive a heat-pump water heater (HPWH). We model this in ResStock by selecting a 66-gallon HPWH with a uniform energy factor (UEF) of 3.35, which is the least efficient (and therefore most conservative) choice available in ResStock. Beyond space and water heating, we do not consider the electrification of other residential end-uses.

2.1.2. Step 2: Heat pump model

We use the thermal loads provided in ResStock as inputs to our modeling of heating and cooling demand for the electrified sub-archetypes. ResStock provides thermal loads for a single living space representing the entirety of the home. Therefore, our models assume the home will be heated by a single heat pump, although in reality, some households may opt for multiple smaller heat pumps.

2.1.2.1. Data underlying the heat pump model

Our ASHP model is based on applying statistical linear regression to the large "Cold-Climate Air Source Heat Pump" dataset from NEEP (Northeast Energy Efficiency Partnerships, 2023). The NEEP dataset includes data for thousands of cold-climate heat pumps that are submitted by manufacturers. Key characteristics of heat pump performance and the associated fuel demands rely on the operating conditions. In our models, we primarily consider the effects of outdoor air temperature (i.e., ambient temperature). This is common in the literature (Vaishnav & Fatimah, 2020; Waite & Modi, 2020). The NEEP dataset provides capacity and efficiency values at multiple temperatures for all ASHPs listed in the dataset. We preprocess the dataset to form the basis of our regression model. First, we filter for models with Heating Seasonal Performance Factor (HSPF) equal to 10, the level currently required to qualify for electrification incentives in Massachusetts (Mass Save, 2023a). In order to avoid extrapolating beyond the range of our regression data, we then filter for models for which the manufacturer provided data for performance below -15 °C (5 °F). We then remove duplicate data which leads to some heat pumps being over-represented in the dataset. We note that because some heat pumps in the dataset are likely to be more popular than others, this does not result in an aggregate of the most likely heat pump to be adopted, but rather an approximation of the "average" HSPF 10 heat pump on the market.

2.1.2.2. COP model

The hourly *coefficient of performance* (COP) or efficiency of the heat pump determines the ratio of the useful thermal energy supplied to (or removed from) the space to the electricity consumption in a given hour, as shown in Equation 1.

$$COP_{heat} = \frac{|\dot{Q}_{out}|}{\dot{E}_{in}} \tag{1}$$

The COP for heat pumps in heating mode decreases in colder temperatures. Similarly, warmer temperatures adversely impact the COP of heat pumps in cooling mode. We compute the hourly COPs as a function of the hour's outdoor air temperature. In addition to temperature, COP varies with the "part-load ratio" which is the amount of energy the heat pump supplies relative to its maximum capacity at the operating outdoor air temperature. To simplify the model, we do not consider part-load performance, an assumption made in similar studies (Vaishnav & Fatimah, 2020). The temperature-vs.-COP function is based on a least-squares linear regression of the COP and temperature values listed in the NEEP dataset. The NEEP dataset lists multiple COPs for a given temperature depending on the part-load ratio of the heat pump. We use the COP values for heat pump operation at maximum capacity. There are separate COP curves for heating and cooling:

$$COP_{heat,h} = f(T_h) = 0.045T_h + 2.73 \tag{2}$$

$$COP_{cool,h} = f(T_h) = -0.116T_h + 7.35 \tag{3}$$

where T_h is the parameter for the hourly temperature in degrees Celsius. Our linear model for heating mode, as shown in Figure 3, is inherently a simplification of reality. According to performance testing, the dependence of COP on temperature is non-linear (Shoukas et al., 2022). For our heating COP dataset, linear and quadratic fits result in essentially equivalent curves, suggesting that additional model complexity would not necessarily result in a better fit at the expense of tractability. Similarly, Figure 4 shows the regression model for COP in cooling mode.

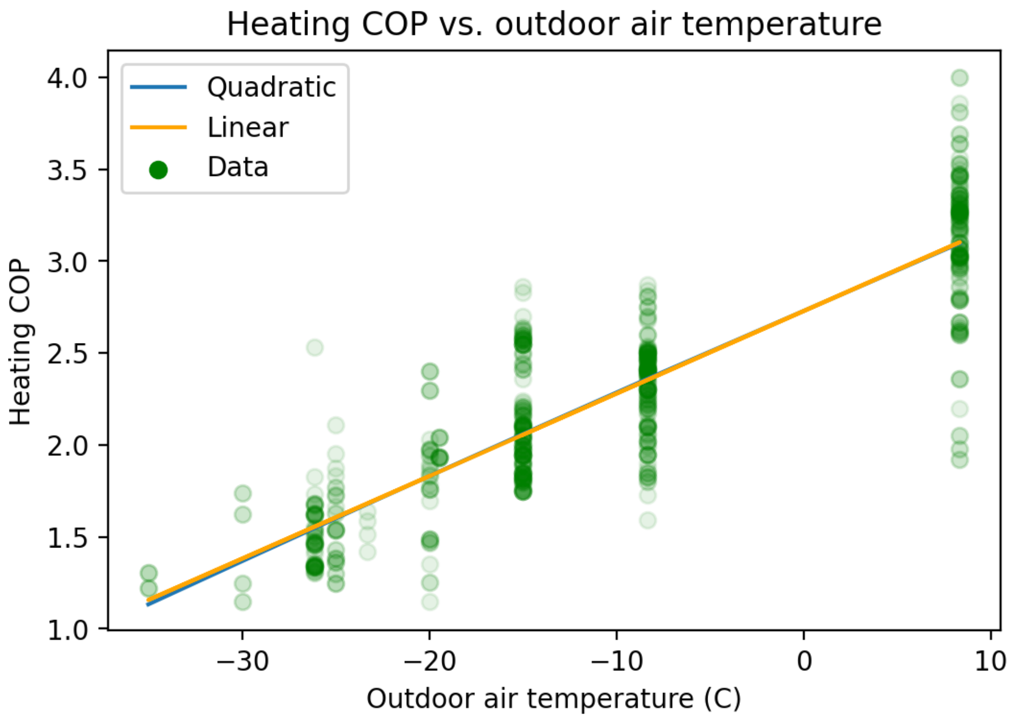

Figure 3. Regression model for heating COP versus outdoor air temperature. The linear fit is shown to be essentially equivalent to the quadratic fit.

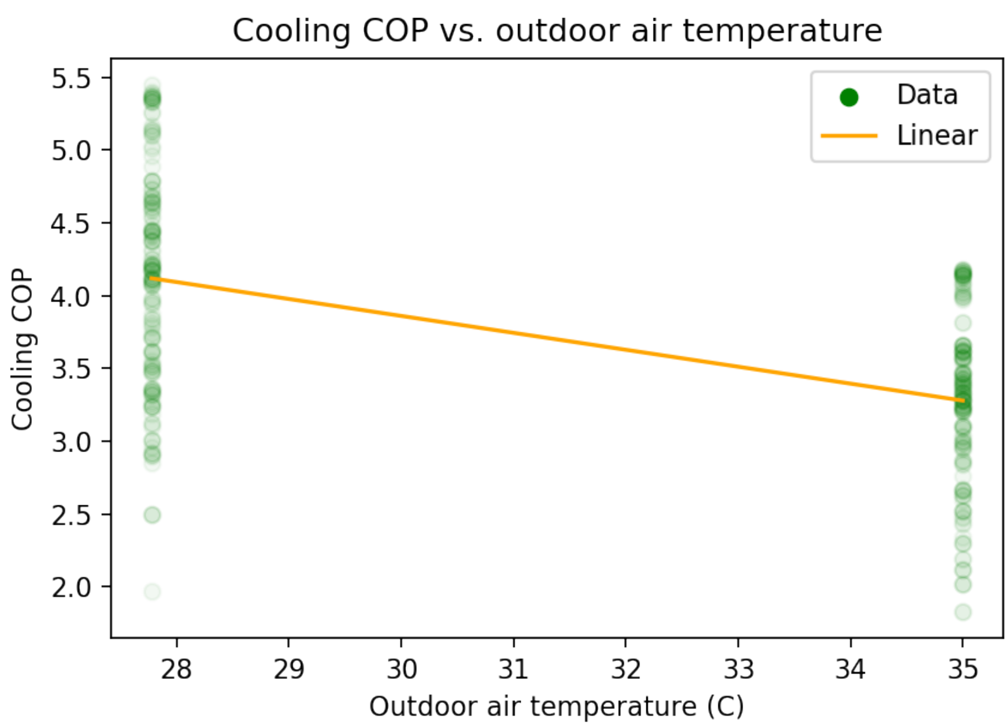

Figure 4. Regression model for cooling COP versus outdoor air temperature.

2.1.2.3. Heating capacity derating model

The *capacity* of a heat pump refers to the maximum heating or cooling output it can produce. Similar to COP, the capacity depends on temperature, such that colder temperatures generally reduce the heating capacity of a heat pump relative to warmer temperatures, and vice versa. Colder temperatures typically imply higher heating loads within a building; because this coincides with reduced heating capacity in the heat pump, there is a temperature range for which heating supply cannot keep up with heating load. The modeling of capacity derating enables us to identify hours in which the heat pump's capacity is less than the heating load, when backup heating may be necessary (discussed in more detail later in this section). Therefore, our model incorporates temperature-related capacity derating for heating. In addition to COP values at each temperature, the NEEP dataset contains heating capacity values. For the ASHP models represented in the dataset, there are maximum and minimum capacity values provided for each temperature. Such a range of capacities can be present in a variable speed system, which has a compressor speed that can be modulated via controls, meaning there can be a range of capacities for a given temperature. We assume that for a given heat pump model represented in the dataset, the capacity value at a given temperature is the maximum value listed in the dataset. To obtain a model for the capacity derating, we take a regression of the capacity values across the dataset for all models, normalized compared to the capacity at 8.3 °C (47 °F) of each respective model. This enables us to obtain a slope that represents the average percentage loss of heating capacity for every degree Celsius drop in temperature, for all heat pumps represented in the dataset. The capacity value for a given hour, Ch, is calculated as

$$C_h(T_h) = (1 - 0.0153 \cdot (T_{sizing} - T_h)) \cdot C_{sizing} \qquad (4)$$

We first define a *sized capacity*, C_{sizing}, the capacity at which the heat pump is sized at the sizing temperature, T_{sizing}. The sizing method is discussed in the next section and differs depending on the sizing method. We assume the decrease in the capacity below T_{sizing} is proportional to the slope obtained from the regression in our capacity derating model. Note that the logic also applies in reverse, e.g., if we assume that the heat pump is running at an outdoor air temperature 10 degrees above the sizing temperature, the heat pump has a capacity 15.3% higher than the capacity at the sizing temperature. Similar to the COP model, our linear model for heating capacity abstracts away from potential non-linearities in the temperature dependence of heating capacity, which is empirically the case (Shoukas et al., 2022). Our model is depicted visually in Figure 5.

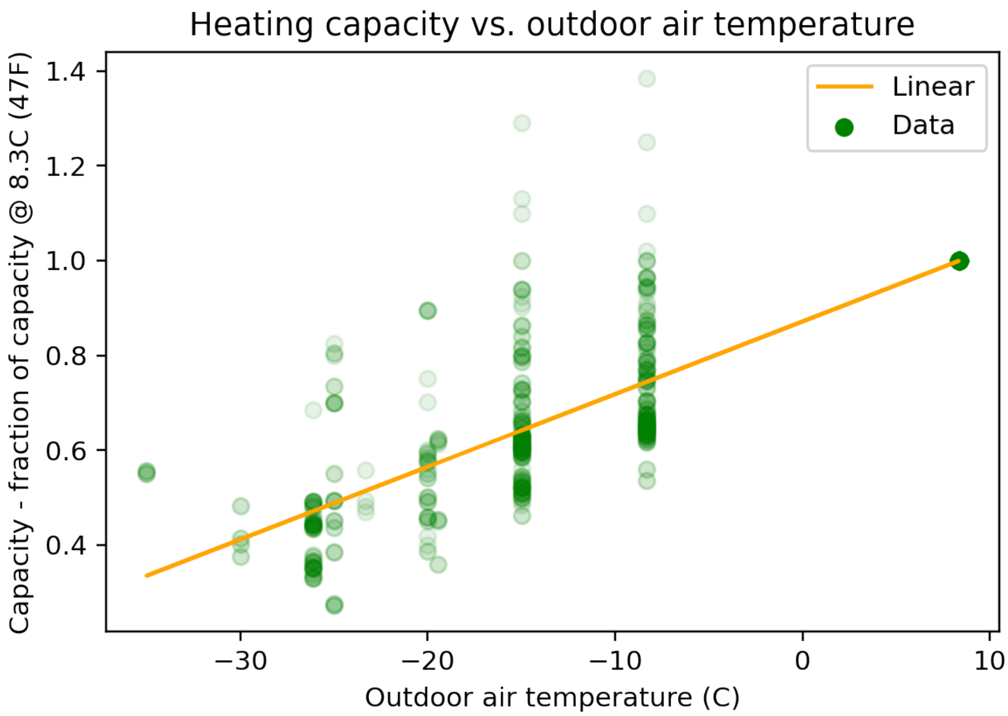

Figure 5. Regression model of heating capacity versus outdoor air temperature.

As a way to simplify our model, we do not consider capacity derating for cooling. The NEEP capacity data suggests that cooling capacity declines only modestly with increases in temperature. Additionally, given the dominance of heating loads over cooling loads in our study area, cooling capacity derating is less relevant to determining important hourly demand phenomena such as peak electricity loads.

2.1.2.4. Sizing Model

A key consideration in installing a heat pump is its *size*, that is, the chosen capacity. In our analysis, we define two possible sizing methods during an installation: sizing a smaller heat pump, primarily for cooling (summer sizing), and sizing a larger heat pump, primarily for heating (winter sizing). Both systems provide some amount of heating in the winter, with the winter-sized system intended to heat throughout the year. For each archetype, we size heat pumps for summer and winter approximately according to current and proposed ACCA S methods, a set of industry-standard guidelines for HVAC sizing (W. Davis, 2022). As inputs to our sizing methods, we leverage data for the typical meteorological year (TMY) (Wilcox & Marion, 2008) to produce archetype loads and temperatures from ResStock corresponding to typical weather conditions. We do this as part of an attempt to approximate the ACCA S sizing methods' usage of long-run weather averages to determine the design conditions. Our sizing methods differ from ACCA S in that we use the delivered heating or cooling loads rather than so- called "design loads," both of which are modeled outputs but generated through different methods. We do this because the latest version of ResStock did not provide design loads for winter-sized heat pumps as an output at the time of our analysis.

Winter sizing

In the case of winter sizing, the size of the installed heat pump is primarily determined by the heating load. For each archetype, we first take the 99th percentile hourly heating load from the year of TMY data and "size" the heat pump such that it can provide this capacity C_{sizing} at the sizing temperature, T_{sizing}. In the case of winter sizing, we use the 1st percentile temperature. Because the 99th percentile load often occurs at temperatures above the 1st percentile temperature, many of our archetypes effectively meet 100% of the load across the typical meteorological year.

The cooling capacity is tied to the heating capacity. Generally, the nameplate heating and nameplate cooling capacity of a heat pump are similar, where the nameplate heating capacity is the capacity at 8.3 °C (47 °F) and the nameplate cooling capacity is the capacity at 35 °C (95 °F). Analysis of our dataset shows that these values are on average within about 4% of one another. Therefore, we assume the heating and cooling nameplate capacities are equal. Because we do not model cooling capacity derating, we effectively set the temperature-invariant cooling capacity as equal to the derated capacity of the heating system at 8.3 °C (47 °F).

Because we only use a single capacity curve, our heat pump models and the associated sizing methods do not consider the potential issue of "short-cycling," which is rapid on-off switching that may occur when the heating or cooling demand is below the heat pump's minimum capacity at the operating temperature. Although variable speed systems offer a range of capacities at any given temperature, this may still occur, particularly in winter-sized systems, leading to humidity control issues that would generally be desired to be avoided in the sizing calculations. We assume the combination of our sizing methods and heat pump operation does not result in excessive short-cycling that would necessitate different installation configurations.

Summer sizing

In the case of summer sizing, the size of the installed heat pump is primarily determined by the cooling load. For each archetype, we take the 99th percentile cooling load from the TMY data and size the heat to provide 130% of this capacity at T_{sizing} where T_{sizing} is the 99th percentile temperature. The 130% factor approximates the ACCA S method for sizing a heat pump primarily used for cooling in a heating-dominated climate. Hence, we use it as the basis of our method for "summer-sized" systems. The heating capacity is linked to the cooling capacity. Similar to winter sizing, we assume the heating nameplate capacity is equal to the cooling capacity.

2.1.2.5. Backup system configurations

In our primary modeling scenarios, we consider the usage of backup heating systems, particularly in the case of summer-sized systems that are not sized to meet heating loads in the winter. The possible configurations of a backup heating system are typically constrained by the nature of the existing heating system and the type and size of heat pumps installed. We define our configurations based on those used in NREL's End-Use Savings Shapes (EUSS) project (National Renewable Energy Laboratory, 2022) as detailed below.

Configuration 1: Ducted home w/ existing backup ("hybrid")

For electrified sub-archetypes where the corresponding baseline sub-archetype has an existing ducted system, we assume the home will have installed a ducted heat pump downstream of the existing furnace or boiler that will serve as backup. The existing system may be fueled by gas, fuel oil, electricity, or such other fuels as wood or propane. In this case, the heat pump and the existing system cannot run at the same time. Installers often define a switchover temperature, $T_{switchover}$ below which the heat pump becomes relatively inefficient and has reduced capacity, where the heat pump is deactivated and the backup system meets the entire load. We define $T_{switchover}$ as 41 °F (5 °C) in summer-sized systems, in line with NREL's assumption for an existing backup system in the EUSS study. Although true for only a small portion of homes in New England, the existing system may be electric resistance.

Configuration 2: Ductless home w/ existing backup ("hybrid")

For archetypes where the existing heating system is ductless, such as those with water-based heating distribution systems, the heat pump and existing system generally will not interfere with one another and can run simultaneously. In this case, we assume sensors and controls have been installed such that, when the heat pump is unable to meet the heating load, the backup system runs to make up the difference between the heating load and the heat pump's capacity. This is likely to be necessary for summer-sized systems during the winter.

Configuration 2a: Ductless or ducted home w/ electric backup

Although only considered as a sensitivity case in this study, our model includes logic to support electric resistance backup heating, which may be used in households that desire to fully electrify and avoid using an existing system that may not already be electric. In this case, we assume the electric resistance coils have been installed downstream of the heat pump in a ducted system or separate from the existing system in a ductless system (e.g., by installing electric baseboard heating). The heat pump and backup system can run simultaneously as in Configuration 2. We treat the electric resistance backup as having a temperature-invariant efficiency of 100%.

2.1.3. Step 3: Aggregating to regional loads

For each archetype, a weight W is applied, equal to the number of homes the archetype represents in the residential stock. Additionally, each archetype in a given zone z has the same weight. We determine the overall number of homes represented by a given archetype by dividing the projected number of homes H_z in the zone by the number of archetypes in the zone, A_z:

$$W_z = H_z / A_z \tag{5}$$

For each archetype in this analysis, there is a single baseline sub-archetype and four electrified sub-archetypes considered, each with its own weight. Let W_u correspond to the weight of a sub-archetype with a given upgrade package in the set of possible upgrade packages U. One such u is the baseline home b, represented by weight W_b. The electrified sub-archetypes correspond to the remaining weights W_u:

1. W_s: Summer-sized heat pump, no envelope upgrades

2. W_{se}: Summer-sized heat pump, with envelope upgrades

3. W_w: Winter-sized heat pump, no envelope upgrades

4. W_{we}: Winter-sized heat pump, with envelope upgrades

Let a given archetype in zone z be archetype i, which is in the set of all archetypes in zone z, I_z . For a given archetype i, the sum of the weights of all its sub-archetypes is equal to the weight of the archetype, which is equal to the shared weight of all the archetypes in the zone:

$$W_i = \sum_u W_{i,u} = W_{i,b} + W_{i,s} + W_{i,se} + W_{i,w} + W_{i,we} = W_z \quad \forall\, i \in I_z \tag{6}$$

The weights for the sub-archetypes can be altered for any given archetype to reflect the level of heat pump deployment and mixing of sizing methods in the portion of the stock represented by the archetype. The profiles for each sub-archetype consist of the heating-and-cooling-related and all other demands. The hourly profiles for each fuel type f for zone z are equal to the summation of the profiles for all sub-archetypes in the zone multiplied by their respective weights. If $L_{f,i,u,h}$ is the demand for fuel f for archetype i with upgrade package u in hour h, then the hourly demand for fuel f in zone z is:

$$\sum_{i=1}^{n} W_{i,b}L_{f,i,b,h} + W_{i,s}L_{f,i,s,h} + W_{i,se}L_{f,i,se,h} + W_{i,w}L_{f,i,w,h} + W_{i,we}L_{f,i,we,h} = L_{f,h} \tag{7}$$

2.2. Parameterization of case study for New England in 2050

2.2.1. Geographic scope & topology

In order to determine demand impacts at a higher spatial resolution than the state level, we define 17 load zones as shown in Figure 6. The zones consist of contiguous groupings of counties with roughly equivalent populations (between 600 thousand to 1.6 million people) and were selected to balance the geographic granularity with the computational intensity of simulating greater numbers of archetypes.

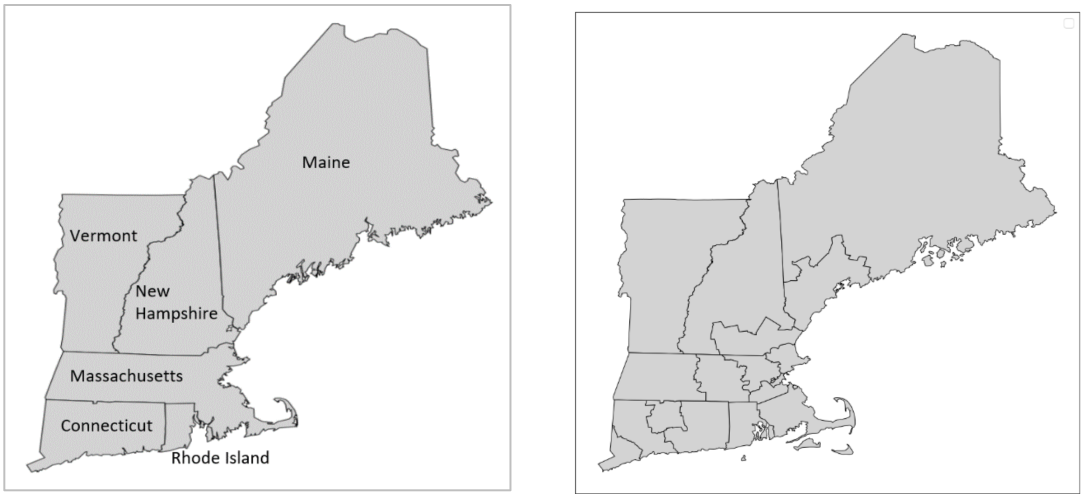

Figure 6. Map of states in New England and map of the load zones considered.

Increasing the number of archetypes results in smoothing of the hourly load profile and convergence to a stable result (E. Wilson et al., 2022). We derive load profiles for each of the zones by simulating approximately 400 archetypes for each zone, a number supported by the literature as being suitable for balancing granularity and computation time in ResStock (Deetjen et al., 2021).

2.2.2. Electrification scenarios

For our analysis of 2050, we include five electrification scenarios:

- A Reference scenario (RF)
- A Medium Electrification scenario (ME)
- A High Electrification scenario (HE)
- Medium and High electrification scenarios that include high deployment of envelope improvements (MX and HX)

We base the ME and HE scenarios on the Massachusetts Clean Energy and Climate Plan (CECP) for 2050, with our Medium Electrification scenarios corresponding to the CECP "Hybrid" scenario and the High Electrification scenarios corresponding to the CECP "High Electrification" scenario (Massachusetts Executive Office of Energy and Environmental Affairs, 2022). The CECP adoption projections include separate adoption rates for systems of different sizes and are listed in units of heating systems. On advice from the Massachusetts Executive Office of Energy & Environmental Affairs, we assume the number of homes that have adopted heat pumps is equal to the number of heat pumps in the overall heating stock. The CECP scenarios do not include projections for adoptions of envelope improvement for 2050, hence, for our envelope upgrade scenarios MX and HX, we assume that 70% of all electrified homes receive envelope upgrades. In our modeling, we assume all regions have levels of adoption in line with the CECP scenarios. We also assume the heat pump deployment scenarios are such that every archetype receives the same proportions of upgrade packages.

Our reference scenario is taken from NREL's Electrification Futures study's "High Electrification – Moderate Technology Advancement" scenario (U.S. Department of Energy Office of Scientific and Technical Information, 2022). Similar to the CECP, it presents projections in terms of heating system stock numbers; however, it does not include information on sizing. As our most conservative case, we assume heat pumps deployed in this scenario are summer-sized and that no envelope upgrades are applied. Figure 7 below shows the scenario definitions graphically, and Table 2 in a table.

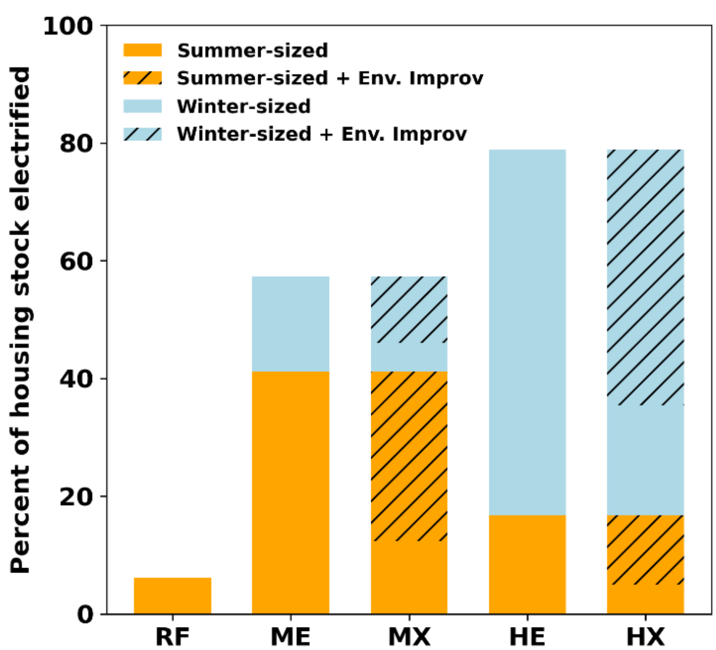

Figure 7. Visual description of future electrification scenarios.

Table 2. Tabular description of future electrification scenarios. Units in percent.

	RF	ME	MX	HE	HX
Summer-sized	6.2	41.2	12.4	16.8	5
Summer-sized + Env. Improv	0	0	28.8	0	11.8
Winter-sized	0	16.1	4.8	62.1	18.6
Winter-sized + Env. Improv	0	0	11.3	0	43.4

For a small number of archetypes in our projected 2050 stock, the baseline sub-archetype already has a heat pump modeled in ResStock. We assume these homes contribute to the projections of adoption and lump them in with "summer-sized" homes. These infrequent instances have electric resistance backup by default (similar to the aforementioned backup system Configuration 2a).

2.2.3. Weather scenarios

Capturing the effect of interannual weather variation on building energy demand requires a diverse array of annual hourly weather data in order to properly characterize the distribution and extremes of potential year-to-year demand outcomes. We use 20 years of historical weather data, which we refer to as *weather years*, as the basis for weather patterns in our demand analysis, adapting it for climate change impacts come 2050 as described below.

2.2.3.1. Weather pattern data

Hourly weather data is a key input to the bottom-up method. We collect hourly actual meteorological year (AMY) data for 2001-2020 in 44 locations across New England corresponding to the weather stations in the DOE's TMY3 dataset, shown in Figure 8. Although the model can support higher levels of spatial granularity, we are limited to these locations because our heat pump sizing method requires TMY data. Each archetype is assigned the weather data closest to the county in which the archetype lies. We source our TMY data from the DOE TMY3 dataset (Wilcox & Marion, 2008). Our AMY data was provided by OikoLab, which furnishes an API for more efficiently accessing large amounts of weather reanalysis data produced by the ERA5 project (OikoLab, 2023). The ERA5 data is also openly available on the ERA project website (Copernicus Climate Change Service (C3S), 2017).

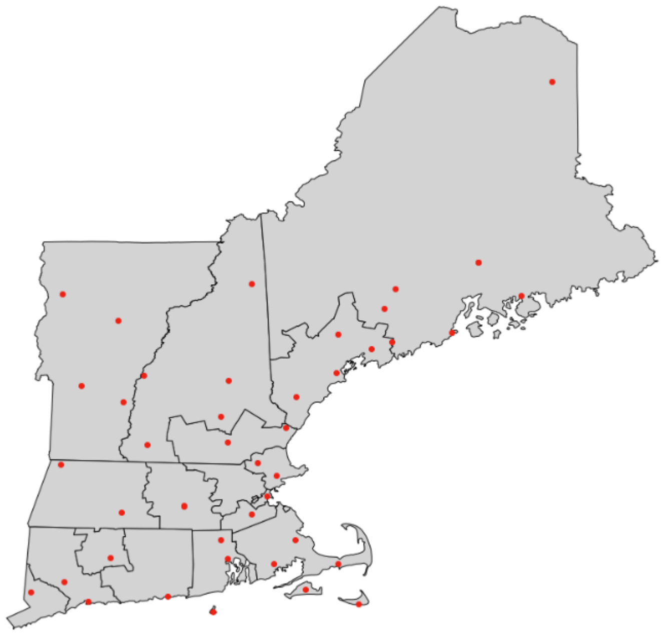

Figure 8. Weather data locations layered over the load zones.

2.2.3.2. Modeling of the effects of climate change

The 2050 time horizon of our analysis necessitates consideration of climate change effects on demand patterns. Increases in temperatures and changes in other meteorological conditions will likely affect demand (Dirks et al., 2015; van Ruijven et al., 2019). Building energy models like the EnergyPlus model underlying ResStock require several specific weather variables at hourly resolution. Climate models generally do not produce predictions at hourly resolution for these variables, an issue that is broadly recognized among researchers (Craig et al., 2022), instead providing predictions at daily or monthly resolution.

The "morphing method," first introduced in Belcher et al. (2005), is a particularly common method for overcoming this disconnect in the literature, combining hourly historical weather data with monthly climate models to produce realistic weather patterns that reflect the long-run effects of climate change (Jentsch et al., 2013; Machard et al., 2020). The morphing method offsets and scales the hourly values within each month to reflect the monthly average changes projected by the climate model. It also manipulates the hourly values to reflect changes in the monthly maxima and minima when they are available. We use the morphing method to apply the effects of climate change to our baseline 2001-2020 weather data. As described in Belcher et. al

(2005), the selection of the morphing operation depends on the nature and units of the underlying variable. For example, it is appropriate to "shift" mean temperatures because they are in absolute units of C, but relative humidity, which is provided in percentages and cannot go below zero, is more amenable to a "scale" operation. We select the CESM2 model (Danabasoglu et al., 2020) as the basis for the morphing because of its popularity, because its data is accessible through the CMIP6 project (O'Neill et al., 2016), and because it provides the necessary variables as outputs. We select the SSP3-70 shared socio-economic pathway greenhouse gas emissions scenario as an approximation of medium-to-high warming. In determining the long-run changes from the climate model, we compare the average outputs of the model between the periods 2015-2023 and 2046-2054. As opposed to simply comparing the outputs for 2020 to outputs for 2050, taking averages of multi-year periods smooths out any changes that may be the result of the interannual weather variation simulated in CESM2 rather than long-run climatic changes. We note that because our baseline weather data forced through the morphing method is taken from any year 2001-2020, we inherently assume no differences among the 2001-2020 weather years due to the effects of climate change. A variable required by EnergyPlus but not provided in the CESM2 model is the dew point temperature. We approximate it from the morphed dry bulb temperature and relative humidity values using the MetPy package in Python (May et al., 2022).

2.2.4. Population projections

Our analysis calls for projections of the number of homes in 2050. Generally, state-level projections for home growth through 2050 are unavailable. We assume the number of homes grows proportionally to households or population, depending on data availability. Massachusetts provides household count projections as part of its Decarbonization Roadmap (Commonwealth of Massachusetts, 2020). For other states, we generally source state-level population growth projections from state agencies (Connecticut Data Collaborative, n.d.; New Hampshire Department of Business and Economic Affairs, 2022; University of Virginia Weldon Cooper Center, 2018). In some states, projections only extend to 2040. In these cases, we linearly extrapolate the growth through 2050. Depending on the zone, each archetype represents between 600 and 2,000 homes.

2.2.5. Future building stock

The input parameters of ResStock include housing stock data that is presented in the form of probability distributions for a range of various interdependent building characteristics. We alter the default ResStock distributions to approximate the projected housing stock for 2050. We generalize the projected housing stock changes in Massachusetts, described in the Building Sector Report of the Massachusetts 2050 Decarbonization Roadmap Study (Commonwealth of Massachusetts, 2020), to the entirety of New England. When normalized for floor area, the Roadmap projects that the cohort of residential buildings constructed after the present day will be 23% of the stock in 2050. We modify the ResStock probability distributions to reflect this growth by proportionally increasing the likelihood that the ResStock model samples an archetype of 2010s vintage, the most recent vintage available in ResStock. This implicitly increases the proportions of homes in our 2050 baseline stock that have newer construction characteristics, such as high-quality insulation. The proportions of older vintages in the remainder of the stock are assumed unchanged. In addition to overall stock turnover, we also incorporate projected changes in building type – for example, the Roadmap projects increasing rates of construction for large multifamily buildings in the coming decades.

2.2.6. Modeling present-day demand

In addition to the reference case, it is useful to have a current baseline against which to compare the hourly demands of the future scenarios. We refer to this case as the “present-day” case. Although historical aggregate demands such as annual demands are available for the residential sector, residential hourly demands generally are not. Hence, we attempt to emulate these demands using the same workflow as the electrification scenarios. Similar to the future scenarios, we simulate 400 archetypes per zone, however, we use ResStock’s default housing dataset representative of the 2018 stock. We use weather data for 2001-2020 without any climate change adjustments applied. We determine our archetype weights using home count data for 2020. In this data, there is no modeling of electrification impacts. Similar to the demand modeling for 2050, where the 2001-2020 weather data is used to represent individual possible weather pattern realizations that are then adjusted for climate change, the present-day demand data can be seen as representative of demands for the 2020 baseline under a portfolio of 2001-

2020 weather patterns. Implicitly, these results assume there are no climate change effects that would significantly impact the weather patterns between 2001-2020.

2.3. Results

2.3.1. Implications of electrification for peak demand

Peak annual electricity demand (i.e., the highest hourly demand in a given year) is an important metric to planners, primarily because it signals how much power infrastructure and other energy resources will be needed on the system. In addition to peak magnitude, the timing of the peak is an important consideration for reliability and safety reasons and because certain electricity resources (such as wind and solar) vary in their output from season to season. We quantify the seasonal peak values across New England for all 20 weather years in the violin plot shown in Figure 9 below. The greater of the two seasonal peak values is the annual peak.

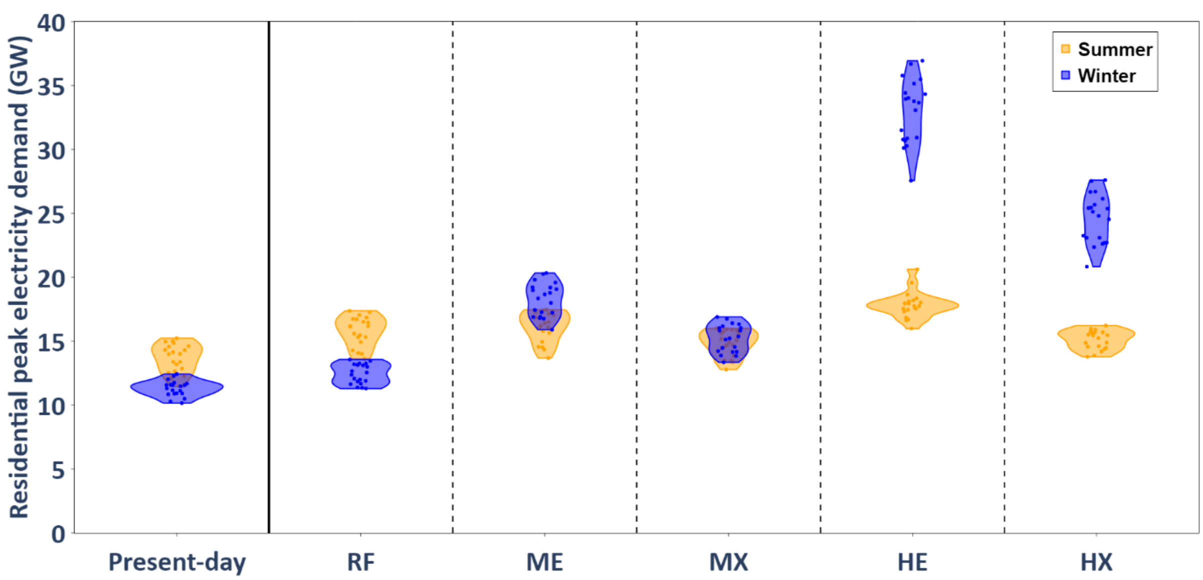

Figure 9. Summer and winter peak demands for the residential sector in 2050 under different electrification scenarios. Each violin contains demand data simulated for 20 weather years. The width of plots increases where the density of data is higher, and the height indicates the range of the data.

We find that peak electricity demands increase with higher amounts of electrification. The reference scenario RF results in a small average peak increase of 2.1 GW across the weather years, while ME and HE result in increasingly higher peak increases of 4.7 and 19.3 GW respectively. Envelope improvements are shown to cause significant decreases in electricity demand, by an average of 8.4 GW for HX compared to HE and 2.6 GW for MX compared to ME. Under the high electrification levels of HE and HX, peak values for the residential sector alone reach magnitudes similar to New England's recent historical economy-wide peaks of 24.4-26.0 GW.

The results also reveal that electrification can alter the seasonal timing of peak load. While the residential sector's average summer peak in the present-day scenario currently exceeds the winter peak by 2.4 GW, the residential winter peak exceeds the summer peak by an average of 0.4, 2.1, 9.5, and 15.2 GW under the MX, ME, HX, and HE scenarios, respectively. New England's system-wide summer peak currently exceeds the winter peak by an average of 5.4 GW (ISO New England, 2023). Thus, HE and HX can drive New England into a winter-peaking system due to the effects of residential electrification alone.

In addition to peak load magnitude and timing, the duration of peak load is a key metric to determine what kinds of supply-side resources are necessary to maintain grid reliability during peak demand events. Figure 10 below depicts peak load duration under the future scenarios, defined as the instances for which the load is continuously above 80% of the magnitude in the peak hour.

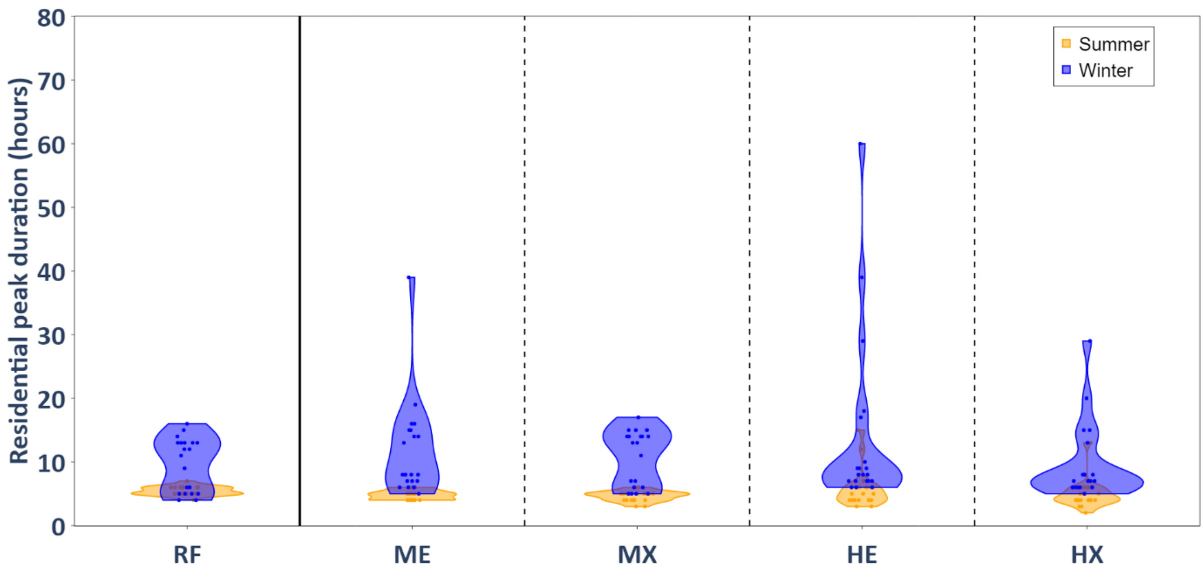

Figure 10. Durations of peak load event for the highest peak load in winter and summer for each electrification scenario.

For certain weather years under certain electrification scenarios, the peak event can stretch into multiple days, especially in the winter. This is particularly the case when electrification is implemented in the absence of envelope improvements. Under medium electrification, envelope improvements can eliminate the possibility of multi-day peak events, but under high electrification, they are still possible, although shorter and less frequent. All instances of winter peak across the scenarios are longer than 4 hours, suggesting there is a need for a firm resource that can supply electricity for a longer duration than short-term lithium-ion battery storage.

2.3.2. Peak sharpness

The frequency and intensity of high-load events is an important metric for evaluating the economics of supply-side capital investment needed to meet potentially infrequent peaks in load. Figure 11 shows the "load duration curves," where the load for each hour is sorted in descending order, for all 20 weather years in each of the future scenarios.

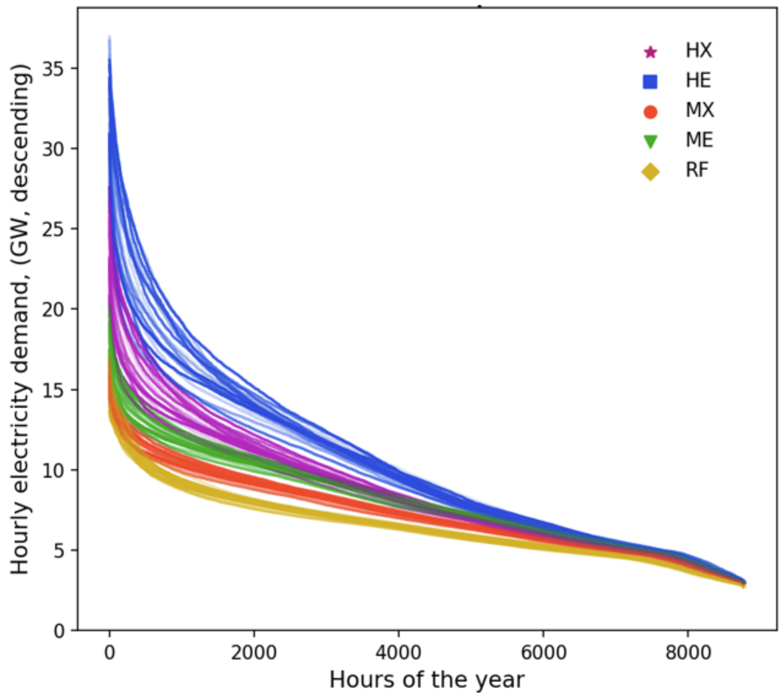

Figure 11. Load duration curves for each electrification scenario.

To evaluate the implications of electrification for capacity utilization, we calculate the average difference between the peak annual load and the 99th percentile load across the 20 weather years for each electrification scenario, which we refer to as “peak sharpness”, corresponding to the leftmost edge of the load duration curve. Values are shown in Table 3.

Table 3. Difference between peak load and 99th percentile hourly load on average across the weather years for each electrification scenario.

Scenario	Peak sharpness (GW)
RF	2.24
ME	2.86
MX	2.30
HE	6.76
HX	4.92
Present-Day	1.95

The results reveal that electrification increases the magnitude of peak relative to hourly loads across the rest of the year. This is especially the case for scenarios HE and HX, which have peak sharpness values notably higher than the other scenarios. This indicates that at higher electrification levels without any demand-side intervention, more supply-side power resources may have to be kept online, but will only be used for a small fraction of the year. This finding is consistent with Waite & Modi (2020), who find that high electrification levels will result in decreased load factors (i.e., the actual total demand divided by the maximum total demand possible in a year), especially in colder regions of the United States.

2.3.3. Spatial distribution of demand changes

Evaluating how electrification impacts power demand in different regions is useful for determining where more power infrastructure investment may be necessary, but is also useful for identifying locations in which the local cost burden of capital investment to meet changes in load may be disproportionately high. As an example, Figure 12 shows the average load increases for each of the 17 load zones under the HX scenario.

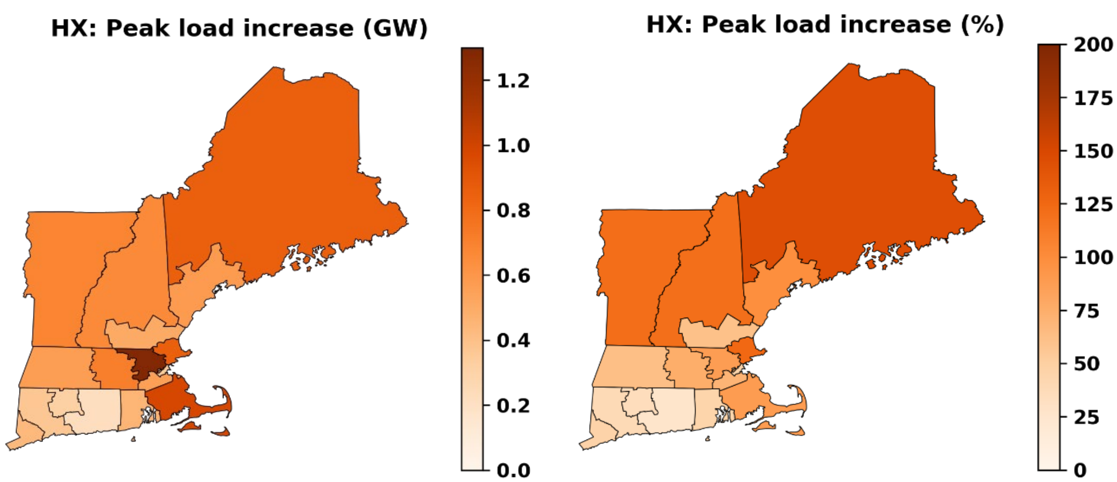

Figure 12. Peak load increase for the 17 load zones under the HX scenario. Percent increase is normalized to the simulated present-day loads and averaged across the 20 weather years.

The absolute load increase is heterogeneously distributed, with the largest increases occurring in the most populated load zones (e.g., Middlesex County in Massachusetts) and the coldest regions, such as northern Maine. However, when normalized relative to the present day, peak load increases are generally higher in the rural, northern regions of New England, approaching

150% increases. This result suggests that greater local power infrastructure investment will be needed to meet the large increase in load, for example via expansion of distribution network capacity. Because these costs are passed through to ratepayers via tariffs, residents of these areas will likely experience relatively higher cost impacts on their electricity bills.

2.3.4. Sensitivity to electric resistance backup

The primary analysis assumes that all homes with 'summer-sized" heat pumps have the heat pump coupled with the home's pre-existing heating system (typically fossil, in a hybrid configuration). However, it is also possible that these households will instead adopt electric resistance systems as their backup systems, for example, when their existing system eventually breaks or because they wish to leave the gas system. Electric resistance backup is inefficient in comparison to heat pumps. We ran simulations to evaluate what the peak demand impacts would be if households with hybrid systems instead used electric resistance backup, with results shown in Figure 13.

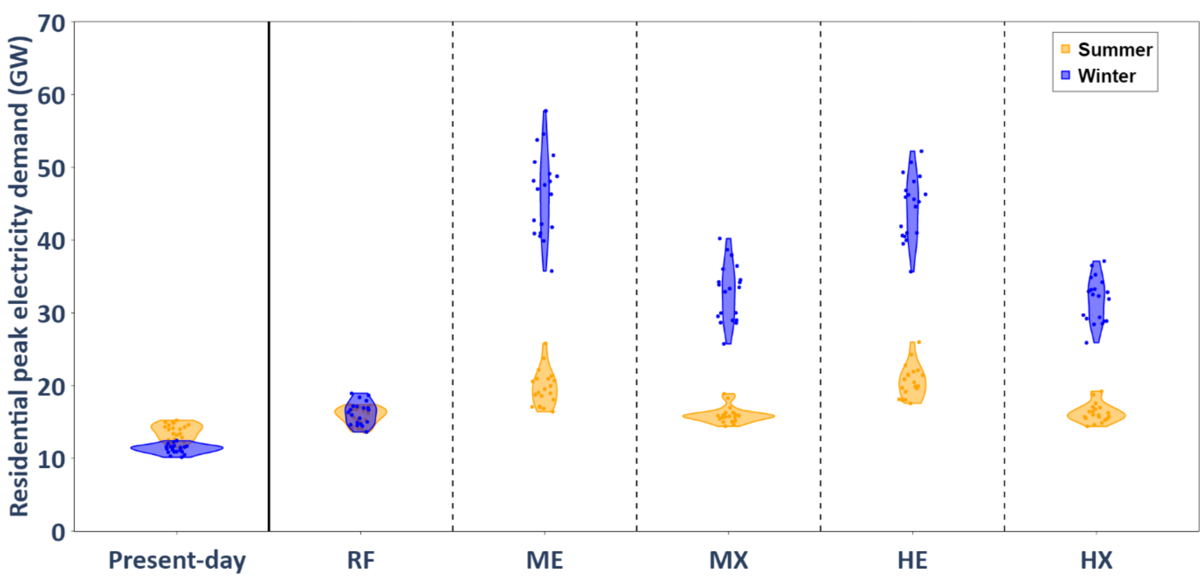

Figure 13. Peak increases when "summer-sized" systems have electric resistance backup.

Each of the adverse demand impacts becomes more drastic if we assume a high deployment of electric resistance backup. Relative to the original 2050 scenarios, peak loads unilaterally increase. A particularly striking result is that the scenarios that include lower deployment of heat pumps overall, but more summer-sized heat pumps, now result in higher average load than their counterparts. Scenario ME now has the highest median peak of 47.3 GW, 28% higher than even the highest peak of 36.9 GW presented under the HE scenario in the base case. The sensitivity of peak load to interannual weather variation also increases drastically across the scenarios, posing higher future demand uncertainty for system planners.

If we assume some substantial amount of homes with hybrid systems will eventually replace their backup with electric resistance, the increase in peak loads poses concerns for the long-term implications of prioritizing the deep deployment of summer-sized heat pumps in the near term. In this case, more conservative electrification pathways that result in the earlier deployment of smaller heat pumps may actually result in higher peak increases in the long term.

2.3.5. Implications for total demand for power and gas

Beyond hourly metrics, quantifying total annual demand for power and gas can inform policymakers about the likely relative usage of the power and gas systems. Figure 14 shows annual power demand, gas demand, and their combined demand for each of the future scenarios as well as the present day.

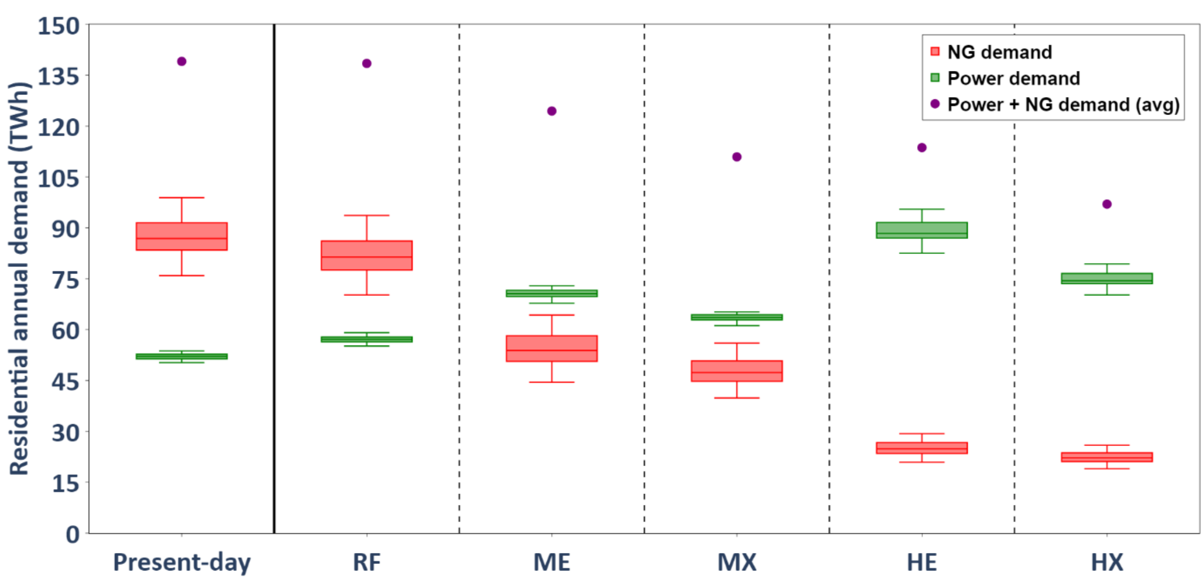

Figure 14. Annual demands for power and gas across the 20 years for each electrification scenario and the present-day scenario. The height of the box plots captures the amount of interannual variation in demand for each fuel.

With increasing amounts of heating electrification in the housing stock, Figure 14 shows that annual residential NG consumption declines while electricity consumption increases. For HE and ME scenarios, electricity demand increases over the present day by an average of 36.7 TWh (70%) and 18.5 TWh (35%) across all weather years. The impact of these electrification scenarios on NG consumption is a reduction of 62.1 TWh (71%) and 33.1 TWh (38%), respectively. Due to the higher efficiency of heat pumps compared to the existing heating stock, the total final energy demand also declines with increasing electrification, by an average of 18% between the present-day and HE scenarios. At increasing levels of electrification, interannual variation in demand decreases for NG but increases for electricity because greater amounts of the service demand for heating are being met by electricity. Deploying envelope improvements in parallel with heat pumps reduces the consumption of electricity by 16% between HX and HE scenarios and by 10% between MX and ME scenarios. Envelope improvements also induce gas demand savings of 11% and 12%, respectively.

2.4. Discussion of demand-side results and recommendations

The demand-side analysis reaches several findings with implications for New England's future energy systems under deep electrification. First, we find that electrification has the potential to increase peak electricity demand that shifts from occurring in the summer, when the cooling demand is highest, to occurring in the winter, when the heating demand is highest. Under a prospective scenario for high electrification, peak demand in the residential sector alone can rival that of the current system-wide peak, indicating large amounts of power infrastructure investment in generation, transmission, and distribution capacity will likely be necessary to meet the increase in load. While theoretically this load increase could be met with large deployment of variable renewables such as offshore wind, which has high potential in New England especially in winter (Massachusetts Department of Energy Resources, 2019), the high "sharpness" of these peaks indicates that certain supply-side power resources retained to meet peak may be underutilized. Such underutilization could result in high capital cost burdens transferred to ratepayers relative to the energy supplied. Prior studies that have encountered similar results suggest that this characteristic favors investment in hybrid systems that can maintain levels of capacity utilization similar to the present-day, as in our ME and MX scenarios (Waite & Modi, 2020). However, the economic analysis must be balanced against the societal costs of continued gas usage in the residential sector, a tradeoff which is understudied in the literature and outside the scope of the quantitative portion of this thesis. Our evaluation of envelope improvements reveal that they can significantly reduce peak and overall electricity demand under deep electrification scenarios and could be essential to reducing wasteful investments in supply-side capacity. While the literature indicates traditional energy efficiency improvements such as envelope improvements often result in demand savings below their technical potential due to behavioral "rebound effects" (Sorrell et al., 2009), evidence from government programs demonstrates their cost-effectiveness (Tonn et al., 2018). Our findings suggest current weatherization efforts should be enhanced under deep electrification.

The finding that the highest peak events are relatively infrequent suggests the importance of leveraging demand-side measures that can increase capacity utilization by reducing the need to keep power capacity on standby for isolated peak events. The modeling framework presented in this paper inherently presumes unchanging demand behavior, but policies that can drive behavioral change, such as time-varying rate structures and demand response programs, may shift peak and reduce the needed supply-side investment. However, the effectiveness of these policies may be limited, for example due to behavioral barriers that result in lower-than-expected demand reductions (Kim & Shcherbakova, 2011). Distributed energy resources including thermal energy storage and batteries may also mitigate peak impact but face similar limitations. Additionally, demand management implementations pose potential equity issues, for example, due to cross-subsidization of wealthier customers by poorer customers who are less able to shift their consumption patterns or invest in distributed energy resources (Ansarin et al., 2022). Our results also indicate that in extreme cases at high electrification levels, demand peaks may stretch into multi-day periods well beyond the expected duration of most demand-side management measures. These events become particularly problematic in the context of future energy systems that rely primarily on VREs. While long-duration energy storage (LDES) may serve to fulfill some of this demand in place of current fossil generators, evidence suggests that cold climates will likely need some other form of firm supply-side capacity to meet demand in these circumstances, given currently-known LDES technologies (Sepulveda et al., 2021). Planners should rigorously evaluate the role of demand management and novel supply-side technologies in order to reduce the need for potentially GHG-intensive flexible generation in a system with deeply electrified heat.

Additionally, the finding that medium electrification pathways like ME and MX can results in higher peak demands with the usage of electric resistance backup is important for policymakers to recognize. Commonly suggested implementations include summer-sized heat pumps that are supplemented by the fossil system already existing in the home (Waite & Modi, 2020), but when the existing system eventually breaks and must be replaced (typical furnace lifetimes are on the order of 15-20 years (Carrier, Inc., n.d.)), we suggest that homeowners would be likely to invest in inexpensive electric resistance heating, rather than replacing their recently-installed heat pump with a larger one or continuing to pay for two separate heating systems. Proponents of hybrid electrification often advocate for it on the basis of a reduced need for supply-side investment in the power sector, however, this may only be the case in the near term. The gradual replacement of existing fossil-fired backup systems with electric resistance could lead to greater peak increases in the long run, suggesting that prioritizing whole-home electrification via "winter-sized" heat pumps from the start may mitigate worse grid impacts by mid-century.

Our results illustrate that in New England, the increase in peak load is likely to be heterogeneously distributed, with greater relative increases occurring in the more rural northern regions. This will likely lead to higher adverse cost impacts for residents in these areas on a per-capita business. Further exacerbating the issue in the states of Maine and Vermont is that their populations are both lower-income and older on average than other regions of New England (*U.S. Census Bureau QuickFacts*, 2022), meaning these cost impacts could be regressive. Also worth consideration, and supported by prior work focused on Massachusetts, is that the cost of heat pumps themselves can result in negative returns on investment given current electricity prices (McBride, 2022). Policymakers should consider the distributive impacts of electrification and structure incentives and cost allocation methods to reduce inequitable cost burdens on the most impacted communities.

Last, and more relevant to the remainder of this paper, is what indications the annual demand results give for the future overall demand for power and gas. Even modest levels of electrification will diminish gas demand by 40%, with higher levels of electrification resulting in a further reduction of 70% relative to the present day. This result indicates that worries about the future viability of the status quo gas utility system are well-founded. However, it is notable that the HE scenario only reduces gas consumption to 30% of its value in the present-day simulations. This result suggests that there will be residual gas demand in the residential sector which must be considered on the path to decarbonization or, alternatively, that regional policymakers should consider even higher degrees of electrification than those evaluated in this analysis, in order to further reduce gas consumption.

3. Comparative analysis of regulatory approaches to key issues for the future of gas

Among other insights, the demand analysis presented in the first section of this thesis supports a key understanding: electrifying residential heat would diminish the demand for gas in New England. More broadly, the call for decarbonization will impact and potentially lower gas demand in all sectors that gas utilities currently serve. This conclusion is bolstered by plans among state policymakers to decarbonize other sectors with high gas demand, including the commercial and industrial sectors (Massachusetts Executive Office of Energy and Environmental Affairs, 2022). In combination, the prospect of electrification and the need to decarbonize gas-fueled end-uses threaten gas utilities as they currently exist, necessitating policy and regulation to ensure the future role of gas distribution systems aligns with expected future pathways.

This section of the thesis will discuss current regulatory approaches to the future of gas in Massachusetts, and where possible, how they compare to the approaches of other states grappling with how to regulate the future role of gas infrastructure, namely California and New York. These states are among the earliest and most populous to undertake regulatory proceedings examining the future of gas utilities in light of legislative decarbonization objectives, and offer key comparative insights for Massachusetts' future regulation and policymaking. Bringing the comparisons into further relief is that, in these other jurisdictions, the public utilities commissions must effectuate similar decarbonization policies to that of Massachusetts. California's own Global Warming Solutions Act calls for a 40% reduction in emissions relative to 1990 levels by 2030 (California Global Warming Solutions Act of 2006, 2006), with a 2022 plan by the California Air Resources Board setting a further target of an 80% reduction by 2050 (Lopez, 2022). New York's Climate Leadership and Community Protection Act establishes an emissions target of 85% below 1990 levels by 2050 (Climate Leadership and Community Protection Act, 2019).

As gas distribution systems are primarily within the purview of individual states, this analysis will focus primarily on the actions of state utilities commissions and legislatures in regulating intrastate infrastructure, rather than large-scale gas transmission. The findings of the comparative analysis inform recommendations for key regulatory and policy changes in Massachusetts as it navigates the future of gas systems.

3.1. Long-term gas planning processes

The future of the gas system has been of recent interest to Massachusetts regulators and policymakers. While the Global Warming Solutions Act and subsequent jurisprudence mandate the Commonwealth to meet legally-binding emissions objectives, the promulgation of regulations to meet these mandates in different economic subsectors has generally been left up to executive agencies. In its role as the public utilities regulator in Massachusetts, the design and implementation of decarbonization policy in the gas sector is largely delegated to the Massachusetts Department of Public Utilities (DPU). The role of the DPU to regulate gas utilities is codified in state law, which gives the Department *"paramount power to… regulate and control the storage, transportation, and distribution of gas"* (*Pereira v. New England LNG Co., Inc.*, 1973). According to the 2021 "Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy", this responsibility recently includes regulating with respect to the climate goals enshrined in the Global Warming Solutions Act: *"In discharging its responsibilities… the department shall, with respect to itself and the entities it regulates, prioritize safety, security, reliability of service, affordability, equity and reductions in greenhouse gas emissions to meet statewide greenhouse gas emission limits and sublimits established pursuant to chapter 21N."*

In June 2020, the Massachusetts Attorney General's office requested the DPU open an investigation into the future of gas in the Commonwealth *"in light of the Commonwealth's legally binding statewide limit of net-zero greenhouse gas ("GHG") emissions by 2050."* While most of the Attorney General's proposed questions did not explicitly encompass the decommissioning of natural gas assets to comply with decarbonization objectives, several questioned the prudency of continued investment in gas distribution infrastructure under expected declining demand and the continued viability of the natural gas business model

(Massachusetts Attorney General's Office, 2020). The DPU agreed to the request, opening an investigation under docket 20-80.

Despite considering an issue of such importance, DPU 20-80 lacked many of the characteristics one might expect in such a planning and policy-relevant proceeding. The planning process was unilateral in that it was primarily led by the local distribution companies (LDCs, i.e., the gas utilities) themselves, which the DPU ordered to contract with consultants and create individual "Net-Zero Enablement Plans", outlining their business plans in a decarbonized future, and to propose a "Common Regulatory Framework" for how the Department should regulate the LDCs through the transition (Massachusetts Department of Public Utilities, 2020). This invited much criticism from detractors, who contended that it was unreasonable for gas utilities to be expected to develop plans for a transition that may result in their own demise. Notably, the DPU did not run 20-80 as an adjudicatory proceeding and hence did not grant other parties intervenor status, and with it the capacity to cross-examine or conduct discovery on the modeling inputs and methods used by the consultants (Massachusetts Department of Public Utilities, 2022a), which several commenters (primarily environmental organization) noted as atypical compared to other similar long-term planning processes recently before the DPU (Acadia Center et al., 2022). The same commenters lamented that the lack of an adjudicatory component allowed the LDCs to develop faulty plans without being required to reevaluate them in response to commenter feedback, arguing that "*much of the technical feedback provided [by the commenting parties] was regrettably ignored and accordingly, considerable portions of the LDCs' consultants' reports remain technically insolvent, rendering the resultant LDC business plans… inherently flawed*." Regardless, the proceeding stalled in October 2022 pending further action by the Department, with the LDC plans being the primary work product, the content of which will be further discussed in this section of the thesis.

California and New York have initiated their own long-term gas planning proceedings that invite a more rigorous and ongoing assessment of utility plans. In 2020, the California Public Utilities Commission (CPUC), acting on its authority to regulate the gas sector, opened proceeding R.20-01-007 as a vehicle for long-term gas system planning with the expressed intent to *"implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals."* The intent of the CPUC to continue this planning procedure for the foreseeable future is evident; in their most recent order in 20-01-007, they instituted a requirement that each gas utility annually file a report on its planned gas system investments, including stakeholder meetings and presentations (California Public Utilities Commission, 2021). The New York Public Service Commission (PSC) established its own long-term gas system planning proceeding with the apparent intention to continue the proceeding for an extended duration, ordering it to be executed on repeated three-year cycles where utilities are required to submit ongoing plans for the future of their distribution assets (New York Public Service Commission, 2022a). While the PSC ordered extensive stakeholder engagement processes, workshops, and the ability to file comments, they did not allow discovery of LDC documents by intervenors, similar to DPU 20-80. However, they are soliciting an independent consultant to review LDC plans, rather than being contracted directly by the LDCs themselves.

Worth noting is that the policy environment in Massachusetts has undergone recent changes that leave open the possibility of a renewed continuation upon 20-80. On July 21, 2022, the legislature enacted bill H.5060, An Act Driving Clean Energy and Offshore Wind, which, among other climate and energy-related provisions, included statutory changes in response to DPU 20-80. Most notably, the Act required the DPU to run an adjudicatory proceeding before approving any LDC plan filed to DPU 20-80 (An Act Driving Clean Energy And Offshore Wind, 2022). This halted the possibility that the DPU would give formal regulatory backing to the controversial LDC-submitted Net Zero Enablement Plans. Furthermore, the January 2023 inauguration of a new governor previously critical of DPU 20-80 (Shankman, 2022) and the resultant appointment of new DPU commissioners (Wasser, 2023) indicates a renewed iteration of a gas planning proceeding may be likely.

The remaining material in this section will outline the regulatory approaches these jurisdictions have taken to specific issues concerning the future of the gas system, many of which have been considered in the aforementioned gas planning proceedings.

3.2. Gas infrastructure expansion

A key debate surrounding the future of gas centers on whether there is a role for any further spatial expansion of the gas distribution system to new customers in light of state legal obligations to meet emissions reduction objectives. If gas usage is to decline, then it is reasonable to assume expansion of the gas system will require greater scrutiny going forward, perhaps even being halted on account of climate obligations. Each state's government has taken actions that give some indication of how they envision the role of future gas system expansion given the tension with climate mandates.

Through recently instituted rules that apply greater scrutiny to new gas infrastructure projects, CPUC has moved towards restriction of gas pipeline expansion. In a December 2022 decision, the Commission began requiring that a Certificate of Public Convenience and Necessity (CPCN) be issued for all gas projects with costs above $75 million (California Public Utilities Commission, 2021). To be granted the certificate and allowed to construct the project, the utility must pass a review of local environmental impacts and provide an evaluation of any non-pipeline alternatives. The decision was motivated by the CPUC's awareness that long-run declines in gas demand may reduce the necessity for large investments in gas infrastructure, posing a stranded asset risk that must be mitigated by a more rigorous evaluation of proposed projects. Beyond the cost-related concerns, CPUC also recognized that recent movement in the state's climate policy motivated a *"need to review significant investments in gas infrastructure for consistency with California's long-term greenhouse gas emission reduction, air quality, equity, safety and reliability goals."* CPUC has also stemmed the expansion of natural gas infrastructure in proceedings other than 20-01-007. In its building decarbonization proceeding, the Commission became the first in the nation to eliminate subsidies for gas distribution line extensions to new hookups (California Public Utilities Commission, 2022b), citing that they *"are no longer consistent with today's GHG emission reduction goals, the urgent need to reduce gas rates to ensure affordability, and the long term need to minimize future stranded investment"* (California Public Utilities Commission, 2021).

In New York, some measures have been taken by the PSC to explore alternatives to pipeline expansion. In recent rate cases, the PSC ordered all utilities to discontinue certain activities that encourage gas system expansion, including oil-to-gas conversion programs, marketing, and certain rebates (New York Public Service Commission, 2022b). In their aforementioned three-year gas planning cycles beginning in 2022, LDCs will be required to submit a "no-infrastructure option" in their capital investment plans, that describes how they could meet marginal demand without any new physical infrastructure, for example via demand response or "other non-pipeline alternatives" (New York Public Service Commission, 2022a). Furthermore, the PSC ordered LDCs to now quantify the costs of an existing state law that establishes an obligation for LDCs to provide gas line extensions to customers within 100 feet of an existing line at no cost to the customer. They also ordered staff to propose changes to this rule (presumably including its elimination) pending further analysis. For their part, the New York legislature has also recently sought to halt distribution grid expansion. In the most recent 2022-2023 session, the New York Senate passed the NY HEAT Act, which would have repealed the obligation to gas service, ended the 100-foot rule, and prohibited further gas service territory expansion after 2025. However, it did not receive consideration by other branches of government in time to be written into law, and seems unlikely to succeed in later sessions (Kinniburgh, 2023).

In contrast to the CPUC and PSC, the Massachusetts DPU has yet to promulgate any independent decisions to stem pipeline expansion. For example, as recently as December 2022, the Department approved the expansion of a distribution pipeline to the town of Douglas in central Massachusetts (Massachusetts Department of Public Utilities, 2022c). Although the proposed gas throughput of the project is small relative to statewide usage, the argument put forth by the Department in its ruling indicates a broader hesitancy to weigh statewide climate goals against what they view as their obligation to serve new public demand. In particular, the Department argued that *"the state's recent climate acts have neither repealed nor amended [preexisting law] which mandates that the Department review and approve proposals designed to increase the availability, affordability, and feasibility of natural gas service for new customers,"* and therefore there must not be *"a legislative intent in the [Global Warming Solutions Act]'s GHG emissions reduction targets to curtail any expansion of natural gas service, because it is incompatible with the express legislative intent of another statutory provision."* As such, DPU primarily evaluated the project on the basis of its impact on system reliability, cost, and the town's interest and purported benefit in receiving gas service. The broad reasoning put forth by DPU in the decision would rightfully worry stakeholders opposed to gas system expansion.

3.3. Gas infrastructure repair and replacement

In addition to the construction of new pipelines, existing pipeline systems often need repair or replacement to prevent leakage and improve safety and reliability. However, because such maintenance extends the service lives of gas infrastructure, this can be seen as in tension with decarbonization objectives, especially if electrification is to be the desired decarbonization pathway.

Massachusetts' regulatory approach to gas infrastructure repair and replacement has historically been quite permissive. Common among the LDCs' Net-Zero Enablement Plans submitted to DPU 20-80 were recommendations to maintain the current practice of so-called Gas System Enhancement Plans (GSEPs) as established under the Gas Leaks Act. Passed by the Massachusetts legislature in 2014, the Gas Leaks Act sought to facilitate pipeline repairs and replacement in order to improve public safety and reduce leaks in the state's aging distribution infrastructure (An Act Relative to Natural Gas Leaks, 2014). The statute requires utilities to submit annual plans for gas system enhancement and petition for cost recovery outside of their general rate cases, enabling them to both construct the upgrade and begin charging ratepayers to recover the cost within the next year. GSEP has since become a primary vehicle for natural gas infrastructure improvement in the Commonwealth, accounting for 40-60% of LDC capital investments (Massachusetts Attorney General's Office, 2022). If fully implemented for its currently-planned duration, each LDC's upgrade process will take a further 20-25 years as of 2021 (Seavey, 2021). While GSEP has ostensibly been effective in reducing leaks and improving safety, critics argue that LDCs are also using it as a mechanism to lock in their infrastructure and ready the distribution system for a future that will maintain their status quo business model of gas delivery (Seavey, 2022). Evidence shows that LDCs have large discretion over whether to repair or replace a pipe and that they often choose to replace it, increasing the lifetime and cost of the asset which will be recovered from ratepayers (Ackley et al., 2019). State agencies seem to agree with these assessments, noting in comments to 20-80 that *"Present GSEP initiatives rest on the underlying assumptions that… natural gas throughput will remain steady or increase indefinitely into the future"* (Massachusetts Attorney General's Office & Massachusetts Department of Energy Resources, 2022).

However, more recent legislative action has sought to reverse this potential lock-in by forcing consideration of alternatives. In particular, the aforementioned H.5060 added *"advanced leak repair technology"* and *"replacing gas infrastructure with utility-scale non-emitting renewable thermal energy infrastructure"* (i.e., networked geothermal systems) as improvements eligible under the program's cost recovery mechanism. In effect, the legislature mandated that the DPU consider upgrades under GSEP that do not result in wholesale replacement of the pipes and risk gas lock-in or stranded assets. Additionally, H.5060 established a "GSEP working group" to evaluate GSEP's impacts on GHG emissions and stranded asset risks as well as *"opportunities to advance utility-scale renewable thermal energy."*

Similar to Massachusetts, the CPUC administers programs for pipeline repair and replacement. The Natural Gas Leak Abatement program (NGLA) was established by CPUC in 2019 in response to Senate Bill 1371, which required the Commission to take action to reduce leakage across the state's pipeline system (California Public Utilities Commission, 2015). As opposed to the Massachusetts Gas Leaks Act's focus on safety, the statute established emissions reductions as a primary motivation for the program. NGLA requires gas utilities to submit annual leak abatement action plans for Commission review and approval (Natural Gas: Leakage Abatement, 2014). CPUC also runs a pipeline repair program centered on safety improvements, similar to Massachusetts, but the costs can only be recovered after the project is completed, following an "after-the-fact reasonableness review" of costs incurred (California Public Utilities Commission, 2011). In this sense, those repairs not pertaining directly to emissions reductions are under heightened regulatory scrutiny which likely reduces the potential for runaway costs and infrastructural lock-in.

3.4. Targeted electrification and gas as a substitutable service

As regulators grapple with the question of pipeline retirement, so too must they consider the process by which electrification can replace gas service in a coordinated manner. So-called "targeted electrification" relies on the "pruning" of the gas distribution system, by which localities are strategically removed from the gas system and electrified. Electrification proponents often support this method for undertaking electrification on a broad geographic scale (Halbrook, 2021; Prause, 2022). While appealing as a policy, none of the three states in this thesis have yet implemented a targeted electrification program.

Although not necessarily the immediate barrier, one obstacle to targeted electrification is the legal right for existing gas customers to receive continuing gas service, a concept that is generally acknowledged as being embodied in the public utility codes among the three states considered in this thesis (Gundlach et al., 2023; Gundlach & Stein, 2020b; Wallace et al., 2020). This conflict will require ongoing state action to resolve. One body of recommendations calls for legislators to amend the right to gas service for a more generic "right to energy" or by removing the right to gas altogether (Gundlach & Stein, 2020a) enabling regulators to mandate targeted electrification without requiring unanimous customer consent in a given locality. Other suggestions raise the possibility that the legislative passage of net-zero goals implicitly repeals the preexisting right to gas service because the emissions intensity of gas usage directly contravenes GHG reductions goals, therefore fundamentally conflicting with the new legislation (Gundlach & Stein, 2020a), but it is unlikely that such a claim would withstand judicial scrutiny. Still others suggest that a right to gas "service" may not necessarily imply a right to the fuel itself, but rather a right to the services the fuel provides, including heating and cooking (Wallace et al., 2020). In Massachusetts specifically, some observers contend that because statutes call for a *"right of user to gas* or *electricity,"* the services are legally substitutable for one another, although this specific theory has not been tested in a judicial setting with respect to existing gas customers (Gundlach et al., 2023).

None of the utility commissions in the three states have gone so far as to contend any of the above arguments. In any case, regulators in certain states have taken some interest in the idea of pruning the gas system and targeted electrification. The PSC recently identified targeted electrification as a promising solution for replacing segments of leak-prone pipe in New York, but acknowledged the right to gas service as an obstacle, which would require all residents on a branch of the distribution system to consent to their gas service being terminated (New York Public Service Commission, 2022a). The CPUC considers targeted distribution infrastructure retirement as a key component of their ongoing gas planning work, expressing that "*much of the remainder of Track 2 work in [the gas planning] proceeding will develop a process to identify criteria to selectively avoid new distribution line infrastructure and to "prune" existing gas distribution line infrastructure, where feasible and beneficial*" (California Public Utilities Commission, 2021), however, the process is ongoing.

By contrast, DPU has not shown any motion on the idea of targeted electrification. While targeted electrification was one of the pathways considered in the LDCs' consultants' analyses and was included in some individual utility business plans (Eversource Energy, 2022; Liberty

Utilities, 2022), it did not get representation in the LDCs' ultimate combined policy proposal to the Department (Joint LDCs, 2022). Other parties to 20-80 lamented this fact; for example, the Massachusetts Department of Energy Resources contended that *"[The LDCs' proposed Regulatory Framework] fails to identify specific action that would demonstrate the benefits of strategic electrification paired with decommissioning portions of the LDC distribution system,"* recommending that the LDCs be ordered to establish such plans (Massachusetts Department of Energy Resources, 2022). In failing to issue any order subsequent to the LDC proposals in 20-80, DPU remained silent on the matter, a potentially concerning outcome for advocates who see targeted electrification as a necessary step for future pathways with even a modest amount of gas distribution system retirement.

3.5. Renewable natural gas

In part because of the potentially adverse impacts and costs of deep electrification of heating, some proponents favor the usage of alternative means to decarbonize the gas system. Foremost among these are proposals for the usage of renewable natural gas (RNG) such as biomethane and synthetic methane, which in principle could be used as a low-carbon or net-zero drop-in replacement for fossil gas, enabling the continued usage of the gas distribution grid and existing heating systems. This feature often makes RNG a favored "solution" among gas utilities. The viability of widespread RNG deployment is highly debated (for reasons which will be discussed further in the final section of this thesis) and state regulatory schemes and policies in response to this concept are still developing. Regulators have entertained the concept of renewable gas in differing amounts. While the CPUC and PSC have begun to set the boundaries for RNG's future role in the gas system, DPU's future approach is as yet poorly defined.

In the LDC plans that resulted from the 20-80 proceeding, RNG was a significant (or even primary) component of each company's decarbonization portfolio. For example, Eversource expressed that they were *"prioritizing efforts to support the development and procurement of RNG"* because of its ability to "*utilize much of the existing network*" (Eversource Energy, 2022). Liberty Utilities also envisioned replacement of existing gas service with biogas, such that "*Under Liberty's Plan, customers that operate efficient furnaces, boilers, and gas heat pumps will do so with increasing proportions of renewable gas, replacing geologic natural gas consumption and its associated emissions by 2050"* (Liberty Utilities, 2022). Furthermore, the joint LDCs requested that DPU authorize a "Cost of Gas Adjustment Clause" that would enable them to recover marginal costs associated with the procurement and delivery of biogas even if it is not the lowest-cost resource (Joint LDCs, 2022). Given the non-adjudicatory nature of the proceeding, the LDCs did not have to respond to stakeholder contentions on the merits of these plans, including key future technoeconomic and emissions uncertainties of RNG that will be discussed more in the last section of this paper.

Despite the enthusiasm for biogas deployment evinced by the LDC submissions from DPU 20-80, the DPU has not yet ordered or authorized the procurement of biogas by any LDC. As of the time of writing this thesis, a single petition to procure biogas has come before the Department. The DPU explicitly declined to weigh on the merits of RNG's emissions impact, but rather denied the petition on the basis that the project did not contribute to system reliability as claimed (Massachusetts Department of Public Utilities, 2022b). This renders outside interpretation of DPU's stance on the merit and preferred future applications of RNG difficult.

By contrast, CPUC has more concretely outlined the role it envisions for RNG. In response to SB 1440, CPUC initiated an investigation within its existing biogas rulemaking, R.13-02-008, to determine if and how it should order procurement of biogas among California's gas utilities. Following this analysis, in February 2022, CPUC ordered the procurement of a total of 14.6 billion cubic feet of biogas between the utilities *"as soon as possible"* (California Public Utilities Commission, 2022a). The Commission order also envisioned a growing role for the fuel, setting a goal that 12.2 percent of all retail gas sales (relative to 2020 sales) would be biogas by 2030. However, this order for procurement did not necessarily signal RNG as a primary component of CPUC's preferred gas system decarbonization strategy, rather, CPUC has expressed that it envisions a circumscribed role for it: "*even though electrification is our preferred option, we recognize that for now, RNG plays an important role in reducing GHG emissions.*" (California Public Utilities Commission, 2022c). A CPUC staff proposal in the long-term gas planning proceeding furthered this notion by suggesting that the deployment of biogas (and the associated delivery infrastructure) be reserved for the most impactful emissions reductions. In particular, they recommended that pipelines that connect hard-to-electrify uses with biogas supply should be at reduced priority for pipeline decommissioning (California Public Utilities Commission, 2022d). A further ruling in CPUC's building decarbonization proceeding again illustrates the limited role CPUC prescribes for RNG in decarbonization policy and the Commission's affirmative position on gas system phase-out: *"Although we agree… that the use of [carbon-neutral alternative fuels like RNG] is a preferred option over diesel and other 'dirtier' fuels during a transition to full electrification, it is still not the preferred option in the long term over full electrification. Our priority in the long term is to move away from fossil fuels altogether…. This has been consistent and reiterated in several Commission proceedings"* (California Public Utilities Commission, 2022c).

The PSC's plans for the future role of RNG are to be determined, however recent policy activities within the state government give some indication of how the boundaries for the fuel's usage will be defined. The PSC is expected to treat the future role of RNG with some amount of circumspection. This viewpoint is primarily evinced in the judgment of the state's Climate Action Council, which state law designates as the primary guiding body for future regulatory decisions in the decarbonization of New York's energy systems, including those of the PSC (Climate Leadership and Community Protection Act, 2019). In particular, the CAC's final Scoping Report noted that *"the potential in-state availability and resource size of RNG is currently small as compared with current levels of fossil natural gas use."* The Council designated that the "*Development of the [gas system transition] plan should be led by [PSC],"* calling for a *"review of the costs and benefits associated with both the transition to electrification and potential adoption of alternative fuels"*(New York State Climate Action Council, 2022). While precise regulatory decisions are pending further order by the PSC, this guidance suggests they will at least be more skeptical and promote a more refined view of future applications of RNG than DPU has to date.

3.6. Cost allocation

Common among the regulatory battles surrounding the decarbonization of the gas sector is the question of how to pay for it. As previously indicated, gas infrastructure must be fully depreciated in order for the utility to receive a full payback and profit on their investment, the costs of which are traditionally borne by ratepayers who recoup the utility's investment cost through paying rates over a multi-decade time horizon. However, as ratepayers leave the gas system, this source of revenue may diminish before assets can be fully depreciated. Commonly proposed approaches to enable recovery of the full capital cost of distribution grid assets even as the ratepayer population declines include:

- Accelerated depreciation, by which customer rates are increased in the short term in order to pay off the investment more rapidly
- Exit fees that ratepayers are required to pay upon leaving the gas system in order to offset the future loss in rate revenue to gas utilities
- Securitization of the pipeline assets in ratepayer-backed bonds that enable immediate cost recovery, a tactic which has precedent in the abandonment of coal plants, for example the San Juan Generating Station in New Mexico (Storrow, 2022)
- Cross-subsidization of depreciation by electric ratepayers

Other approaches would impart the cost upon entities other than ratepayers, for example by levying a tax among the general population or by simply denying the utility any further recovery of the cost of the capital investment and placing the cost on their shareholders (L. W. Davis & Hausman, 2021). However, these solutions are controversial. Placing depreciation costs on taxpayers induces costs among groups who did not make use of the gas system. Denying the utility cost recovery may reduce investor confidence and also be perceived as unjust, particularly if the investments in stranded pipeline infrastructure were initially overseen or approved by the regulator. A similar, but less drastic option would be to enable cost recovery up to the cost of the asset, disallowing profit only (Brockway, 2021; L. W. Davis & Hausman, 2021).

Among the possible cost allocation mechanisms, few decisions have been made by regulators in any of the identified jurisdictions as far as preferred paths forward. In Massachusetts, discussions around cost allocation have primarily been formulated as part of the LDC proposals to DPU 20-80. In their proposals, LDCs suggested that DPU consider accelerated depreciation to *"align cost recovery of gas distribution costs with the utilization of the distribution system, rather than the useful life of the assets that make up the distribution system,"* as well as exit fees and, in the case of extraordinary amounts of stranded assets, securitization (Joint LDCs, 2022). In New York, the PSC appears partial to accelerated depreciation, having ordered utilities to conduct depreciations studies that assume assets are fully depreciated by 2050 (New York Public Service Commission, 2022a). This would essentially align depreciation timelines with the state's net-zero target; However, the PSC has not identified preferred mechanism by which the accelerated depreciation could be funded. As for California, while CPUC staff have put forward the concern of cost allocation, little has been proposed or considered by the Commission itself on specific cost allocation mechanisms or investigation into them. The aforementioned CPUC staff proposal to the gas planning proceeding primarily emphasizes the need to deflect cost allocation burdens from *"low affordability communities,"* where *"subsidies and/or rate reform may be necessary to avoid imposing increased energy costs on these communities in the short term"* (California Public Utilities Commission, 2022d). Among these jurisdictions, cost allocation mechanisms will likely become more clearly defined as the degree of stranded asset risk becomes better-quantified over time, with the magnitude of the stranded cost presumably increasing where electrification efforts are more aggressive.

3.7. Recommendations for future gas system planning in Massachusetts

These comparisons give indications of the room for opportunity that Massachusetts' policymakers have to improve their approach to planning the future of the Commonwealth's gas system, particularly in light of the little that has been accomplished to date in the DPU's proceedings. We arrive at the following recommendations:

<u>DPU should initiate a continuous long-term gas planning process</u>

Decarbonizing and/or decommissioning the gas sector will be a long-term, sophisticated process that will require continuous planning and implementation by DPU. Merits of their content aside, the LDC plans submitted in DPU 20-80 are not sufficient to guide implementation over the next three decades, and regulators will have to respond to new information and circumstances over time. DPU should implement a long-term, continuous proceeding to facilitate gas system decarbonization, perhaps in a recurring cycle not dissimilar to that initiated by the New York PSC or the DPU's own energy efficiency proceeding (Massachusetts Department of Public Utilities, 2023). Because H.5060 does not mandate a reiteration of DPU 20-80, but rather prohibits the approval of LDC plans without a new adjudicatory proceeding, DPU will have to initiate such a proceeding of its own volition, barring further legislation.

Additionally, because electrification is fundamentally a question of gas system displacement, this process should be coordinated between the gas and electric systems and involve LDCs serving both the gas and electric sectors. This recommendation is supported by a number of other interested parties, for example the recent governor's Commission on Clean Heat (Massachusetts Commission on Clean Heat, 2022) and the Acadia Center (Acadia Center, 2022).

The legislature should reform the right to gas service

Even a moderate amount of electrification and gas system decommissioning will require disconnecting some customers from the gas system who would otherwise rather stay connected. The right to gas service as codified in the Commonwealth's statutes renders any effort to this effect subject to legal challenge. The General Court should consider reforming the obligation to gas service as a more general right to the services that gas provides, whether that be space heating, water heating, cooking, or other end-uses, such that electric technologies can be readily substituted. This would also bring state law into better alignment with the declared goals of the government embodied by the call for electrification in the Clean Energy and Climate Plan for 2050.

DPU should evaluate the future role of RNG with scrutiny

The LDC proposals for RNG procurement as a means of sustaining the gas distribution system must be evaluated in light of the uncertainty and limitations in RNG's technoeconomic potential and emissions impacts. The availability of RNG resources for widespread usage in Massachusetts appears to be very limited. Even the American Gas Foundation, a gas utility trade association and proponent of RNG, estimates that conservatively 580 TWh (2000 TBtu) of RNG will be available nationwide annually come 2040 (American Gas Foundation, 2019) . The scenario with the least residential gas demand presented in the demand-side analysis in the first section of this paper (HX) estimates an average consumption of 22.3 TWh of gas by 2050, a full 4% of that total, needed just for the residential sector in New England alone. This indicates that RNG supply may not be sufficient for decarbonizing a significant amount of present-day residential gas demand.

Second, most indications suggest that RNG will be an expensive resource. For example, a study of RNG potential issued by the New York State Energy Research and Development Authority (NYSERDA), a region similar to Massachusetts, estimates average production costs of $11.29 to $34.56/MMBtu in the year 2040, with higher marginal costs at greater volumes of supply (NYSERDA, 2022). Such high costs weigh against widespread usage of RNG in the likely case that there are more cost-effective alternatives, including electrification. On account of the high costs and likely limited availability of the resource, there is a strong argument that RNG would be better allocated to high-value, "hard-to-decarbonize" end-uses, for example in heavy industry, than it would be in the residential and commercial sectors, where end-uses such as heating have readily-available electric alternatives. This stance is in alignment with that of the CPUC staff proposal mentioned in section 3.5 of this thesis. Other analyses focused on Massachusetts supports this claim; for example, the state 2050 Decarbonization Roadmap finds no allocation of alternative fuels to the residential and commercial sectors even under its "All Options" scenario that allows joint deployment of alternative fuels and electrification to decarbonize the gas system (Acadia Center, 2022).

Additionally, the emissions accounting of RNG is highly debated. Ostensibly, biogas-sourced RNG is carbon-neutral or carbon-negative, for example because it comes from plant-based feedstock that once captured carbon via photosynthesis or because it captures and utilizes what would otherwise be potent methane emissions, e.g. from livestock manure. However, several implementation-related factors render uncertainty to this claim. One notable study claims that, at scale, biogas production will likely be sourced from intentionally-produced feedstocks rather than waste methane, which, in combination with empirically-observed system leakage rates, may actually increase rather than decrease methane emissions (Grubert, 2020). Specifically, Grubert estimates that, when using a 20-year warming potential for methane, RNG becomes more GHG-intensive than fossil gas with just a 5-6.6% leakage rate. A recent analysis of system leakage in the Boston area estimates leakage rates of roughly 2.5%, six times higher than prior Massachusetts government and EPA estimates (Sargent et al., 2021), indicating that deep RNG usage in Massachusetts may be less impactful in generating emissions reductions than is claimed.

DPU and legislators should reform GSEP

As a primary vehicle for present-day gas system capital investment in the Commonwealth, GSEP should be treated with increasing scrutiny. The establishment of the GSEP Working Group and the new legislative requirement that utilities consider non-pipeline alternatives when proposing system repair and replacement are important recent developments to balance the need to maintain system safety and reliability with climate mandates. This author is optimistic about the recommendations the Working Group will put forth to legislators. Said recommendations should be taken seriously and adopted for implementation by default, barring any serious deficiencies identified by DPU. The status quo implementation of GSEP and projected future costs are clearly not in alignment with a future in which the gas system is decommissioned in any meaningful way, risking infrastructure lock-in and more stranded assets.

Policymakers should prioritize equity in determining cost allocation

Most of the methods proposed for recouping the cost of retired gas utility assets result in costs being allocated to ratepayers. While said ratepayers have had the benefit of using the gas system, cost allocation policy should be mindful of the reality that most ratepayers, especially residential customers, did not individually choose to be connected to the gas system. This is especially the case for low-income households, which risk facing disproportionate cost burdens relative to their income in order to fund the depreciation costs associated with the transition. Cost allocation mechanisms should be progressive such that, to the extent costs are allocated to individual households, they are aligned with consumption levels and ability to pay.

DPU should also conduct a retrospective analysis of recent gas utility capital investments that were made with the utility's knowledge of the potential impending phase-out of the gas system and consider disallowing cost recovery in the specific instances for which these investments were demonstrably imprudent. Ratepayers should not have to remunerate capital investments which utilities made in the hopes of preserving a business model that has become apparently less feasible with the passage of time.

3.8. Limitations of comparative recommendations

While many of the recommendations in this thesis are framed with inspiration from their policies, it should be noted that California and New York's recent regulatory approaches to the future of gas are not immune to criticism. Rather, the differences between their regulatory approaches and those of Massachusetts offer examples of actions that the General Court and DPU should consider. Furthermore, these jurisdictions differ along geographic, political, social, and economic dimensions that undoubtedly make some policy and technological approaches more feasible in one region than another. For example, California's warmer climate relative to New England alleviates some of the adverse electricity demand impacts associated with the temperature-dependency of heat pump efficiency, perhaps making it a more attractive option.

This thesis is also relatively agnostic to what are likely nuanced political considerations in the Commonwealth. All policy recommendations should be evaluated relative to their political feasibility; however, it is also worth noting that future gas system planning is relatively uncharted regulatory territory in the US and therefore ripe for innovative policy.

4. References

Acadia Center. (2022, October 14). *Final Comments of Acadia Center to DPU 20-80*. DPU 20-80.

Acadia Center, Conservation Law Foundation, Environmental Defense Fund, Home Energy Efficiency Team, & Sierra Club. (2022, March 28). *Motion for Reconsideration and to Extend the Procedural Order and Provide for Additional Process*. DPU 20-80.

Ackley, B., Fairchild, M., Griffith, S., Phillips, N., & LaRocque. (2019). *Rolling the Dice: Assessment of Gas System Safety in Massachusetts*. Gas Transition Allies. https://www.gastransitionallies.org/safety

American Gas Foundation. (2019). *Renewable Sources Of Natural Gas: Supply And Emissions Reduction Assessment*. https://gasfoundation.org/2019/12/18/renewable-sources-of-natural-gas/

An Act Driving Clean Energy And Offshore Wind, H.5060, General Court of the Commonwealth of Massachusetts, 192nd (2022).

An Act Establishing the Global Warming Solutions Act, General Court of the Commonwealth of Massachusetts, Acts of 2008 (2008).

An Act Relative to Natural Gas Leaks, H.4164, General Court of the Commonwealth of Massachusetts, 188th (2014).

Ansarin, M., Ghiassi-Farrokhfal, Y., Ketter, W., & Collins, J. (2022). A review of equity in electricity tariffs in the renewable energy era. *Renewable and Sustainable Energy Reviews*, *161*, 112333.

Ballarini, I., Corgnati, S. P., & Corrado, V. (2014). Use of reference buildings to assess the energy saving potentials of the residential building stock: The experience of TABULA project. *Energy Policy*, *68*, 273–284. https://doi.org/10.1016/j.enpol.2014.01.027

An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, S.9, General Court of the Commonwealth of Massachusetts, 192nd (2021).

Belcher, S., Hacker, J., & Powell, D. (2005). Constructing design weather data for future climates. *Building Services Engineering Research and Technology*, *26*(1), 49–61. https://doi.org/10.1191/0143624405bt112oa

Bloomfield, H. C., Brayshaw, D. J., Shaffrey, L. C., Coker, P. J., & Thornton, H. E. (2016). Quantifying the increasing sensitivity of power systems to climate variability. *Environmental Research Letters*, *11*(12), 124025. https://doi.org/10.1088/1748-9326/11/12/124025

Brockway, A. M. (2021). *Gas Planning and Reliability in California*. https://doi.org/10.13140/RG.2.2.34271.18082

California Public Utilities Commission. (2011, November 1). *D.14-06-007: Decision Implementing a Safety Enhancement Plan and Approval Process for San Diego Gas & Electric Company and Southern California Gas Company*. Application 11-11-002.

California Public Utilities Commission. (2015, January 15). *Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and*

Facilities to Reduce Natural Gas Leakage Consistent with Senate Bill 1371. Rulemaking 15-01-008.

California Public Utilities Commission. (2021, December 1). *D. 22-12-021: Decision Adopting Gas Infrastructure General Order*. Rulemaking 20-01-007.

California Public Utilities Commission. (2022a, February 25). *D. 22-02-025: Decision Implementing Senate Bill 1440*. Rulemaking 13-02-008.

California Public Utilities Commission. (2022b, September 15). *CPUC Decision Makes California First State in Country to Eliminate Natural Gas Subsidies*. https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-decision-makes-ca-first-state-in-country-to-eliminate-natural-gas-subsidies

California Public Utilities Commission. (2022c, September 20). *D.22-09-026: Phase III Decision Eliminating Gas Line Extension Allowances, Ten-Year Refundable Payment Option, and Fifty Percent Discount Payment Option Under Gas Line Extension Rules*. Rulemaking 19-01-011.

California Public Utilities Commission. (2022d, December 21). *Staff Proposal on Gas Distribution Infrastructure Decommissioning Framework in Support of Climate Goals*. Rulemaking 20-01-007.

Carrier, Inc. (n.d.). *How Long Does A Furnace Last | Furnace Lifespan*. Carrier. Retrieved July 24, 2023, from https://www.carrier.com/residential/en/us/products/furnaces/how-long-does-a-furnaces-last/

Cerezo Davila, C., Reinhart, C. F., & Bemis, J. L. (2016). Modeling Boston: A workflow for the efficient generation and maintenance of urban building energy models from existing geospatial datasets. *Energy*, *117*, 237–250. https://doi.org/10.1016/j.energy.2016.10.057

Commonwealth of Massachusetts. (2020). *Buildings Sector: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study*. Massachusetts Executive Office of Energy and Environmental Affirs. https://www.mass.gov/info-details/ma-decarbonization-roadmap

Connecticut Data Collaborative. (n.d.). *Population Projections by Town*. http://data.ctdata.org/visualization/population-projections-by-town

Copernicus Climate Change Service (C3S). (2017). *ERA5: Fifth generation of ECMWF atmospheric reanalyses of the global climate*. https://cds.climate.copernicus.eu/cdsapp#!/home

Craig, M. T., Wohland, J., Stoop, L. P., Kies, A., Pickering, B., Bloomfield, H. C., Browell, J., De Felice, M., Dent, C. J., Deroubaix, A., Frischmuth, F., Gonzalez, P. L. M., Grochowicz, A., Gruber, K., Härtel, P., Kittel, M., Kotzur, L., Labuhn, I., Lundquist, J. K., … Brayshaw, D. J. (2022). Overcoming the disconnect between energy system and climate modeling. *Joule*, *6*(7), 1405–1417. https://doi.org/10.1016/j.joule.2022.05.010

Danabasoglu, G., Lamarque, J.-F., Bacmeister, J., Bailey, D., DuVivier, A., Edwards, J., Emmons, L., Fasullo, J., Garcia, R., Gettelman, A., & others. (2020). The community earth system model version 2 (CESM2). *Journal of Advances in Modeling Earth Systems*, *12*(2), e2019MS001916.

Davis, L. W., & Hausman, C. (2021). *Who Will Pay for Legacy Utility Costs?* (w28955). National Bureau of Economic Research. https://doi.org/10.3386/w28955

Davis, W. (2022, January 6). *Correctly Sizing Variable-Capacity Heat Pump Equipment*. ACCA HVAC Blog. https://hvac-blog.acca.org/correctly-sizing-variable-capacity-heat-pump-equipment/

Deakin, M., Bloomfield, H., Greenwood, D., Sheehy, S., Walker, S., & Taylor, P. C. (2021). Impacts of heat decarbonization on system adequacy considering increased meteorological sensitivity. *Applied Energy*, *298*, 117261. https://doi.org/10.1016/j.apenergy.2021.117261

Deetjen, T. A., Walsh, L., & Vaishnav, P. (2021). *US residential heat pumps: The private economic potential and its emissions, health, and grid impacts*. *16*(8), 084024. https://doi.org/10.1088/1748-9326/ac10dc

Dirks, J. A., Gorrissen, W. J., Hathaway, J. H., Skorski, D. C., Scott, M. J., Pulsipher, T. C., Huang, M., Liu, Y., & Rice, J. S. (2015). Impacts of climate change on energy consumption and peak demand in buildings: A detailed regional approach. *Energy*, *79*, 20–32.

Eversource Energy. (2022, March 18). *Operating Plan for NSTAR Gas Company and Eversource Gas Company of Massachusetts d/b/a Eversource Energy*. DPU 20-80.

Grubert, E. (2020). At scale, renewable natural gas systems could be climate intensive: The influence of methane feedstock and leakage rates. *Environmental Research Letters*, *15*(8), 084041. https://doi.org/10.1088/1748-9326/ab9335

Gundlach, J., & Stein, E. B. (2020a). Harmonizing States' Energy Utility Regulation Frameworks and Climate Laws: A Case Study of New York. *Energy Law Journal*, *41*, 211–260.

Gundlach, J., & Stein, E. B. (2020b). New York Urgently Needs to Harmonize its Energy Utility Regulation Framework with its New Climate Law. *SSRN Electronic Journal*. https://doi.org/10.2139/ssrn.3623311

Gundlach, J., Zerbe, A., Barth, S., & Weinberger, B. (2023). *The Obligation to Serve in Massachusetts*.

Halbrook, C. (2021, September 21). Lessons Learned (So Far) in Targeted Building Electrification. *Gridworks*. https://gridworks.org/2021/09/lessons-learned-so-far-in-targeted-building-electrification/

International Energy Agency (IEA). (2022a). *Energy Efficiency 2022*. https:/www.iea.org/reports/energy-efficiency-2022

International Energy Agency (IEA). (2022b). *Net Zero by 2050 A Roadmap for the Global Energy Sector*. https://www.iea.org/reports/net-zero-by-2050

ISO New England. (2023). *Energy, Load, and Demand Reports*. https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load

Jentsch, M. F., James, P. A. B., Bourikas, L., & Bahaj, A. S. (2013). Transforming existing weather data for worldwide locations to enable energy and building performance simulation under future climates. *Renewable Energy*, *55*, 514–524. https://doi.org/10.1016/j.renene.2012.12.049

Joint LDCs. (2022, March 18). *The LDCs' Common Regulatory Framework and Overview of Net Zero Enablement Plans*. DPU 20-80.

Joskow, P. L. (2007). Chapter 16 Regulation of Natural Monopoly. In *Handbook of Law and Economics* (Vol. 2, pp. 1227–1348). Elsevier. https://doi.org/10.1016/S1574-0730(07)02016-6

Keskar, A., Galik, C., & Johnson, J. X. (2023). Planning for winter peaking power systems in the United States. *Energy Policy*, *173*, 113376. https://doi.org/10.1016/j.enpol.2022.113376

Kim, J.-H., & Shcherbakova, A. (2011). Common failures of demand response. *Energy*, *36*(2), 873–880.

Kinniburgh, C. (2023, April 18). *Why You're Still Paying for Someone Else's Gas Line*. New York Focus. https://nysfocus.com/2023/04/18/heat-act-100-foot-rule-gas

Langevin, J., Reyna, J. L., Ebrahimigharehbaghi, S., Sandberg, N., Fennell, P., Nägeli, C., Laverge, J., Delghust, M., Mata, É., Van Hove, M., Webster, J., Federico, F., Jakob, M., & Camarasa, C. (2020). Developing a common approach for classifying building stock energy models. *Renewable and Sustainable Energy Reviews*, *133*, 110276. https://doi.org/10.1016/j.rser.2020.110276

Natural gas: Leakage abatement, S.B. 1371, California State Legislature, 2013-2014 session (2014).

Li, J., & Colombier, M. (2009). Managing carbon emissions in China through building energy efficiency. *Journal of Environmental Management*, *90*(8), 2436–2447. https://doi.org/10.1016/j.jenvman.2008.12.015

Liberty Utilities. (2022, March 18). *Initial Net Zero Enablement Plan for Liberty Utilities (New England Natural Gas Company) Corp. D/b/a Liberty*. DPU 20-80.

Lopez, N. (2022, April 28). Lower cost, slower gains: California prepares controversial new climate strategy. *CalMatters*. http://calmatters.org/environment/2022/04/california-climate-change-strategy/

Machard, A., Inard, C., Alessandrini, J.-M., Pele, C., & Ribéron, J. (2020). A Methodology for Assembling Future Weather Files Including Heatwaves for Building Thermal Simulations from the European Coordinated Regional Downscaling Experiment (EURO-CORDEX) Climate Data. *Energies*, *13*, 3424. https://doi.org/10.3390/en13133424

Mass Save. (2023a). *Residential Heat Pump Qualified Product List*. https://www.masssave.com/residential/rebates-and-incentives/air-source-heat-pumps/heat-pump-qualified-list

Mass Save. (2023b). *Air Source Heat Pump Rebates*. https://www.masssave.com/en/residential/rebates-and-incentives/air-source-heat-pumps

Massachusetts Attorney General's Office. (2020, June 4). *Petition of the Office of the Attorney General Requesting an Investigation into the impact on continuing business operations of local gas distribution companies as the Commonwealth achieves its target 2050 climate goals*. DPU 20-80.

Massachusetts Attorney General's Office. (2022, May 6). *Regulatory Recommendations of the Office of the Attorney General*. DPU 20-80.

Massachusetts Attorney General's Office & Massachusetts Department of Energy Resources. (2022, February 14). *Comments of the Office of the Attorney General and the Department of Energy Resources*. DPU 20-80.

Massachusetts Commission on Clean Heat. (2022). *Final Report*. https://www.mass.gov/info-details/commission-on-clean-heat-issues-final-report

Massachusetts Department of Energy Resources. (2019). *Offshore Wind Study*. https://www.mass.gov/service-details/offshore-wind-study

Massachusetts Department of Energy Resources. (2022, October 17). *Final Comments of the Department of Energy Resources*. DPU 20-80.

Massachusetts Department of Public Utilities. (2020, October 29). *Vote and Order Opening Investigation*. DPU 20-80.

Massachusetts Department of Public Utilities. (2022a, March 24). *Hearing Officer Memorandum Regarding Procedural Schedule*. DPU 20-80.

Massachusetts Department of Public Utilities. (2022b, December 9). *Order on Petition of Liberty Utilities for Review and Approval of an Agreement to Purchase Renewable Natural Gas from Fall River RNG LLC and of the Liberty RNG Program*. DPU 22-32.

Massachusetts Department of Public Utilities. (2022c, December 9). *Order on the Petition of NSTAR Gas Company d/b/a Eversource Energy for Authorization by the Department of Public Utilities to Distribute Gas in the Town of Douglas, Massachusetts, pursuant to the provisions of G.L. c. 164, § 30*. DPU 22-107.

Massachusetts Department of Public Utilities. (2023). *Energy Efficiency Three-Year Plans Orders and Guidelines*. Mass.Gov. https://www.mass.gov/guides/energy-efficiency-three-year-plans-orders-and-guidelines

Massachusetts Executive Office of Energy and Environmental Affairs. (2022). *Massachusetts Clean Energy and Climate Plan for 2050*. https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050

May, R. M., Goebbert, K. H., Thielen, J. E., Leeman, J. R., Camron, M. D., Bruick, Z., Bruning, E. C., Manser, R. P., Arms, S. C., & Marsh, P. T. (2022). MetPy: A Meteorological Python Library for Data Analysis and Visualization. *Bulletin of the American Meteorological Society*, *103*(10), E2273–E2284. https://doi.org/10.1175/BAMS-D-21-0125.1

McBride, J. R. (2022). *Clean heat at what cost? Economic optimization of residential space heating in Massachusetts* [Thesis, Massachusetts Institute of Technology]. https://dspace.mit.edu/handle/1721.1/144617

Mims Frick, N., Wilson, E. J., Reyna, J., Parker, A. S., Present, E. K., Kim, J., Hong, T., Li, H., & Eckman, T. (2019). *End-Use Load Profiles for the U.S. Building Stock: Market Needs, Use Cases, and Data Gaps* (NREL/TP--5500-75215, DOE/GO--102019-5217, 1576489; p. NREL/TP--5500-75215, DOE/GO--102019-5217, 1576489). https://doi.org/10.2172/1576489

National Renewable Energy Laboratory. (2022). *End Use Savings Shapes Residential Dataset Round 1*. https://www.nrel.gov/buildings/end-use-load-profiles.html

New Hampshire Department of Business and Economic Affairs. (2022). *State, County, and Municipal Population Projections: 2020-2050*. https://www.nh.gov/osi/data-center/documents/2022-state-county-municipality-projections-final-report.pdf

New York Public Service Commission. (2022a, May 12). *Order Adopting Gas System Planning Process*. Case 20-G-0131.

New York Public Service Commission. (2022b, May 12). *Order on Implementation of the Climate Leadership and Community Protection Act*. Case 22-M-0149.

New York State Climate Action Council. (2022, December). *New York's Scoping Plan*. https://climate.ny.gov/resources/scoping-plan/

Northeast Energy Efficiency Partnerships. (2023). *CcASHP Specification & Product List*. https://neep.org/heating-electrification/ccashp-specification-product-list

California Global Warming Solutions Act of 2006, AB 32, California State Legislature, 2005–2006 (2006).

NYSERDA. (2022). *Potential of Renewable Natural Gas in New York State* (21–34).

OikoLab. (2023). *Weather and Climate Data for Analysts*. oikolab.com

O'Neill, B. C., Tebaldi, C., van Vuuren, D. P., Eyring, V., Friedlingstein, P., Hurtt, G., Knutti, R., Kriegler, E., Lamarque, J.-F., Lowe, J., Meehl, G. A., Moss, R., Riahi, K., & Sanderson, B. M. (2016). The Scenario Model Intercomparison Project (ScenarioMIP) for CMIP6. *Geoscientific Model Development*, *9*(9), 3461–3482. https://doi.org/10.5194/gmd-9-3461-2016

Pereira v. New England LNG Co., Inc., 364 Mass. 109 (Massachusetts Supreme Judicial Court 1973).

Prause, E. (2022). *Modernizing Gas Utility Planning: New Approaches for New Challenges*. Regulatory Assistance Project.

Sargent, M. R., Floerchinger, C., McKain, K., Budney, J., Gottlieb, E. W., Hutyra, L. R., Rudek, J., & Wofsy, S. C. (2021). Majority of US urban natural gas emissions unaccounted for in inventories. *Proceedings of the National Academy of Sciences*, *118*(44), e2105804118. https://doi.org/10.1073/pnas.2105804118

Seavey, D. (2021). *GSEP at the Six-Year Mark: A Review of the Massachusetts Gas System Enhancement Program*. Gas Transition Allies. https://www.gastransitionallies.org/gsep

Seavey, D. (2022, April 26). Spending billions fixing gas system makes no sense. *CommonWealth Magazine*. https://commonwealthmagazine.org/opinion/spending-billions-fixing-gas-system-makes-no-sense/

Sepulveda, N. A., Jenkins, J. D., Edington, A., Mallapragada, D. S., & Lester, R. K. (2021). The design space for long-duration energy storage in decarbonized power systems. *Nature Energy*, *6*(5), Article 5. https://doi.org/10.1038/s41560-021-00796-8

Shankman, S. (2022, May 12). *Two years after asking for future of gas investigation, Healey asks state to reject results*. The Boston Globe. https://www.bostonglobe.com/2022/05/12/science/two-years-after-asking-future-gas-investigation-healey-asks-state-reject-results/

Shoukas, G., Bonnema, E., Paranjothi, G., Faramarzi, R., & Klun, L. (2022). *Performance Assessment of High Efficiency Variable Speed Air-Source Heat Pump in Cold Climate Applications*. National Renewable Energy Lab.(NREL), Golden, CO (United States).

Sorrell, S., Dimitropoulos, J., & Sommerville, M. (2009). Empirical estimates of the direct rebound effect: A review. *Energy Policy*, *37*(4), 1356–1371. https://doi.org/10.1016/j.enpol.2008.11.026

Staffell, I., & Pfenninger, S. (2018). The increasing impact of weather on electricity supply and demand. *Energy*, *145*, 65–78. https://doi.org/10.1016/j.energy.2017.12.051

Storrow, B. (2022, October 14). *N.M. enacted a climate law 3 years ago. Then things got hard.* E&E News by POLITICO. https://www.eenews.net/articles/n-m-enacted-a-climate-law-3-years-ago-then-things-got-hard/

Swan, L. G., & Ugursal, V. I. (2009). Modeling of end-use energy consumption in the residential sector: A review of modeling techniques. *Renewable and Sustainable Energy Reviews*, *13*(8), 1819–1835. https://doi.org/10.1016/j.rser.2008.09.033

Tarroja, B., Chiang, F., AghaKouchak, A., Samuelsen, S., Raghavan, S. V., Wei, M., Sun, K., & Hong, T. (2018). Translating climate change and heating system electrification impacts on building energy use to future greenhouse gas emissions and electric grid capacity requirements in California. *Applied Energy*, *225*, 522–534. https://doi.org/10.1016/j.apenergy.2018.05.003

Climate Leadership and Community Protection Act, S6599, New York State Legislature, 2019-2020 Lesigslative Session (2019).

Tonn, B., Rose, E., & Hawkins, B. (2018). Evaluation of the U.S. department of energy's weatherization assistance program: Impact results. *Energy Policy*, *118*, 279–290. https://doi.org/10.1016/j.enpol.2018.03.051

University of Virginia Weldon Cooper Center, D. R. G. (2018). *National Population Projections*. https://demographics.coopercenter.org/national-population-projections/

U.S. Census Bureau QuickFacts: Vermont; Rhode Island; New Hampshire; Maine; Massachusetts; Connecticut. (2022). https://www.census.gov/quickfacts/fact/table/VT,RI,NH,ME,MA,CT/PST045222

U.S. Department of Energy. (n.d.). *Weatherization Assistance Program*. Retrieved July 30, 2023, from https://www.energy.gov/scep/wap/weatherization-assistance-program

U.S. Department of Energy Office of Scientific and Technical Information. (2022). *Electrification Futures Study Scenarios of Electric Technology Adoption and Power Consumption for the United States*. https://data.nrel.gov/submissions/92

U.S. Energy Information Administration (EIA). (2021). *U.S. CO2 emissions from energy consumption by source and sector, 2021*. https://www.eia.gov/energyexplained/energy-and-the-environment/images/CO2-spaghettichart-2021.pdf

U.S. Energy Information Administration (EIA). (2023a). *Natural Gas Residential Consumption, Annual*. https://www.eia.gov/opendata/browser/co2-emissions

U.S. Energy Information Administration (EIA). (2022). *Natural gas explained: Natural gas pipelines*. https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php

U.S. Energy Information Administration (EIA). (2023b). *State Profiles and Energy Estimates*. https://www.eia.gov/state/

US EPA, O. (2015, December 29). *Sources of Greenhouse Gas Emissions* [Overviews and Factsheets]. https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

Vaishnav, P., & Fatimah, A. M. (2020). The Environmental Consequences of Electrifying Space Heating. *Environmental Science & Technology*, *54*(16), 9814–9823. https://doi.org/10.1021/acs.est.0c02705

van Ruijven, B. J., De Cian, E., & Sue Wing, I. (2019). Amplification of future energy demand growth due to climate change. *Nature Communications*, *10*(1), Article 1. https://doi.org/10.1038/s41467-019-10399-3

Waite, M., & Modi, V. (2020). Electricity Load Implications of Space Heating Decarbonization Pathways. *Joule*, *4*(2), 376–394. https://doi.org/10.1016/j.joule.2019.11.011

Wallace, N., Zerbe, A., & Wara, M. (2020). *Removing Legal Barriers to Building Electrification*. Stanford Law School Environmental Law Clinic.

Wasser, M. (2023, March 15). *Healey appointees tasked with 'transforming' the Department of Public Utilities*. WBUR. https://www.wbur.org/news/2023/03/15/department-of-public-utilities-dpu-commission-nostrand-fraser-rubin

White, P. R., Rhodes, J. D., Wilson, E. J. H., & Webber, M. E. (2021). Quantifying the impact of residential space heating electrification on the Texas electric grid. *Applied Energy*, *298*, 117113. https://doi.org/10.1016/j.apenergy.2021.117113

Wilcox, S., & Marion, W. (2008). *Users manual for TMY3 data sets*.

Wilson, E. J., Christensen, C. B., Horowitz, S. G., Robertson, J. J., & Maguire, J. B. (2017). *Energy Efficiency Potential in the U.S. Single-Family Housing Stock* (NREL/TP--5500-68670, 1414819; p. NREL/TP--5500-68670, 1414819). https://doi.org/10.2172/1414819

Wilson, E., Parker, A., Fontanini, A., Present, E., Reyna, J., Adhikari, R., Bianchi, C., CaraDonna, C., Dahlhausen, M., Kim, J., LeBar, A., Liu, L., Praprost, M., Zhang, L., DeWitt, P., Merket, N., Speake, A., Hong, T., Li, H., … Li, Q. (2022). *End-Use Load Profiles for the U.S. Building Stock: Methodology and Results of Model Calibration, Validation, and Uncertainty Quantification* (NREL/TP-5500-80889, 1854582, MainId:78667; p. NREL/TP-5500-80889, 1854582, MainId:78667). https://doi.org/10.2172/1854582