Decarbonization of residential space and water heating in California

by

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Committee in charge:

Professor Duncan S. Callaway, Chair
Professor Michael O'Hare
Professor Catherine Wolfram

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Abstract

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This dissertation investigates options that exist to reduce emissions from residential space and water heating over the next few decades. There are four main research questions that I aim to answer:

1. What is the most promising route to decarbonizing residential space and water heating?
2. If heating becomes electrified, what new electric loads should we expect?
3. How might the building stock transition to electrified heating, and how can this transition occur at minimum cost?
4. What policy changes are necessary in California to encourage electrification?

These research questions are tackled one at a time, in each of the main chapters of the dissertation. In Chapter One I look specifically at California and build the case for why energy efficiency with electrification of heating is the most likely path to achieve the large carbon emission reduction needed from this sector. I examine alternative decarbonization strategies, such as solar thermal, biogas, synthetic natural gas, and electrification and show why electrification is likely to be the most promising path. I evaluated these options across the dimensions of scale, cost, and suitability. I find that electrification has the potential to serve all heating loads, while the other options may serve only 2-70% of loads. I also expect that electrification could reduce emissions from this sector at less than 1/2 the cost of other options. While electrification may be the most promising path in California, it is not necessarily the most promising path in all regions. The benefits of electrification and its limitations are discussed.

In Chapter Two, I estimate what new electric loads might look like if existing natural gas space and water heating transition to electric heat pumps. In order for electrification to gain support from policymakers, system operators, and utilities we need to better understand what impacts electrification of space and water heating would have on the grid. The electricity grid needs to be prepared for the additional load, and in order to do that we need to better understand the characteristics of new heating loads. I present a new method for estimating hourly residential space heating and water heating demand using hourly electricity consumption data (smart meter data) and daily natural gas data. This estimate was done using a dataset of 30,000 customer accounts in Northern California. I applied linear regression at both the individual house level and to hourly, climate-band-averaged whole-home electricity consumption, climate-band-averaged whole-home gas consumption, and outdoor air temperature data to determine both the hours when heating is more active and the outdoor temperature dependence of that consumption. This varying temperature responsiveness allowed me to assign varying amounts of space heating load to different hours. I then scaled up the results to the entire utility service area to show when and where electric heating will impact peak demand. About 1/2 of the residential space and water heating gas use could be electrified without any impact on peak demand. I also find that electrification of space and water heating would increase the load factor by at least 5%—and even more if heating loads are controllable. While electrification of heating would have little impact on peak demand on a systemwide basis (until very high penetration), at the distribution level electrifying heating loads may have an impact on peak demand for feeders that are mostly residential.

In Chapter Three I show how California could deploy hot water heaters to meet different emissions targets at lowest cost. I describe several scenarios and show what the lowest cost pathway would be as emissions are constrained. Different water heating technologies are considered, such as gas tank, gas tankless, electric resistance, and electric heat pump, and high efficiency electric heat pump with CO_2 refrigerant. Emissions from natural gas leakage and refrigerant leakage are both considered. I have developed a linear program that minimizes total present operating and capital cost of statewide residential water heating. Relative to the lowest cost case, adding cumulative emissions targets can lower emissions from 71% to 77% without early retirement of water heating appliances. In order to meet a 90% reduction goal from the sector in 2050 (while minimizing cumulative emissions), heat pump water heaters need to have full market share in new construction immediately unless efficiency standards are increased, and most scenarios suggest that the lowest cost pathway include a transition to electric water heating that should have already occurred. Heat pumps need to begin replacing existing gas water heaters by the early 2030s at the latest, while most scenarios suggest that this transition should have already happened to minimize cost. Given projections for gas and electricity prices and costs of water heating equipment, an emissions target of a 90% reduction in 2050 relative to 2010 emissions could be met at a cost of \$97-153/ton CO_2 relative to the unconstrained, lowest cost case. Delaying action beyond 2017 makes the cumulative emissions target unreachable in two scenarios, while a third scenario allows delay until 2029, at a carbon cost of over \$200/ton CO_2.

Finally, in Chapter 4 I examine potential policy changes that could be made to encourage a transition to electric space and water heating. Current energy policies and economics give an advantage to natural gas appliances over electric appliances. Simultaneously, California's climate policy is aiming for very large reductions in emissions, which will either be impossible or costly without a phase out of many natural gas end uses. Aligning energy and climate policy is possible, but will require several changes. Some potential suggestions are offered in this chapter mostly related to changes to the building energy code. In addition to changes to building codes, other options are also possible such as redesigning electricity rates that properly reward flexible loads. Specific legislation may also be required to jump start a transition to electric heating. Such policies have been put in place in the past to support other technologies that may have even less climate benefit per dollar.

For my parents.

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My research direction has changed countless times over the course of my graduate school career, and I have been incredibly fortunate to have had Duncan Callaway as an advisor; he has supported me through this process of discovery and I am grateful for his patience and encouragement even when, at times, it seemed like a destination was nowhere in sight.

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Chapter 1

The case for electrification of space and water heating in California

Preface

In this chapter, I show why carbon reductions are necessary in the space and water heating sector and compare different decarbonization options across the dimensions of scale, cost, and feasibility. In so doing, I build the case that electrification is the most promising option and therefore provide motivation for deeper study (in later chapters) of the implications of electrifying space and water heating systems in California. I performed this work with the guidance of my advisor, Duncan Callaway.

Chapter Abstract

In order to meet ambitious carbon reduction goals, direct combustion of fossil fuels in homes will need to largely cease. The largest portion of this reduction will likely come from energy efficiency, but efficiency alone will not be sufficient. In this chapter we look specifically at California and build the case for why energy efficiency with electrification of heating is the most likely path to achieve the large carbon emission reduction needed from this sector. We examine alternative decarbonization strategies, such as solar thermal, biogas, synthetic natural gas, and electrification and show why electrification is likely to be the most promising path. We evaluate these options across the dimensions of scale, cost, and suitability. We find that electrification has the potential to serve all heating loads, while the other options may serve only 2-70% of loads. We also expect that electrification could reduce emissions from this sector at less than 1/2 the cost of other options. While electrification may be the most promising path in California, it is not necessarily the most promising path in all regions. We discuss the benefits of electrification and its limitations.

1.1 Introduction

California has an ambitious goal of reducing carbon emission 80% below 1990 levels by 2050 [1], and in order to meet this goal all aspects of the energy system will need significant changes. Impressive progress already has been made: a rapidly expanding share of renewables in electricity generation, exciting advancements in electric vehicles and lower carbon fuels, and almost 40 years of pioneering energy efficiency policy.

Technical potential studies show that meeting such aggressive 2050 emission reduction goals is possible in California, the US, and Europe, but these studies consistently include substantially reducing or eliminating direct emissions from residential space and water heating as a necessary measure [2, 3, 4, 5, 6, 7]. In order to achieve a goal of emissions getting to 80% below 1990 levels by 2050, it is likely that emissions from buildings will need to decrease by even more than 80%. The Deep Decarbonization study found that in order for the US to reduce emissions 80% below 1990 levels by 2050 (the level necessary for limiting global warming to 2 degrees Celsius), the emissions from buildings would need to decrease by even more. They consider four scenarios which reduce emissions by 87% relative to a baseline 2050 case, and 86% below 2014 emissions. Much larger reductions come from the residential sector, with reductions ranging from 89-98%, depending on the scenario [4]. Reductions in other sectors like air travel, trucking, and industry may be more difficult and costly than decarbonizing buildings.

There has been little progress so far in reducing emissions, and current trends suggest that, without strong action, emissions reductions will not be met. Figure 1.1 shows how much gas the residential and commercial sectors have used in California [8]. Commercial gas use includes natural gas used in vehicles through 1996, so the commercial trendline is based on post-1996 data. The 2050 points show what an 80% reduction from 1990 levels would look like in 2050. Energy efficiency potentially could make up part of this reduction, but all of the efficiency programs of the past 25 years have basically kept gas consumption flat.

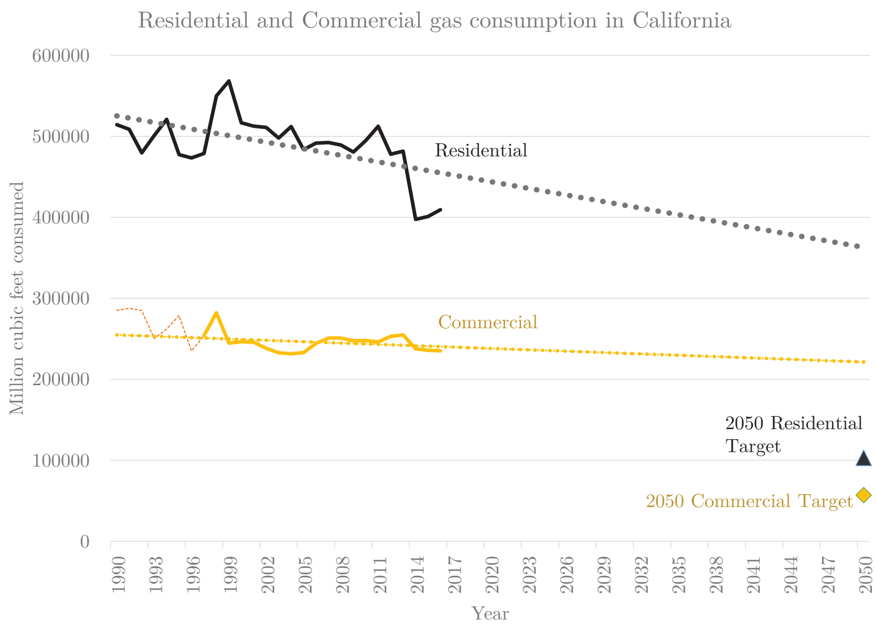

Figure 1.1: Historical natural gas consumption in the residential and commercial sectors in California.

Historically, the residential space and water heating sector has received little attention in climate policy relative to larger emissions sources like electricity generation and transportation. While this sector represents a much smaller share of total emissions, the complexity of achieving the necessary changes is profound: it requires changes over long timescales with which buildings change, and it requires an understanding of how consumers adopt new technologies. Policymakers need to devote attention to this sector soon.

Changing how we heat space and water requires irreversible decisions. For example, investing in decarbonized gas infrastructure might lock us in to that pathway for decades, while moving away from gas would impact investments in natural gas infrastructure and force us to rethink subsidies for gas-efficient appliances. As customers electrify heating and less gas is sold, the delivery cost of each unit of gas would increase to cover the fixed costs of maintaining gas infrastructure. Greater electricity consumption, particularly if new heating loads are flexible, could increase load factors of electricity infrastructure leading to lower electricity prices. Widespread fuel switching could potentially lead to a death spiral in which retail gas prices rise, electricity prices fall, and customers continue to switch away from gas.

Political and institutional barriers exist that will make the energy system slow to change. Gas utilities, particularly those that are separate from electric utilities, would strongly resist policies that reduce their earnings. Customers surely would also resist either being disconnected from a gas supply or having to pay exorbitant rates to cover infrastructure costs. Choosing another path, such as decarbonized gas, would require large infrastructure investments in facilities that can produce biogas or synthetic methane. If such investments are made, they may encourage continued gas use for space and water heating. We need to decide which path is better—though different optimal paths may exist in different locations. Since the building stock is slow to change, policies need to be put in place soon. In order to avoid stranded investments, maximize cumulative emissions reductions, and achieve carbon reductions at the lowest cost, policy and planning is required now to drive investment in lower carbon alternatives and to plan for infrastructure changes. In this chapter, we compare different strategies that could achieve emissions reductions in the residential sector. Utilities, analysts, and policymakers still debate which path is best [9, 10, 11, 12, 13]. Given this uncertainty, we take a deeper look at the options available.

Meeting aggressive emission reduction goals will require changes in how we heat space and water. As a whole, this dissertation examines the implications and potential pathways that California might take to electrify this sector. This introductory chapter aims to compare different strategies that we might take to achieve emissions reductions in the residential sector and to provide motivation for the deeper study of electrification that comes in future chapters.

1.2 Energy demand in the residential heating sector

In 2014 about 5% of total US greenhouse gas (GHG) emissions, or 345.1 million metric tons of CO_2-equivalent, came from combustion of fossil fuels in the residential sector [14], with about 69% of this coming from space heating and 22% from water heating [15]. In California, a similar fraction of statewide GHG emissions (6%) is the result of direct combustion of fossil fuels in the residential sector [16].

In 2009, approximately 80% of households served by five major utilities in California used natural gas as the primary fuel for space heating and water heating, and those households used an average of 354 therms (37 GJ) of natural gas per year for all uses [17]. Natural gas heating dominates today in California because of the relative prices of retail electricity and natural gas, and because of the additional capital costs that come with solar water heating, heat pumps, or decarbonized pipeline gas infrastructure.

Space and water heating are not the only uses of natural gas in the residential sector, with clothes drying, pools, cooking and other miscellaneous uses accounting for about 14 percent of residential gas consumption as shown in Figure 1.2. While small amounts of gas are used in these sectors, a thoughtful decarbonization strategy would need to take these uses into account.

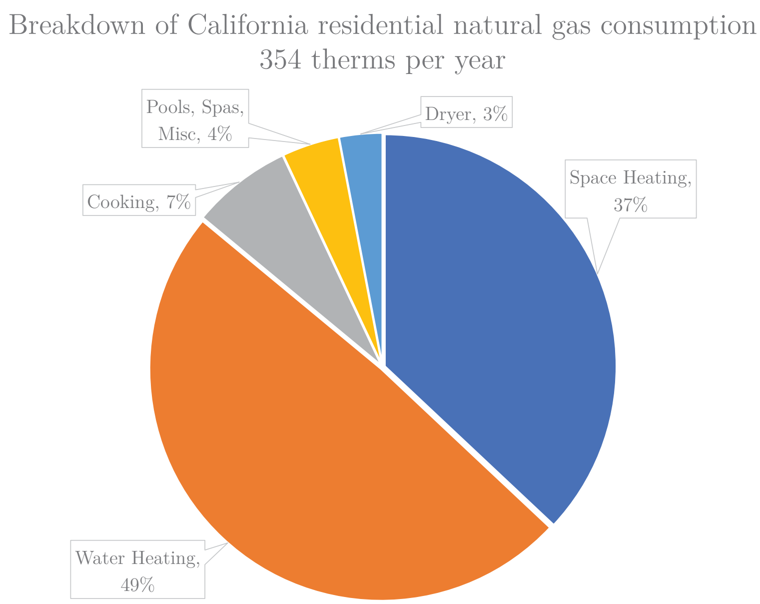

Figure 1.2: Breakdown of residential natural gas use in California in 2009 [17].

1.3 Strategies to decarbonize space and water heating

Broadly, there are four main ways in which an economy can decarbonize: energy efficiency, low carbon electricity, decarbonized fuels, and fuel-switching. These options were neatly laid out by Long et al. [5].

Taking these options and mapping them to our options for decarbonizing residential space and water heating in California, we see four similar choices: Energy efficiency, Solar thermal, Decarbonized pipeline gas (injecting biogas, synthetic methane, and/or hydrogen produced from renewable electricity into the natural gas system), and Electrification (switching from gas furnaces and boilers to heat pumps that use low carbon electricity). These options come with different services, costs, speeds, scales, and implications for market participants. Developing effective policy to meet emission reduction goals must take into account the attributes of the various alternatives. This paper evaluates the options and concludes that electrification of heating, with improved energy efficiency, will be the preferred path to meet emission reductions goals of the residential space and water heating sector in California. Strategies for other regions are also discussed.

With the exception of energy efficiency, we evaluate each decarbonization option by asking three basic questions:

1. Is there enough?
2. How much would it cost?
3. What is the best end use of this resource?

Energy Efficiency

Energy efficiency has long been considered the "cheapest, cleanest, fastest" energy resource [18]. Efficiency can take many forms, such as more efficient appliances, changes to industrial processes, deep retrofits of existing buildings, weatherization, and advanced vehicles. Energy efficiency alone will be insufficient to reduce emissions by 80% or more by 2050. Even aggressive efficiency improvements that save 2% per year would reduce emissions by only 50% over the next 35 years. Such a rate of efficiency improvement would be far greater than we have seen in the recent past. Over the last 35 years we have seen a decrease in energy intensity (energy use per dollar of GDP) of 50% in the United States, but much of this has been due to structural changes in the economy. Nadel et al. estimate that 60% of this decrease in energy intensity came from energy efficiency and that over the next 35 years a reduction of energy use by 40-60% could be cost effective through more efficient equipment, zero net energy buildings, industrial improvements, deep building retrofits, and advanced vehicles [19]. Wei et al. estimate that energy efficiency could lead to 43% emission reduction in California [2]. Reaching such improvements in energy efficiency would require sustained improvements in energy efficiency that yield 1.5% reductions in energy use every year. Loftus et al. reviewed 17 decarbonization scenarios in the literature, the least aggressive of which included reductions in energy intensity in the range of 1.6–1.9%. They also point out that since 1970 global energy intensity has improved greater than 1.5% only a few times [20]. Total energy use may increase as energy intensity decreases because energy intensity is based on economic activity. In order to save energy in absolute terms, energy intensity will need to come down at a rate greater than economic growth. Reaching absolute savings in the 40–60% range will require a sustained rate of efficiency savings that has not been seen before. Even if those aggressive savings targets are achieved, they will be insufficient to meet decarbonization goals.

We will need to look beyond efficiency. After also accounting for additional demand, energy efficiency alone is unlikely to get us even halfway to our 2050 emissions goal. While energy efficiency is difficult to fit exactly into the evaluation framework that we laid out, our main interest in this paper is to consider what else needs to be done, beyond efficiency, to reach a more aggressive decarbonization goal.

Solar Water Heating

Solar thermal options like solar watering heating (SWH) or even passive solar design for space heating are similar to energy efficiency measures because they simply reduce demand for other fuels to provide an energy service. Solar water heating works by running water or some other heat transfer fluid through collectors on rooftops. If another fluid is used, the heat is exchanged to heat up water. This hot water is stored in a tank and either used directly or, if not hot enough, heated with an electric or gas water heater.

Is there enough? A typical solar fraction of solar water heating is in the 0.5 to 0.7 range which means that 30-50% of another fuel is used after installing a solar hot water system [21]. Of course, it is possible that a larger system could be installed that would increase the solar fraction, but such a system would be uneconomic because it would produce unusable heat at certain times of year or cause overheating of the system. At some point, the marginal unit of heat produced would come at a price far higher than producing that heat from electricity or natural gas. If we assume that all buildings would be suitable for SWH installations, we might assume that 70% of emissions could be reduced. Unfortunately, not all buildings will have the proper orientation.

How much would it cost? A 2009 Itron study found that the average cost of SWH systems cost $6,358 with an average levelized cost of saved energy of $2.52/therm ($23.86/GJ) for systems that displaced gas and $0.104/kWh for systems that displaced electricity, assuming a 25-year life with no additional maintenance issues over the life of the system [21]. However, in practice it will require periodic inspections and maintenance. With a price premium of saved energy of about $1.20/therm over the retail price of natural gas, that would be equivalent to a carbon tax of $200 per ton of CO_2. As part of the study, they also compared these installed costs with other market data in Hawaii, Oregon, Northern Europe, China, and India. Average costs in all regions other than China and India were similar (within about $1000). Costs in China and India were found to be less than one tenth the cost in California. This may be due to smaller systems and lower labor costs. If very large cost reductions for SWH are possible (and they outpace cost reductions in PV systems) then SWH may play an important role in decarbonizing. But today, the economics clearly favor solar photovoltaic with heat pump water heating in California.

What is the best end use for this resource? The resources that SWH uses are rooftops and dollars. PV is a better use of both. While SWH has higher thermal efficiencies compared to solar photovoltaic (PV) panels (40% vs 15% efficient) and matches supply and end uses in energy quality [22], it is not (currently) the best use of rooftops and dollars. It is a relatively low-tech solution that potentially is also low cost. But given technology advancements and major cost reductions in PV, the case for solar water heating is diminishing. Furthermore, the efficiency difference is somewhat misleading, since they deliver different forms of energy. Electricity is far more valuable than heat. The electricity that a PV system could produce can be used in a heat pump water heater (HPWH). A heat pump could have a coefficient of performance (COP) of 3 or more, tripling the system efficiency and putting the PV on par with SWH. The COP refers to the efficiency of a heat pump (the amount of heat delivered divided by the energy consumed). COP can be higher than 1 (or 100%) because it is not converting energy into heat, but rather it is using energy to move heat from one place to another.

Solar water heating systems would certainly have an impact on reducing emissions, but they might not be the most effective use of funds. Let us consider a

> few scenarios. First, if the consumer has an electric resistance hot water heater, they could switch to a heat pump and gain about the same energy savings at half the cost, with the average installed cost of a HPWH being around $3000. If they already have a HPWH, the value of the energy savings that would come from a SWH would be cut by a factor of 2 or more—leading to a cost of saved electricity twice as much as what was found in the Itron study. If a heat pump already was installed, the economics of adding solar water heating would not be favorable, as the cost of saved energy would be far higher than the cost of energy. On the other hand, if SWH were installed first, the economics of switching from a resistance to a heat pump would not be favorable. The order of events matters a lot.

The biggest drawback of SWH is that they simply do not reduce emissions enough. If the goal is to eliminate residential emissions from natural gas combustion, then cutting only two thirds of those emissions from water heating still leaves us far from our goal. Policymakers should be cognizant of the impact that SWH could have in the future. While SWH might reduce emissions today, choosing SWH could lock remaining emissions in further into the future by changing the future economics of electrification. Instead of spending $6000 on a SWH system, a homeowner could choose to spend $3000 on a HPWH and $3000 on a 1 kW PV system [23]. [1] This would provide a greater climate benefit. That PV system could produce 1555 kWH/year in San Francisco [24], or 159 therms (17 GJ) of heat delivered with a COP of 3. The average Pacific Gas and Electric customer used 183 therms (19 GJ) for water heating, which assuming an 80% efficient hot water heater, is 146 therms (15 GJ) of delivered water heating energy. In other words, the $6000 spent on a HPWH+PV system would be net zero energy, while the SWH would cut energy only by about 2/3. While HPWH+PV might be zero net energy, it would not necessarily be zero emissions since not all consumption would come directly from the PV, and the energy sold back to the grid might displace lower emission generation than the energy that would be bought from the grid. This analysis compares the costs of systems at the household level to give a sense of the economics of SWH and PV. While all new residential buildings in California will need to be zero net energy by 2020, not all buildings will necessarily be well suited for PV installations. PV may be installed even cheaper at the grid scale, though SWH does not have that possibility without installing district heating infrastructure.

Despite challenging economics for SWH, in some scenarios it could be a part of the mix. Solar fraction (the fraction of total annual water heating energy use that

[1] This assumes a $3/W installed PV cost. The total installed cost of a residential PV systems in 2015 was $4/W on average in the US and $1.7/W in Germany.

is supplied by the SWH system) can vary widely between northern and southern California, ranging from 0.55 to greater than 0.85 [25]. SWH in areas with very high solar fractions could be a part of a smart decarbonizing strategy, particularly with cost reductions—though those areas also will have more productive PV systems.

A variety of decarbonization options, like SWH, will be important to hedge risk of other strategies not delivering on their potential to decarbonize the water heating sector. SWH are an old, proven technology and can deliver emissions reductions. Because of their high cost, they should not be the first choice for decarbonizing water heating. For space heating, SWH could be useful in buildings that use hot water to distribute heat, and it could also be useful in new construction with hydronic heating systems, but the transition cost of existing buildings would be cost prohibitive.

Photovoltaic thermal hybrid solar collectors (PVT) generate both electricity and heat. The system efficiency is higher because the PV can operate more efficiently when cooler, and some energy that is not converted to electricity is captured as heat. With cost reductions, PVT systems could also potentially decarbonize heating more cheaply than PV + HPWH. Further research, development, and deployment is needed to drive costs down.

Decarbonized Pipeline Gas

Another decarbonization option is to leave heating systems in the building stock alone but distribute fuels that have lower lifecycle carbon emissions. The biggest advantage of this strategy is that it requires no action on the part of consumers. Motivating consumers to take action when it comes to energy use has been challenging and well documented in the energy efficiency gap literature. Transitioning to SWH or electric heating would be another case in which a large number of consumers would need to take coordinated actions to reduce carbon emissions. Experience with energy efficiency investments show that consumers are hesitant to respond, have high hurdle rates to make efficiency investment, only invest with very short paybacks—and often do not get the expected savings [26, 27, 28, 29]. Decarbonized pipeline gas overcomes these barriers, and of the four strategies to decarbonize space and water heating, only decarbonizing pipeline gas can be achieved through central planning. Along with this benefit, decarbonizing pipeline gas would also be preferable for natural gas utilities because it would allow their business to survive while meeting deep decarbonization goals. Decarbonizing pipeline gas makes it easy for consumers and avoids resistance from the natural gas industry.

Three main options fall into this category of fuel: biogas, hydrogen, and synthetic methane. We discuss these options in greater detail in this section.

Biogas

If decarbonized gas were used to reduce emission from space and water heating end uses in California, it would most likely come predominantly from biogas. A recent study of the costs of decarbonizing using an electric only or mixed case (which included decarbonized gas) found that costs were comparable for both options [12]. This study relied on California receiving a population-weighted share of all biomass produced in the United States in a best-case scenario of biomass production [30]. The other environmental impacts of such a high level of biomass production were not taken into account. This study along with several other studies funded by the natural gas industry have concluded that "renewable gas" is a realistic path to decarbonize residential gas end uses. Biomass can be considered to be decarbonized since there are low net emissions when it is combusted. While combustion still releases CO_2, there are avoided emissions that would have occurred had the biomass decomposed.

Biogas could come from either anaerobic digestion or thermochemical processes that take animal waste, energy crops, wastewater, municipal solid waste, or wood and agricultural residues as inputs. The environmental impacts of these feedstocks vary widely. On one hand, combusting methane that is being produced anyway, such as landfill gas, could have a positive impact. On the other hand, production of other dedicated energy feedstocks might have other negative environmental impacts and land use change impacts. Directing some feedstocks to energy uses might have net negative impacts, such as the reuction of organic material available for composting.

Is there enough? The simple answer is no, there is not enough biogas to serve all current natural gas uses. Even with very aggressive growth in biomass production, it will be challenging to replace our current use of fossil fuels. The total consumption of natural gas in 2016 was 28.5 quadrillion BTUs. Today biomass makes up about 5% of total primary energy consumption in the United States [31] or about 4.95 quadrillion BTUs out of 97.4 quadrillion BTUs in 2016. If we assume that a dry ton of biomass is equivalent to 16 million BTUs of primary energy, as was done in a recent DOE report [30], then that assumes about 309 million dry tons of biomass were used in 2016. This is considerably higher than Perlack et al.'s 2012 estimate of 214 million dry tons in the Billion Ton Study. Either the 2012 estimate was low, the EIA counts biomass uses that were not included in the Billion Ton Study, or the energy content of biomass is greater than 16 million BTU per dry ton. For the purposes of this analysis, this difference is noted, but it is small relative to the potential increase in biomass production. Depending on the scenario, Perlack et al. find that 2030 biomass production could range from 1094 to 1633 million dry tons [30]. However, since we are interested in examining the potential of biomass to replace fossil fuels, the energy content of this resource needs to be derated. The conversion efficiency of biomass to biogas may range from 62-81% and the efficiency of converting biomass to ethanol ranges from 46-56% [32]. Depending on the type of generator, conversion of biomass to electricity is likely less efficient than coal or gas plants, with a heat rate of 13,000 BTU per kWh rather than typical heat rates of 10,000 BTU/kWh for coal steam generators and 7600 BTU/kWh for combined cycle gas generators [33]. While biomass may contain on average 16,000 BTU per dry ton, this energy is less usable than other fossil energy resources. In order to have a fair comparison with fossil fuels, we conservatively derate the energy potential of biomass by 25% in Figure 1.3.

We find that, relative to all fossil fuels currently used, aggressive biomass production above current biomass consumption use could replace 19% of current fossil fuel consumption, or provide a total of about 19 quads of primary energy annually. Other renewable generation will likely reduce some of this future demand for fossil fuels, but biomass is nowhere close to meeting all of our energy needs. Two other studies by the natural gas industry, one by National Grid and another by the American Gas Foundation examined the potential for “renewable gas” in the the Northeast and US respectively. National Grid found that the technical potential of renewable gas could serve 16% of existing gas demand in MA, NY, NH, and RI [34]. A broader nationwide study by the American Gas Foundation found that renewable gas could serve 1-2.5 quadrillion BTUs per year, with a technical potential of up to 9.5 quadrillion BTUs [35]. Studies consistently show that biomass alone can provide only 1-20% of our primary energy needs.

How much would it cost? It is tough to say what the mature market price of biogas would be. With the assumption that the biomass resources would cost $60/ton [30] and that ton would produce about 90 therms [12], the per therm price of the feedstock alone would be 66 cents per therm, which is about double current Henry Hub gas prices [36]. Recent biogas prices have been double the projected feedstock price, or four times the natural gas market price [37]. If we assume that biogas has a price premium of $1.80/therm, that would be equivalent to a carbon tax of $295 per metric ton of CO_2. [2]

What is the best end use for this resource? If our broad goal is to decarbonize and reduce the use of fossil fuels, biomass will be able to play a larger role than it currently does. But as shown above, it is not large enough alone. Given

[2]Assuming a carbon intensity of natural gas of 13.446 lbs/therm [38]

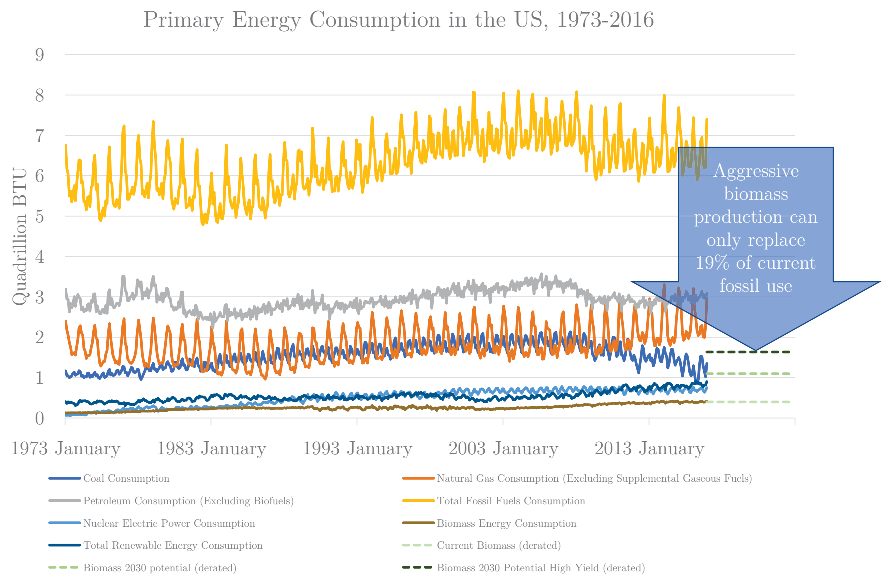

Figure 1.3: Primary energy consumption in the US 1973-2016 and the potential for biomass.

that the biomass supply will be constrained (particularly if we want to avoid the worst environmental side effects of increased biomass productions) there certainly will be better uses for it than space and water heating in California. Some existing end uses, like industrial process heat, heavy duty vehicles, and aviation will be more challenging to decarbonize, so biomass resources would have a bigger impact for those end uses.

In addition to these end uses, biomass could be used for electricity generation which would also be a more effective use than residential heating. A ton of biomass can be converted to about 9.5 GJ of biogas or 6.5 GJ of electricity through combustion [12]. Combustion provides three benefits. First, 6.5 GJ of electricity is more valuable for heating than 9.5 GJ of biogas. When used in a heat pump a GJ of electricity delivers 2-3 GJ of heat. One GJ of biogas on the other hand might deliver only 0.95 GJ of heat. While the efficiency of the conversion of biomass to biogas is higher than the efficiency of the conversion of biomass to electricity, the system efficiency is lower when we look at whole system of biomass to heat. A ton of biomass might provide 9 GJ of heat through the biogas pathway, while it could provide 19 GJ of heat through the electrification pathway. Second, combustion of biomass is about a third of the

> cost per ton than conversion to biogas. So, you derive 1.5–2 times as much heat per ton of biomass at 1/3 the cost. Finally, combustion of biomass, together with carbon capture and storage allows for negative net emissions.
>
> Higher priority uses of biomass could be as fuels in difficult to decarbonize sectors. If it is used for heating in California, it could be used far more efficiently by first converting it to electricity and electrifying heating systems. But what about the use of biomass in other parts of the country? If biogas were indeed produced for residential heating, colder climates should be given priority for this resource before California. Most parts of California have low heating demands, which means that if heating systems were electrified there would not need to be very large increases in electricity infrastructure as we will show in following chapters. This would not necessarily be the case in very cold climates where power systems would need to be much larger to support electric heating systems. Biogas could have a much bigger net impact per dollar in cold climates than in most of California.

Finally, using decarbonized gas does make it easy (on the demand side) to decarbonize gas end uses, but there are consequences. Leaking gas infrastructure can have a major environmental impact. While natural gas has been regarded as a bridge fuel from coal to renewables, some suggest that when accounting for leakage, it may not have any emissions benefit [39]. Combustion in distributed furnaces and water heaters makes carbon capture impossible.

Hydrogen and Synthetic Natural Gas

Another way to reduce emissions of residential natural gas combustion is to replace natural gas with synthetic methane or hydrogen that has been produced with low-carbon electricity. This process is known as power to gas (P2G). Similar to biogas, hydrogen or synthetic methane could be a direct replacement for natural gas in existing infrastructure. Hydrogen can be produced using excess renewable electricity to electrolyze water to generate hydrogen. This hydrogen can then be mixed in to the natural gas system at fractions up to 10% or put through a methanation process to create synthetic methane [40]. Generating hydrogen or synthetic methane from excess renewable electricity production could be a flexible load that could be used to deal with intermittency of wind and solar generation. It would also have the potential to seasonally store energy from renewables in the natural gas infrastructure both directly and by displacing other fossil gas usage by varying amounts over the year. Rather than curtailing renewables during times of overproduction, this energy could be used to produce other fuels.

As in the previous section, we ask three fundamental questions about this option.

Is there enough? In theory, the potential to produce hydrogen or synthetic methane is limited only by the amount of renewable generation and electrolyzer capacity that we choose to install. So, the answer to this question is tightly coupled to the following question about the economics. We assume that this resource will be constrained to use only excess renewable generation capacity. Energy+Environmental Economics estimates that with a 50% Renewable Portfolio Standard and diverse resources, there would be 1300 hours of overgeneration in a year, generating 5400 GWh of excess energy in California [41]. As a point of comparison, in 2015 2.3 trillion cubic feet of natural gas was used (670 TWh), 0.6 (180 TWh) of which was delivered to residential and commercial customers. The energy potential of overgeneration is less than 1% of total gas demand and less than 3% of residential and commercial gas demand. After we consider the efficiency losses of converting excess electricity into synthetic natural gas, these potentials are even smaller.

As seen in Figure 1.4 below, for every 100 units of electricity in, a power to gas conversion pathway would create about 45 units of heat. However, those same 100 units could create 275 units of heat when used directly in a heat pump. Power to gas does have the advantage of storing energy—potentially very large amounts, over long seasonal timescales—so that generation and consumption do not have to happen at the same time. But a factor of six difference in system efficiency will be hard to overcome.

Unfortunately, the system efficiency of synthetic methane production is very low, particularly when we compare it to other options. Converting electricity to hydrogen is 50-70% efficient, with methanation of that hydrogen (converting H_2 to CH_4) reducing efficiency by a few more percent. Some hydrogen could potentially be mixed directly into natural gas networks, though it is uncertain what the allowable fraction would be or how much leakage of small H_2 molecules would occur [40]. The system efficiency of the path from electricity to gas to heat looks particularly low when we compare it with using electricity directly through a heat pump. It will be for policy makers to decide if the behavioral and political benefits of this strategy outweigh the system efficiency penalty and costs.

How much would it cost? As we see from the analysis above, when electricity is available for heating, it would be far more efficient to use it directly. The benefit of P2G is that it avoids replacing gas appliances and that it can utilize unused clean electricity generation and store that energy for future use. Unfortunately

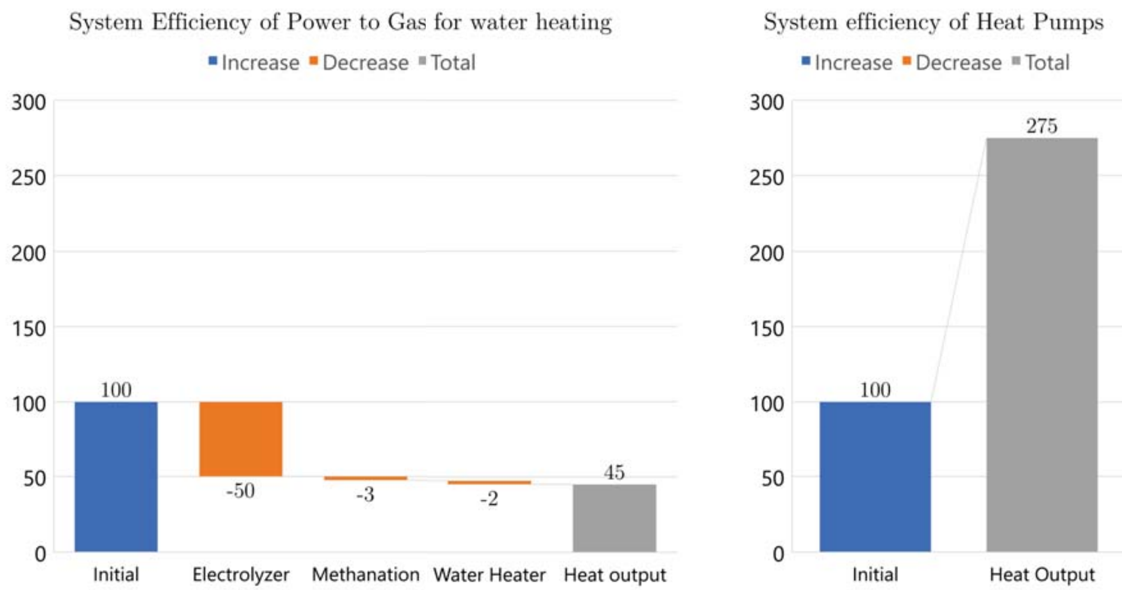

Figure 1.4: System efficiency comparison of electricity to heat via synthetic methane and direct use through a heat pump.

the cost of this conversion is very high. The main cost of producing synthetic methane or hydrogen comes from the electrolyzers which may range from 850-3200 $/kW (electric) with additional costs on the order of 150-400 $/kW if methanation is included [42, 43, 44]. Note that the electrolyzer cost is a function of the capacity (power) of the electrolyzer. Relying only on excess generation hours is not feasible because it would lead to low utilization of expensive electrolyzers. In the Energy+Environmental Economics study mentioned above there were only 1300 hours of overgeneration, so an electrolyzer that operated for all of those hours would have a capacity factor of only 15%. While the number of hours of overgeneration will likely grow as renewables make up a larger fraction of generation, if there are many hours of overproduction, other flexible demands such as electric vehicles, thermostatically controlled loads, and other forms of energy storage would likely step in to use the free or very cheap electricity. A 70% efficient electrolyzer with a 15-year life operating 15% of the time would produce synthetic natural gas at a cost of $1.80-7/therm with no discounting. The $0.70-6.30/therm price premium over natural gas would equate to about $115-1000/ton CO_2 without methanation. In reality the capacity factor would be even lower, since not all capacity would be used in all hours of overgeneration. A DOE study investigated the production price for hydrogen using either wind power and grid electricity and found a cost of production in the range of \$3.74-\$5.86 per kg of hydrogen [45]. On an energy basis, a kilogram of H_2 is about equal to 1.2 therms, so the price premium (and required carbon tax for cost effectiveness) is in the range we calculated.

What is the best end use for this resource? We might also consider how electrolyzers and synthetic methane would be used, if we made the decision to invest in electrolyzers. If the value of synthetic methane or hydrogen were high enough, they might operate even during hours that would not have been curtailed. It it also certainly possible that hydrogen or synthetic methane would not be used for decarbonizing space and water heating since other uses value it more. Hydrogen could be used more effectively as a transportation fuel in a fuel cell vehicle than burned in a residential furnace. Producing synthetic methane also requires a pure CO_2 "resource" in order to methanize hydrogen. This means that methanation has an opportunity cost of lost carbon capture and storage (CCS).

The seasonal storage benefit of renewable electricity through hydrogen or synthetic natural gas might be real, but we can potentially separate this benefit from the decision of whether to electrify residential space and water heating. If the economics were favorable for seasonal storage we could still save that energy as gas, and then use it in a fuel cell or generator and use electricity in a heat pump and come out ahead in terms of total system efficiency. While electrification of space and water heating has a shorter time scale storage/flexibility potential, it does not have the same seasonal storage attributes of synthetic methane. Such seasonal storage may be cost effective at high levels of renewables penetration.

Decarbonized gas can play a role in future energy system. Hydrogen and synthetic methane production allows for long term storage of intermittent resources and diversifies energy carriers. These are real benefits that should not be ignored. However, for the specific case of decarbonizing residential space and water heating, decarbonized gas has severe limitations. Biogas, hydrogen and synthetic methane cannot be produced at a large enough scale to serve anything but a small fraction of our current natural gas demands. While diversifying our decarbonization strategies might lower risk, diversifying with P2G with high/uncertain costs and uncertain biomass availability might be higher risk overall. Efforts by the natural gas industry to show the potential of decarbonizing natural gas should not distract us from focusing on more feasible pathways of decarbonization, such as electrification.

Electrification

Electrification of the residential space and water heating sector would mean transitioning existing natural gas furnaces, boilers, and water heaters to electric resistance or heat pump systems. Resistance water heaters are much less efficient but much lower cost. It is possible that in some niche space heating applications with very few hours of operation these would be suitable. But in most cases heat pump systems would be more economical, particularly in areas with higher electricity costs.

Is there enough? Unlike the options above, there is no hard constraint on the electrification since more generation capacity can be installed. For the purposes of this discussion, the potential resource is effectively unlimited. Some electrification could even be done without additional infrastructure (this is covered in greater detail in the next chapter).

How much would it cost? The cost of electrification depends on the relative prices of gas and electric appliances and the relative costs of gas and electricity. Currently, in Pacific Gas and Electric territory, the relative costs of gas and electricity favor gas heating on an operational basis. The capital costs of efficient heat pumps are also higher than most gas furnaces and water heaters. We will take a deeper dive into this topic in Chapter 4, but to preview the results, electrification of heating would require a carbon price in the range of \$100-150/ton CO_2.

What is the best end use of this resource? The potential for new renewable electricity generation is far greater than what we would actually need, so if we choose the electrification path, we will not hit a hard supply limit. There certainly will be cheaper carbon abatement opportunities, and some of those should be taken up first, while being mindful about path dependence. Meeting climate goals is not simply a matter of working your way up a carbon abatement supply curve until a goal is reached. Doing so might lead to investments in slightly more efficient gas appliances that would then have to be replaced in order to meet a more aggressive reduction target.

1.4 Emissions impacts of alternatives

So far we have not discussed the emissions impacts of the different decarbonization options. Instead, we assumed that synthetic methane, biogas, and hydrogen were all effectively zero emissions. This is not the case in reality. Biogas and aggressively expanded biomass production would have environmental and emissions impacts from land use change and leakage of methane. Synthetic methane produced from electricity other than excess renewables would have emissions related to the production, operation, maintenance, and end of life of the generation capacity. Synthetic methane also may have emissions related to leakage. Because we did not account for these emissions, the cost per ton estimates can be considered a lower bound. The true emissions impact of biogas, hydrogen, and synthetic methane are outside the scope of this chapter. The emissions from energy efficiency and the solar fraction of solar water heating can be considered negligible.

We can however evaluate in greater depth the emissions that would result from electrification. Encouraging electrification prematurely could have negative consequences if the electric grid is not yet clean enough. When the marginal generator during times of space/water heating is above a 32% efficient natural gas generator, we would be better off switching to a heat pump with an energy factor (EF) of 3 vs a 96% efficient natural gas furnace. California is already there, but not all of the US is. While electrification delivers lower emissions with cleaner generation, the emissions attributable to the new electric load are not zero.

Understanding the emissions impact of electrification requires a better understanding of what emissions would reasonably be attributable to a new electric appliance. Depending on the time frame of study, we could reasonably come up with widely different answers. Over the very short term, if one were to add a new electric load that the utility had not forecasted, the most likely outcome would be that, if one were in California, a natural gas plant (or a collection of them) would consume slightly more fuel and have slightly higher emissions. These plants that increase their output are probably higher in the loading order, more expensive to operate, and less efficient. The emissions over this time frame would be the short-run operational marginal emissions. Depending on location, time of day, season, and existing load the short-run operational marginal emissions can vary widely. For example, in the Midwest (MRO), during periods of low demand, the marginal emissions may be over 900 kg CO_2/MWh (with an average of 834 kg CO_2/MWh), while in the west (WECC) the marginal emissions are half of that (486 kg CO_2/MWh average marginal emissions 2006-2011) [46]. This is because in the Midwest, a coal generator is on margin during low load hours. Graff Zivin et al. estimated slightly different emission factors in WECC, ranging from 300-400 kg CO_2/MWh depending on time of day [47]. They also found a US average of about 550 kg CO_2/MWh marginal emission rate.

Over a slightly longer time horizon, after these new electric loads have been observed for many days, the utility or system operator might now expect these loads to use electricity at certain times. If these loads are forecasted, then different generators may be dispatched to serve them. These would probably be cheaper to operate and possibly cleaner. The emissions impact over this time frame could be considered the long-run, operational marginal emissions.

As we think about a time frame at which generation capacity is planned and constructed, new electric loads from space and water heating could lead to a different decisions about what generation capacity to install. Over this time scale, the emissions impact of electrification is related to both the decisions that were made about what generators to construct and how all generators operate. Over this time scale, the "build" marginal emissions rate is a more meaningful measure of the emissions impact of new load. The short-run operational marginal emissions are not a good measure because some of those plants would be on the margin even if load was much higher. The metric that policymakers should consider is the change in emissions that would result from a long-term change in load. Hawkes et al. studied the marginal emissions of new loads in the UK, and found that, under a carbon tax or carbon constraint policy, the marginal emissions fell to approximately zero over time [48].

While estimating the specific marginal emissions of a particular new load over the coming decades is outside of the scope of this study, in Figure 1.5 we do show the range of emissions (y-axis) that would result from various generator types operating on the margin (x-axis). We find that, heat pump water heaters would have lower emissions than efficient, tankless condensing gas water heaters and are approximately equal to gas heat pumps running on 10% zero carbon synthetic methane using the WECC marginal emissions found in [47]. Over time, the trend will be a shift to the left, if the generation mix shifts toward renewables. The emission rates for different gas plant types are based on a 30-45% efficient gas generator, with the renewable range being made up by a 45% generator providing the remaining generation. Gas generator efficiencies are based on average tested heat rates of gas turbines and combined cycle generators from 2015. Coal generator emissions are based on coal steam plant average efficiency in 2015 using EIA emissions coefficients [33, 49]. In theory, more efficient plants are possible; both Siemens and GE offer combined cycle generators that are over 60% efficient [50, 51], which would be equivalent to about 300 kg CO_2/MWh in Figure 1.5.

The climate benefits that electrification provides in California are real and increasing. Since California has a Renewable Portfolio Standard (RPS), we can assume that new loads would have to be served by at least the RPS percentage of renewables. Without knowing precisely the type of remaining generators, we can safely assume that electrifying loads will reduce emissions immediately as long as generation is not coming from coal. Since electricity is going to become cleaner over the coming decades because of the RPS, the emissions benefit will increase. An electric heat pump installed today will have lower emissions year over year. Choosing a more efficient gas water heater or furnace will have the same benefit year after year, but choosing to electrify will create a larger and larger emissions reduction each year as the generation mix becomes cleaner. Such accelerating carbon reductions are what we need to meet aggressive long-term goals. Efficiency increases of gas water heaters and furnaces are also bounded by quickly approaching thermodynamic limits, and the potential savings that could result from those appliance level efficiency gains are nowhere close to the level of savings that we would need to meet emissions goals. While heat pumps also have efficiency limits, the potential savings are far greater. With enough clean electricity, practically all emissions from space and water heating could be eliminated. Money spent on more efficient gas appliances may be better spent on electrification. Similarly, the environmental benefit of an additional PV system on the grid will decrease over time, as the electricity that it is displacing gets cleaner and cleaner. However, the benefit of electrification increases. You can see this graphically in Figure 1.5. As you move to the left, the difference between the blue and green lines stays constant while the difference between the blue and orange lines increases. Electrification delivers increasing emission reductions over time.

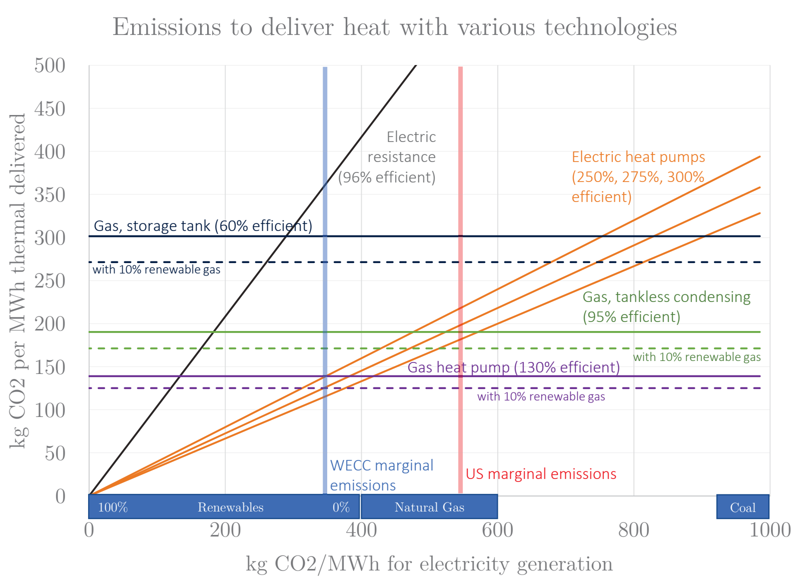

Figure 1.5: Emissions of various heating technologies as electricity emissions change.

1.5 Challenges and potential unintended consequences of electrification

The electrification of heating loads holds great promise, though we must also recognize the challenges or unintended consequences of this transition. Today, air conditioning systems use refrigerants with very high global warming potential (GWP). One common refrigerant, R-410a, has a GWP of over 2000. A typical central air conditioning unit might have 5 kg of refrigerant. If we assume that a central heat pump space heater has a similar quantity of refrigerant and that all of this refrigerant escapes over the 15-year life of the unit, then the climate impact from refrigerant leakage alone would be 70% of the CO_2 emissions from burning natural gas, even if the heat pump is using only clean electricity[3]. This could be considered close to the upper limit for the impact that refrigerant leakage might have. Most home air conditioners/heat pumps would contain less than 5 kg of refrigerant. Additionally, heat pump water heaters contain far less refrigerant (<1/2 kg) and are factory sealed, lowering the chance of leakage. Electricity is assumed to be emission free in this scenario, but if it were not then the heat pump could lead to higher emissions when leakage is accounted for. Natural gas leakage is also an important issue and is not accounted for in this example. Transitions to low GWP refrigerants, already underway, and monitoring/maintenance/takeback programs will be important to avoid unintended consequences of electrification programs. Without paying attention to refrigerant leakage, most of the potential benefit of electrified heating could be lost. New heat pump technologies are becoming commercialized that use CO_2 as the refrigerant, however these systems are still expensive.

Other concerns regarding heat pumps are that they perform worse at colder outdoor temperatures. New cold-climate space conditioning heat pumps are emerging that have COPs well over 2 even at below freezing temperatures [52]. Some models perform with COPs up to 2.9 even when the outside temperature is 5F. Heat pump water heaters also are noisier than other water heaters and are generally located inside the house so noise may be more of an issue than with split space conditioning systems. Very quiet split heat pumps water heaters are also on the market. There is also some transition cost for some houses if an upgrade to the electrical service is required. This upgrade should be coordinated with other activities, such as installing electric vehicle charging. This will be discussed in greater detail in Chapter 4.

[3]Assuming that 200 therms (21 GJ) of natural gas are used for space heating annually and produce emissions of 5 kg CO_2/therm, resulting in 1000 kg CO_2/year with natural gas heating. The emissions from leakage of 0.34 kg/year of R-410a, with a GWP of 2088, would result in the equivalent emissions of 710 CO_2/year.

The heat pump is the key piece of the residential heating decarbonization puzzle. If consumers are offered a reliable, durable, affordable, and high-performing heat pump then electrification is the clear path to decarbonize space and water heating because of the triple efficiency gain compared to resistance heating. Without heat pumps, decarbonization goals will be more difficult to achieve and will rely on solar water heating or decarbonized gas, with existing forced air systems being served by decarbonized gas, and hot water heating served by solar water heaters.

While space and water heating make up the bulk of current residential natural gas use in California, other uses such as clothes drying and cooking also need to be addressed. Gas dryers can be inexpensively replaced by electric resistance dryers– and eventually even those would be lower emissions than gas dryers. Heat pump dryers come with about a $1000 premium over electric resistance dryers, and without substantial cost reductions, these would not be cost effective. Emerging ultrasonic clothes dryers, while still in the lab, could potentially reduce drying energy use by 70% [53].

A potentially bigger point of resistance may be transitioning to electric cooking appliances like induction cooktops. People have strong attachments to gas cooktops, and strongly prefer them to electric resistance because of the instant heat and finer control. While induction cooktops provide some of these same benefits and high efficiency, they have a small market share and require particular cookware to work. Costs of induction cooktops are dropping quickly, so there may be some promise. Tackling cooking will be important if consumers ever consider disconnecting from the gas utility entirely. If other larger loads like space and water heating are electrified, the cost of providing gas for remaining end uses will likely increase in order to cover the fixed costs of gas infrastructure. We would expect that if the cost of providing gas for only cooking were to rise high enough then customers would defect either to bottled gas for cooking or transition to new induction cooktops.

1.6 Conclusion

In order to decarbonize the residential space and water heating sector in California, electrification appears to be the most promising path forward. Table 1.1 shows how the different decarbonization options compare along different dimensions.

Electrification provides both the cheapest decarbonization option and can potentially decarbonize all emissions from space heating if electricity is clean enough. Both synthetic methane from excess renewables or biogas suffer from low potentials and high costs. Solar thermal does provide immediate decarbonization for a large fraction of the emissions, but it is less cost effective than electrification, even when the cost

Table 1.1: Summary of decarbonization options

Option	**Potential reduction**	**$/ton CO_2**
Solar thermal	70%	$200
Biogas	20%	$300
Synthetic methane	2%	$500-1000+
Electrification	100%	$100-150

of renewables are accounted for. This is largely due to the decrease in cost of PV systems and persistent high cost of solar water heating systems. Biogas is infeasible on a nationwide basis, simply because the potential biomass resource is not large enough. The resource that does exist would be put to better use to decarbonize other end uses. Finally, synthetic natural gas comes with a high cost and large system efficiency penalty relative to electrification.

The purpose of this chapter was to outline why electrification is the most promising path to decarbonize and to provide motivation for the work in the coming chapters of this dissertation. Electrification also comes with several challenges. While more feasible and less expensive than the other options, it is more expensive than business as usual and does require actions from millions of building owners. The impact on gas utilities would be enormous, and we can expect stiff resistance from them on any policies that favor electrification. May the best fuel win.

Chapter 2

Implications of electrifying residential space and water heating

Preface

In this chapter, I present a model to estimate new electricity loads that would result from electrifying space and water heating systems in California. Using hourly electricity data, daily natural gas consumption data, and outdoor temperature I estimate when gas is being used for space heating. I disaggregate when gas is being used for space heating, water heating, and other loads. I use this information to estimate what new electric loads might look like in the residential sector and across the entire territory of a utility. I performed this work with the guidance of my advisor, Duncan Callaway. An earlier version of this work was presented at the 2016 ACEEE Summer Study. I wish to thank Michaelangelo Tabone for insightful conversations, as well as Peter Alstone and Sam Borgeson for sharing computing resources helpful in pursuing this project.

Chapter Abstract

Meeting aggressive emission reduction goals will require residential space and water heating systems to transition to cleaner fuels. Electrification is a promising method to reduce emissions, but in order to gain support from policymakers, system operators, and utilities we need to better understand what impacts electrification of space and water heating would have on the grid. The electricity grid needs to be prepared for the additional load, and in order to do that we need to better understand the characteristics of new heating loads. In this chapter we present a new method for estimating hourly residential space heating and water heating demand using hourly electricity consumption data (smart meter data) and daily natural gas data. We use a dataset of 30,000 customer accounts in Northern California and apply linear regression at both the individual house level and to hourly, climate-band-averaged whole-home electricity consumption, climate-band-averaged whole-home gas consumption, and outdoor air temperature data to determine both the hours when heating is more active and the outdoor temperature dependence of that consumption. This varying temperature responsiveness allows us to assign varying amounts of space heating load to different hours. We then scale up the results to the entire utility service area to show when and where electric heating will impact peak demand. We find that about 1/2 of the residential space and water heating gas use could be electrified without any impact on peak demand. We also find that electrification of space and water heating would increase the load factor by at least 5%—and even more if heating loads are controllable. While electrification of heating would have little impact on peak demand on a systemwide basis (until very high penetration), at the distribution level electrifying heating loads may have an impact on peak demand for feeders that are mostly residential.

2.1 Introduction

Background

In order to meet aggressive emissions reduction goals over the coming decades, the energy system will need to undergo a widespread transformation. Past potential studies have indicated that meeting this goal is possible, though they also consistently include substantially reducing or eliminating direct emissions from residential space and water heating as a necessary measure [2, 3, 4, 5, 6, 7]. While this is necessary to meet these goals, so far we lack the policies that will encourage a transition away from combustion of fossil fuels in homes. The emissions reduction that will come from buildings will likely be even greater than the 80% economy-wide reduction that will be necessary to limit warming to a safe level, since some sectors are more difficult and costly to decarbonize than others. The Deep Decarbonization Pathways Project suggests that for the US to reduce emissions 80% below 1990 levels by 2050, much larger reductions must come from the residential sector, with reductions ranging from 89-98%, depending on the scenario [4].

Today in California, natural gas is the main energy source for residential space and water heating, and made up 82% of space heating systems and 75% of water heating systems according to recent estimates [17]. Of the 354 therms of natural gas consumed per household with natural gas service, 49% was used for water heating and 37% was used for space heating [17]. Direct combustion in homes in California represents 6% of emissions, or about 24 million tons of CO_2 [16].

Electrification has the potential to be the most promising strategy to decarbonize the space and water heating sector because of both the potential larger scale and lower cost compared to other alternatives. Electrified heating with very efficient heat pumps can have lower emissions than efficient gas furnaces and water heaters, even if the electricity is coming entirely from natural gas. While the common perception is that natural gas space and water heating systems have a higher system efficiency than their electric counterparts, this is now false. Heat pumps now make the electric option more efficient from a whole-system perspective. As renewables make up a larger part of the generation mix, electrification becomes even cleaner.

In addition to decarbonization, electrification has other benefits for the energy system. Since California is a summer-peaking system, electricity infrastructure can be better utilized with additional winter loads, as we will show in this chapter. With proper control, electrified space and water heating can be useful for integrating large fractions of renewable energy on the grid. As the fraction of variable and uncertain renewable generation increases, more flexibility from electricity loads to maintain balance will be needed. Buildings naturally store energy in their indoor air, thermal mass, and hot water supply. This inherent storage means these loads can be flexible in when they consume electricity [54, 55].

In order to fully evaluate electrification as an option to decarbonize the residential space and water heating sector, we need to understand the characteristics of the new electric loads that would result from fuel switching. In this chapter we answer the questions: What will residential electricity load shapes look like post-electrification? How will electrification impact peak demand and load factor? Does electric space or water heating have a bigger impact on peak demand, and in which climates are these impacts largest? If these loads are to be electrified to meet climate goals, utilities need to be prepared for these new loads, particularly if they cause an increase in peak demand or exacerbate ramping challenges.

Prior work

Electrification of residential space and water heating has, so far, been an understudied area when it comes to climate solutions, but other prior work has surveyed how energy is used in buildings and disaggregated energy use to energy services. This study builds on past studies that have surveyed large numbers of households with the goal of disaggregating energy use into different end uses. The nationwide Residential Energy Consumption Survey (RECS) [56] and the California Residential Appliance Saturation Study [17] are two such studies that use large surveys about the characteristics of buildings and their occupants and energy use to determine how much energy is being used for different end uses. These studies however only estimate energy use at annual timescales. These large-sample survey studies are expensive to conduct, but they do provide meaningful information about the types of appliances in peoples homes and the general breakdown of energy use. Prior work by Nadel et al. have shown, using RECS data, the potential for energy savings by switching from gas furnaces or electric resistance heating to electric heat pumps [57, 58].

This study also builds on work at Princeton dating back almost 40 years which measured, in great detail, energy use in residential townhouses in New Jersey [59]. Some of the methods developed almost 20 years ago as part of the Princeton Scorekeeping Method (PRISM) controls for different weather conditions when looking at energy use of a building [60]. We use some of the same models to determine when space heating operates that were based on Kissock's inverse modeling work [61].

Borgeson demonstrated several methods of analysis that could be performed on a large and representative sample for an entire utility service territory [62]. This study uses one of the same datasets he used, and many of the data processing tools developed by Borgeson were used in this analysis.

Finally, there has been interest in the UK on how electrification would impact electric loads. While past UK research has also predominantly relied on daily data, they do show that electrifying gas end uses can add to the variability of electricity demand and increase peak demand [63, 64, 65].

Gaps

There is a body of literature that looks at future scenarios of renewables penetration, optimization of renewables and transmission portfolios, and potential studies of what is possible to drastically reduce carbon emissions. Heating electrification is a lever consistently used across studies to meet Californias deep decarbonization goal of 80% below 1990 levels by 2050, but this prior work has not taken an empirical approach in estimating what the new electrical heating loads would be. Existing studies rather rely on a small set of representative building energy models to create hourly load profiles, or they use very coarse load profiles [2]. The empirical approach offered here has the potential to not only account for the thermal properties of buildings but also human behavior.

While prior work has been very important to show what is possible in terms of deeply reducing carbon emissions, a large gap remains in understanding how we might actually arrive at a decarbonized future. In order to design policies that might support the various transitions necessary we need to know, in greater detail, what new loads would look like. Both the shape and magnitude of these new loads will impact the cost of decarbonization, and we aimed to quantify both as a part of this study.

Contribution

Our goal is twofold. First we estimate the magnitude, timing and shape of new loads in different climates in PG&E territory, and second we examine, at a system level, what the new loads would be.

Planning electricity infrastructure requires an understanding of electricity demands on an hourly or sub-hourly time resolution. Over the course of a day, we would like to know when new electric heating would operate and how they would impact total system load. New smart meter infrastructure makes it possible to observe 15 minute or hourly patterns of electricity use. In central heating systems, furnace fan operation is correlated with gas consumption of the furnace. We use this relationship to identify hours when gas is being consumed.

In 2015 there were about 65 million smart meters installed in the US, with 57 million of those in the residential sector. The data from these widely deployed devices make it possible to perform analyses on large numbers of households that previously would have been far too costly [66]. Without interval meter data from a large, representative population, studies relied on engineering models to determine when energy would be used by different appliances. The challenge is that engineering models are known to poorly capture how energy is used in real buildings by real occupants. The engineering models may not accurately capture schedules of real occupants, actual temperature setpoints, thermal mass, orientation, or actual building tightness.

From a planning perspective we are interested in how a large portfolio of buildings performs and how the portfolio might perform with some intervention. An engineering model could be useful, for a single building, to show how some design change could impact energy use for that building. But constructing engineering and behavior models for every building is infeasible; however, looking at actual performance of a large collection of buildings can give us insight into the behavior and physical attributes of buildings.

In this chapter we present a method to estimate building-level changes in hourly electricity demand that will result from a transition to electric space and water heating. With access to data from 30,000 anonymous residential customers from Pacific Gas and Electric (PG&E) and zip code level outdoor temperature, we have developed a model that estimates how buildings (and their occupants) respond to outdoor temperatures over the course of the day at different temperatures. We use these estimates, along with assumptions about efficiencies of current and future heating appliances to estimate new hourly load profiles. We estimate when gas is currently used for space heating and estimate future heating electricity demands. To estimate the hourly natural gas use for heating, we make use of information that exists in the hourly electricity data. This empirical approach is grounded in current patterns of energy use from many customers and offers an alternative way to model a future with electrified heating.

We find that space heating and water heating will both increase morning and evening peaks for residential buildings. As a result we would expect that morning and evening ramps may be exacerbated if new space and water heating loads are not intelligently controlled. We find that almost 1/2 of residential gas consumption for space and water heating could be eliminated without adding to peak demand in PG&E territory. Electrifying all residential space and water heating would increase load factor by at least 5%—more if loads are intelligently controlled. Increasing load factor better utilizes generation assets and can potentially lead to lower electricity prices for consumers. We also show how a coarse control strategy on water heating of only 1/3 of houses could further increase load factor by an additional 1%.

If fuel switching from natural gas to electricity occurs at a large scale, the grid needs to be prepared for the additional load. Studies such as this are important to characterize what those future load shapes might be. The outcome of this study can be used to better quantify the total cost (or savings) that result from electrifying residential heating. This study also begins to quantify the need for new generation to support these new loads and the need for fast-moving generation or demand response to deal with ramping issues that will become more challenging with higher renewables penetration.

2.2 Data

The analysis in this chapter was possible because of data that was provided by Pacific Gas and Electric via the Wharton Business School's Customer Analytics Initiative. The dataset consists for 30,000 customers split evenly between three geographic zones

(Coastal, Inland Hills, and Central Valley). Since this study is focused specifically on customers who use natural gas for heating, we primarily focus on those customers who have both gas and electricity data available. Each customer account is associated with a premise and one or more service points. A premise is a home, and a service point is a connection to either gas or electricity. While the dataset contains 30,000 customers, there are 37,582 premises in the dataset. We treat the service point as the unit of analysis and match gas and electric service points that serve the same customer.

These data make it possible to observe when consumers are using electricity, not just how much they are use over a month. We use these patterns of electricity use to predict when gas also is being used. For a home that has a central heating system, the furnace fan will operate as gas is being consumed. The coincident use of electricity and gas when heating occurs, along with correlation of heating with outdoor temperature allows us to estimate how much heating occurs in each hour.

For code compliance, buildings are evaluated by engineers using energy models in the design process. Depending on which of the 16 climate zones they fall into, using the California Energy Commission map, they may have different quantities of allowable (modeled) energy use. Unfortunately these climate zones do not map directly to utility territories. In order to simplify the systemwide analysis, we use 10 climate bands specified by PG&E as shown in Figure 2.1 [67]. We also map PG&E zip codes to climate bands using PG&E data [68]. This is necessary, since we would like to know the total number of PG&E households that fall into each climate band. We use the zip code to climate band mapping, with census data to determine the total number of households in each climate band. We used the American Community Survey 5-year average from 2015 via SocialExplorer to determine the number of households per zip code [69].

Using the census data and zip code mapping we find total number of households per PG&E climate band, as shown in Table 2.1. However, what we are ultimately interested in are the number of houses that currently have gas (and use it for space and water heating) and are also served by PG&E for electricity, known as dual fuel customers. The Wharton dataset shows if each premise is gas only, electric only, or dual fuel. We assume that the Wharton dataset is representative in the approximate breakdowns of meter types by climate band. We calculate the fraction (in the Wharton dataset) that are dual fuel customers relative to all customers (dual+electric only+gas only customers) and then estimate the total number of dual fuel households by climate band using this fraction. This may be an underestimate of the total number of households that would electrify, as some customers that present as electric-only might actually have gas service from other means (such as a central meter in a multifamily building or bottled gas).

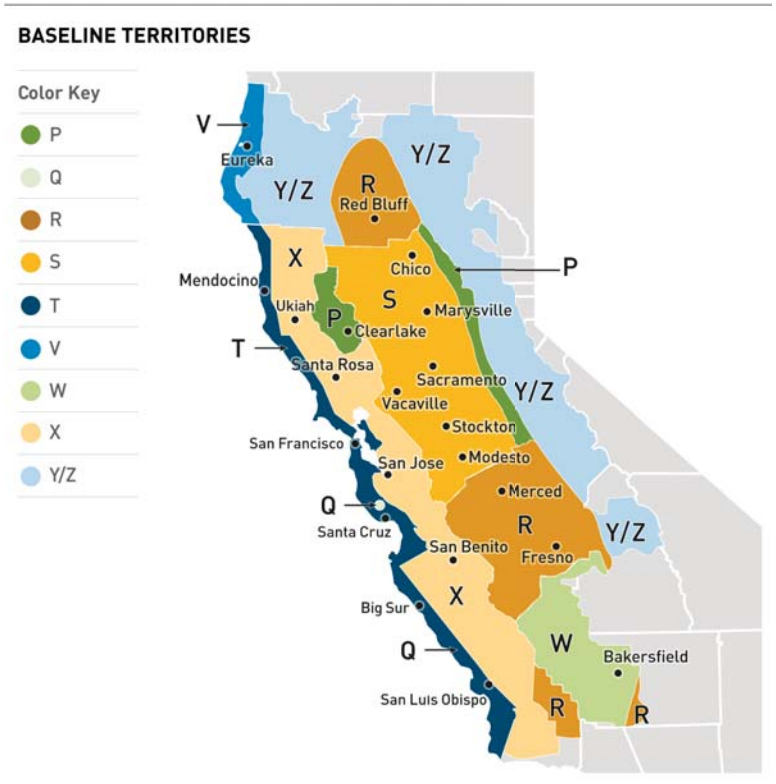

Figure 2.1: Map of Pacific Gas and Electric Climate Bands

We assume that all households have electric service from some provider, but we estimate new electric loads only for PG&E customers. In some areas, such as climate band S, there are many households with gas only service. This is because customers' electric service might be provided by another utility.

After accounting for the dual fuel fraction, we found a total estimate of 3.5 million residential dual fuel residential customers. We find this estimate reasonable, since PG&E has 4.3 million gas customer accounts including many gas only customers in Sacramento [70]. We also compare the total number of "premises" in the Wharton dataset to the census population.

In this study we estimate how energy use responds to outdoor temperature. That relationship requires high quality weather data for each of the locations where we have energy data. House location was known at the zipcode level. For each zip code we determined the latitude and longitude of the center of the zip code via the CivicSpace US ZIP Code Database [71]. With the latitude and longitude, we looked

Table 2.1: Households by climate bands

Climate Band	Census Households	Dual Fuel Fraction	Dual Fuel Households	Premise count in Dataset	Fraction of total population in Dataset
P	148,159	13%	18,931	840	0.57%
Q	3,053	0%	0	35	1.15%
R	544,361	61%	332,931	2937	0.54%
S	1,466,684	45%	661,106	7674	0.52%
T	1,132,721	70%	787,497	11396	1.01%
V	47,893	80%	38,358	508	1.06%
W	326,573	49%	159,344	1278	0.39%
X	1,824,016	80%	1,461,878	12234	0.67%
Y	58,062	4%	2,453	343	0.59%
Z	1,920	0%	0	44	2.29%
Total	5,553,442		3,462,499	37289	0.67%

up the weather for that location via the Forecast.io API which returned the hourly outdoor temperature, sunrise and sunset times, and many other readings that were not used [72]. No further validation was performed on the Forecast.io data, though we also did not encounter missing or abnormal readings for the locations that were included.

Finally, we also compare our estimates for new residential loads with the total system demand for all of PG&E. In order obtain the total system demand we use data from California Independent System Operator Open Access Same-time Information System (OASIS) [73]. We use “Actual” 2011 data from the CAISO system demand forecast in OASIS for PG&E. We chose to evaluate 2012, as this was the year that had the most smart meter data available.

2.3 Methods

We use daily natural gas meter data together with hourly electricity use, with assumptions about the efficiency of existing gas and new electric space and water heating appliances, to estimate what the new electric loads would be if space and water heating are electrified. If hourly residential gas usage were available, this would be a trivial task. However, only daily residential natural gas consumption data is available in approximately 1 therm resolution. In order to form this estimation, we first process data on an individual-house basis (matched gas and electric service points) to determine how gas use responds to temperature. Processing individual houses lets us build a set of houses that have complete data.

We make three key assumptions. First, from a planning perspective, the load of an individual house may not be important other than for sizing that single house's connection. The average load of many houses on a feeder or in a larger service area may, however, impact larger infrastructure needs such as distribution, transmission, and generation capacity. With this relaxed focus on averages and not individuals, we average energy use over a climate band to determine how the average house in a climate band responds to temperature. Since gas data is available at only 1 therm resolution, averaging across houses smoothes out gas usage. Second, we make the assumption that it is not the hourly outdoor temperature that directly drives space heating loads, but rather the time of day together with the average outdoor daily temperature over the previous 24 hours. Using the 24-hour moving average temperature is a coarse way of taking into account higher-order thermal dynamics in buildings and the effects of human behavior such as set-point changes or occupant driven heat gains. Third, while we include only those houses that have both natural gas and electricity service, we also assume that consumers either use natural gas for heating or that their pattern of electric heating is the same as their pattern of gas heating.

While we are predominantly interested in regional averages, we estimate new electric loads both for individual houses and for the climate band average. Processing data at an individual household level gives a sense of the distribution of responses across houses. The regressions models used for individual houses and the climate band average are identical.

An overview of the way we process data is shown in Figure 2.2. The individual steps will be outlined in the following sections.

Space Heating Methodology

Step 1: Estimate changepoint using gas data

The first step in the model is to determine the changepoint—the daily average temperature at which heating turns on—for each individual household. We do this by performing a piecewise regression where daily gas use is regressed onto outdoor daily average temperature, fitting separate coefficients for periods when outdoor temperature is above or below a changepoint temperature. The changepoint selected minimizes the sum of squared errors of predictions [74].

To illustrate this, we show average gas use for houses in climate band 'S' in Figure 2.3. Performing a piecewise regression, we fit two lines and identify the changepoint. At higher temperatures, gas use is made up mostly by water heating, cooking, and clothes drying. Above the changepoint gas use is less responsive to

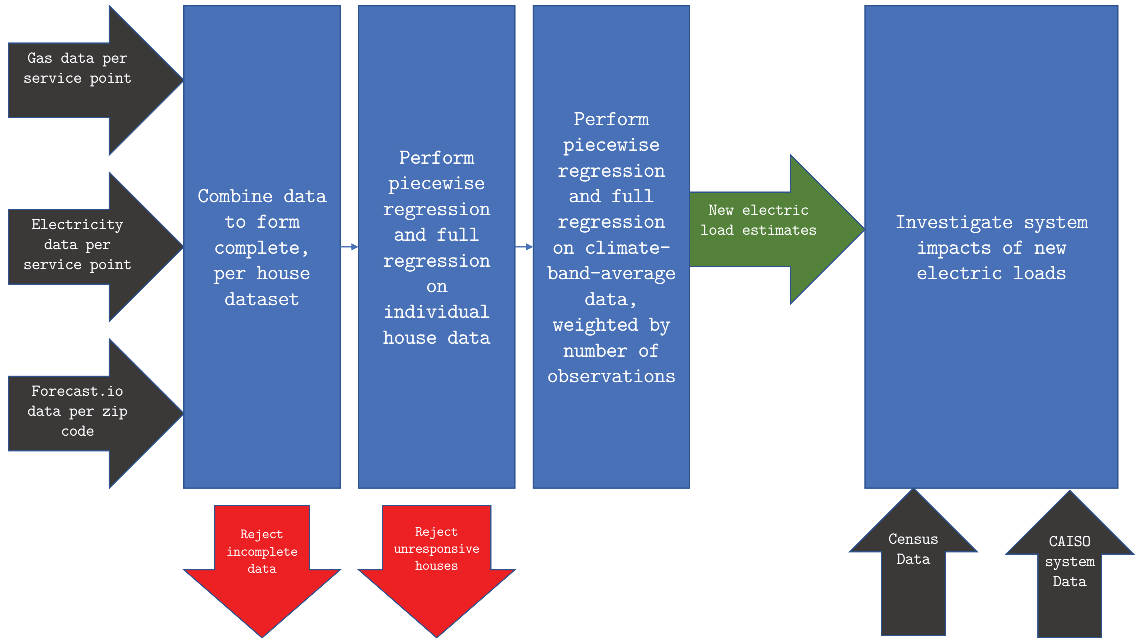

Figure 2.2: Schematic of data processing

outdoor temperature because energy use for services such as cooking and clothes drying are not strongly correlated with outdoor temperature. Water heaters, dryers, and stoves need to be electrified to reduce emissions from this portion of household gas use. The slope is not zero, however, because water heating energy is higher at lower temperatures. This is because incoming water is colder and needs to be heated more and there also are higher heat losses in hot water distribution inside the home as the outdoor temperature drops. Below the changepoint, space heating also accounts for much of the gas use.

Step 2: Estimate daily temperature responsiveness of gas consumption

The piecewise regression, shown in Equation 2.1, identifies the changepoint and fits slopes above and below the changepoint, β_{above} and β_{below}, as well as an intercept. We wish to use the results from the piecewise regression to estimate how much gas is used for water and space heating each day. Equations 2.2 and 2.3 show how to calculate those estimates. To calculate gas used for water heating, we use parameters directly from the piecewise regression. We expect that β_{above} would be negative showing lower gas use for water heating at higher outdoor temperatures. The changepoint is also another parameter that is identified, and it is used to calculate the Heating Degree Days (HDD) for each day. HDD is the difference between the average daily temperature and the changepoint. It is positive for temperatures below the changepoint and zero for temperatures above the changepoint.

To calculate the gas used for space heating, let us refer to difference in slopes as β_{gas}, or more explicitly $\beta_{above} - \beta below$. With this formulation, we expect β_{gas} to be positive and represents the number of therms of additional gas used for space heating, per Heating Degree Day. Therefore, the amount of gas used for space heating would be that shown in Equation 2.3. On warmer days, when HDD is zero, no gas is being used for space heating. Our estimates of β_{gas}, α_{above}, and β_{above}—along with the changepoint and daily average temperature—allow us to determine how much gas was used for space heating and how much gas was used for water heating on each day d.

$$gasUse(d) = \begin{cases} \alpha_{above} + \beta_{above} \times AvgTemp(d) & \text{if } AvgTemp(d) > changepoint \\ \alpha_{below} + \beta_{below} \times AvgTemp(d) & \text{if } AvgTemp(d) \leq changepoint \end{cases} \tag{2.1}$$

$$gasUse_{water}(d) = \alpha_{above} + \beta_{above} \times AvgTemp(d) \tag{2.2}$$

$$gasUse_{space}(d) = \beta_{gas} \times HDD(d) \tag{2.3}$$

Step 3: Remove houses with unresponsive gas use from analysis

Using the changepoint that is identified in this regression using the gas data, we apply it to electricity data to determine how electricity use increases as the daily average temperature drops below the changepoint. Heating Degree Days are calculated for each day of data using this changepoint. We then look at the distribution of gas and electricity responsiveness and notice the behavior that many houses are not responsive in their gas use to outside temperature as shown in Figure 2.4. Since these houses do not respond to temperature with their gas use, we exclude them in future analyses. We show the percent and total count of houses where gas use is unresponsive in Table 2.2. Climate bands T, V, and Y have notably high fractions of unresponsive houses, though climate band Y is due to the fact that there are so few houses in the dataset from that band. Climate band T has a very high fraction that are unresponsive and a very high count which suggests that many houses with gas service really do not respond to temperature with their gas consumption. We have

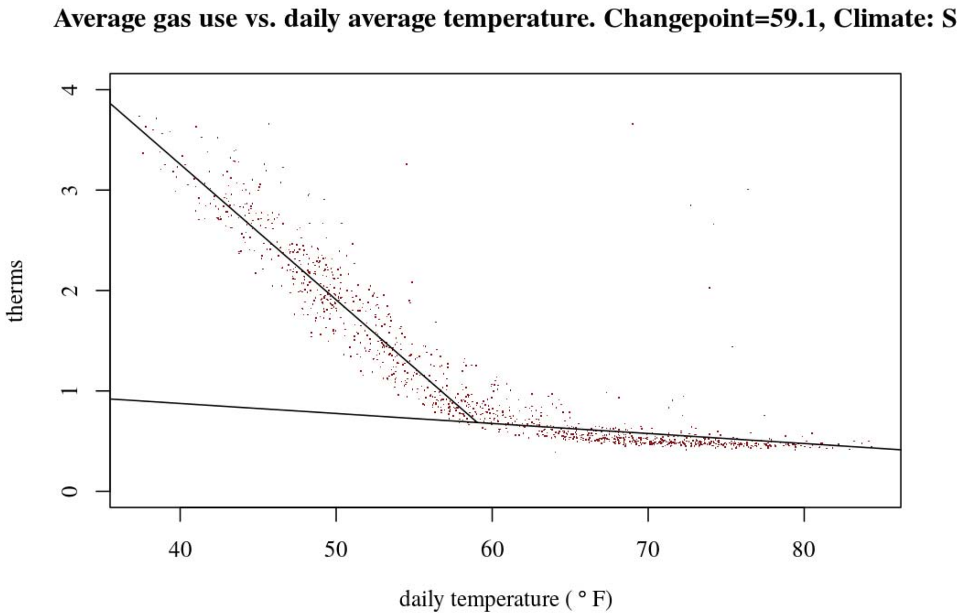

Figure 2.3: Gas use vs temperature in climate band 'S'

several hypotheses for why this might be the case. These houses may not use gas for space heating but still use gas for other services that do not correlate with outside temperature. They might receive space heating from a central plant on a different meter, or they might be unoccupied most of the time.

Climate Band	Percent unresponsive	Unresponsive count
P	7	6
R	9	160
S	10	336
T	25	1310
V	32	98
W	5	29
X	14	1110
Y	62	5

Table 2.2: Percentages of houses with gas use that does not respond to outside temperature.

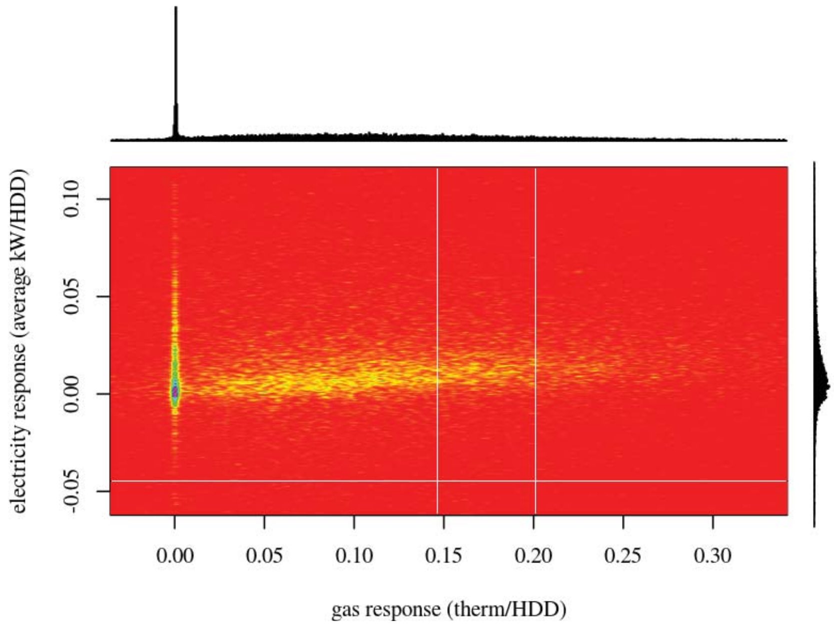

Figure 2.4: Histograms of gas and electricity responsiveness to outside temperature

Step 4: Estimate hourly temperature responsiveness of electricity consumption

We perform a regression both on individual houses and climate band averages, but the formulation is the same. The regression formulation is below in Equation 2.4 , where $y(t)$ is the hourly electricity use, $\alpha_{HOD,day}$ is an hourly fixed effect for each of the 24 hours of the day HOD and day types (weekday, weekend), and $\beta_{HOD,day}$ is an hourly temperature responsiveness coefficient, also for each of the 24 hours on weekdays and weekends. Heating degree days are calculated after identifying the changepoint using the natural gas data. Finally, $\gamma_{HOD,day}$ is a coefficient that shows how much electricity is used for lighting. $Dark(t)$ is a vector that indicates whether an hour is dark or not. It takes values between zero and one, so it can indicate if an hour was partially dark. This is based on sunrise and sunset times in the weather data. For hours that are either always dark (in the middle of the night) or always light (in the middle of the day) $Dark(t)$ has a value of zero to avoid collinearity with the fixed effects.

$$y(t) = \alpha_{HOD,day} + \beta_{HOD,day} HDD(t) + \gamma_{HOD,day} Dark(t) + \varepsilon \tag{2.4}$$

We perform this regression both on individual house data and using climate band average data. HDD is calculated hourly, using the past 24 hours of outside temperature data. Only those hours when HDD is greater than zero are included in the regression. We found that including slightly warmer days (for example, days that were only 5 degrees warmer than the changepoint) included some hours where cooling was likely occurring. Including these hours impacts the fixed effects, which in turn change the temperature responsiveness coefficients ($\beta_{HOD,day}$), which are the output of interest . They show, on days with heating, which hours are more temperature responsive in their electricity use.

For comparison, we also performed this analysis using hourly temperature data, rather than the 24-hour moving average temperature that is used above. This approach assumes that heating use responds mostly to the temperature in this hour, not the past day. The hourly approach gives us an estimate for how electricity use changes in each hour as the temperature (in each hour changes). This regression is shown in Equation 2.5. In order for comparison with results from Equation 2.4, we multiply the $\beta_{HOD,day}$ term by -1.

$$y(t) = \alpha_{HOD,day} + \beta_{HOD,day} Temp(t) + \gamma_{HOD,day} Dark(t) + \varepsilon \tag{2.5}$$

Step 5: Translate hourly temperature responsiveness of electricity and daily temperature responsiveness of gas into new electricity loads

Because we know the daily therms used per HDD from the piecewise regression (β_{gas}) and the temperature responsiveness of electricity for each hour, we can estimate the hourly gas use for space heating. ($\beta_{HOD,day}$) are normalized within each day type, so that the (β_{HOD}) estimates to sum to 1. In the rare event that a (β_{HOD}) term is negative, we adjust all terms by the minimum (β_{HOD}) value. In doing so, these normalized values will represent the proportion of total daily heating that will occur in each hour of the day for that type of day (weekday/weekend). In this way, the product of β_{gas}, HDD, and each normalized β_{HOD} would represent the hourly gas use. While this gives an estimate for the amount of gas that was used, we do not know precisely how much heat was delivered to the space. We need to make an assumption about the efficiency of the furnace in the existing house. In this study, we assume that the average furnace was 78% efficient The furnace efficiency is based on the Federal standard dating back to 1992 [75]. While some furnaces may exceed this standard, many are also not operating as efficiently as they were when new.

With assumptions about the efficiency of the existing appliances, we know how much heat is delivered to the space. With an assumption about the efficiency of the new electric equipment, we can convert the delivered heat back to electricity demand. For new electric heating appliances we assume space heating has a Heating Season Performance Factor of 8.5 (or an average COP of 2.5), which is the current Energy Star standard.

By adding the new estimate to the current, existing electricity use, we arrive at the new total hourly electricity demand. Existing temperature responsive electricity demands (such as resistance heating or furnace fans) are included in the existing electricity use.

Water Heating Methodology

Smart meter data unfortunately cannot assist us in estimating when gas is being used for water heating. Instead, we use our estimate for $gasUse_{water}(d)$ along with estimates that are used for Title 24 compliance to come up with hourly gas use for water heating. We use the hourly water heating schedule in the 2013 Residential ACM Reference Manual from the California Energy Commission to determine how energy use for hot water heating is split up over the day [76].

Similar to the process used for space heating, we make an assumption about the efficiency of the existing gas water heater. We assume that existing gas water heaters are 67% efficient, based on the Title 24 standard. This allows us to estimate the amount of energy that is delivered to the hot water tank. We then assume that the new electric water heater has an average COP of 2 which allows us to make an estimate of the new electric load for water heating. Almost all heat pump water heaters on the market today are more efficient than this standard. Using higher efficiencies would decrease the impacts on the electricity system that we see in the Results section.

Electric water heating has the potential for shifting load to periods when electricity is cheaper. In order to capture this flexibility potential, we also explore an alternative method based on a new water heating load shape that minimizes electricity costs rather than the schedule given in the 2013 Residential ACM Reference Manual. We developed a linear program that minimizes the annual electricity cost based on Time Dependent Valuation (TDV) subject to physical constraints of a typical water heater. TDV is an estimate of the full cost to deliver electricity each hour of the year [77].

The linear program assumes that the average temperature in the tank must stay between 124-150F and that draw patterns are the same as those given by the Title 24 reference manual, with energy equivalent to 38.4 gallons of 124F water being used daily. We effectively treat the tank as an energy storage device, and treat the draw schedule as an energy draw from the hot water tank. The amount of energy in the tank is bounded by the energy in a tank with 124F and 150F water. These bounds mean that hot water will always be available and that it is within the range that tanks can safely handle. During periods when the tank is hotter than than 124F, hot water would be mixed with cold water through a thermostatic mixing valve to provide 124F water. We treat the tank as a single mass, at a single temperature without the stratification that exists in real water heaters. We also use average draw patterns which are much flatter than actual draw patterns. These simplifications result in a model the approximates the average of all tanks, rather than a specific water heater's performance. While on average there would always be hot water available in the fleet of water heaters, there might be some water heaters without any hot water left at times. The linear program minimizes "spending" while maintaining comfort. We assume that the tank is 50 gallons and the heating system can deliver heat to the tank at a maximum rate of 1250W, which would be a typical 500W heat pump operating with a COP of 2.5. We assume that incoming water temperature is 55F and that total tank losses are unaffected by this change in control strategy (the additional losses that occur at 150F compared to 124F are not accounted for).

We model one year of hourly operation with our decision variable being the amount of energy delivered to heat water each hour. The energy in the tank at the end of the year must equal the energy in the tank at the start of the year. Energy in the zeroth hour is free to set the initial conditions of a hot tank at the start of a year. However, there is no net free energy provided, since total energy in the tank at the end of the simulation must equal energy in the tank at hour 1. Without setting these initial conditions we would see very high energy consumption in the first hours of the simulation, and this would not reflect typical operation.

$$\text{minimize} \sum_{t=0}^{8760} f_t x_t \tag{2.6}$$

Subject to:

$$0 \leq x_t \leq maxPower \tag{2.7}$$

$$minTankEnergy \leq e_t \leq maxTankEnergy \qquad \forall t \in 1,..,8760 \tag{2.8}$$

$$e_1 = e_{8760} \tag{2.9}$$

Where:

$$e_t = \sum_{j=1}^{t} (x_j - d_j)$$

x_t = thermal power of water heater at time t

f_t = cost of energy at time t, f_0=0

e_t = energy stored in tank at time t

d_t = energy drawn from tank at time t

We show how these shapes compare in Figure 2.5. While the linear program produces an hourly charging schedule using hourly TDV values, here we have averaged those into four categories for weekdays and weekends in the "summer" and "winter." Summer is defined as May through September. Those months were chosen to coincide with the super peaks in TDV. The "LP" plots show what the cost-minimizing loads would be using the linear program described above and the "Weekday" and "Weekend" plots show the average energy draw patterns without the linear program. In summer, we see lower water heating demand in late afternoon hours when air conditioning loads will be at their peak. In winter, when afternoon electricity "value" is lower, most heating occurs then. We will show how shifting these loads changes the total system demand in a later section.

2.4 Results

In this section we will present some of the results that show the shape of new space and water heating loads in different climate bands and the impact that these new loads will have on systemwide demand. We will focus on showing results from climate bands T and X as these have the highest populations in the dataset and, along with S, will drive much of the systemwide outcome. The results from the other climate bands is shown in Appendix A. We start with some results that come from processing data at the single-house level.

Results by individual house

First, we processed each service point in each climate zone for which gas, electricity, and weather data existed. This resulted in 19305 service points that could be analyzed. Using the piecewise regression method described earlier, we determined the changepoint. We found, on average the changepoint was 57F, significantly cooler than 65F that is typically used. This difference in changepoint could be due to houses in

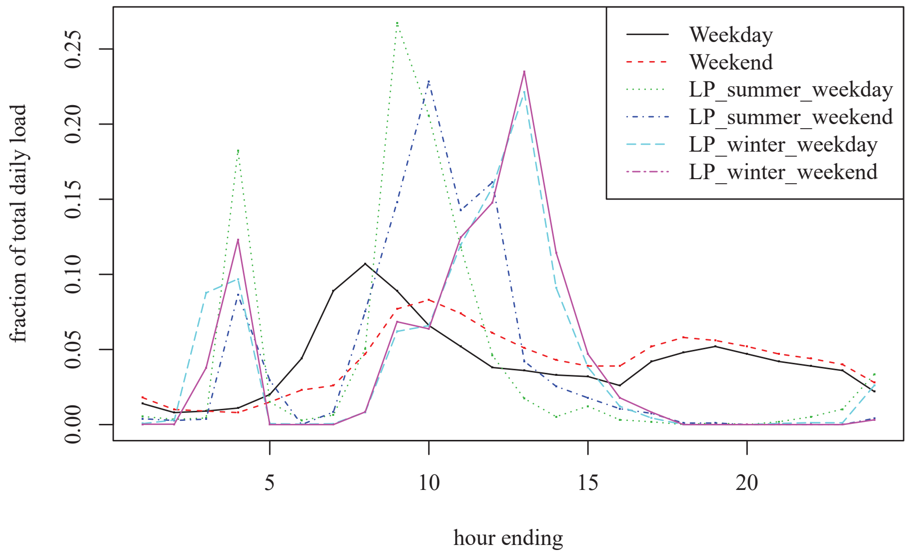

Figure 2.5: Water heating load shapes with and without control

California being more efficient than average or greater tolerance of occupants to colder indoor temperatures. The distribution of changepoints can be seen in Figure 2.6.

As we mentioned earlier, in Figure 2.4 some houses are not responsive to outside temperature in their gas consumption. We investigated those houses further, to see how the electricity responsiveness varies between houses that respond to outside temperature with their gas consumption and those that do not. As shown in Figure 2.7, houses that are responsive in their gas use are actually slightly more responsive with their electricity use. At first, we thought perhaps these unresponsive gas houses were actually heating with electricity, and that is why their gas use did not respond. However, that does not appear to be the case. These houses either are unheated, or are heated by gas on a separate meter. We make the assumption that all houses are heated—and therefore ignore the unresponsive houses in this analysis.

One of our main goals was to determine the relative temperature responses during different hours of the day. We run data from each individual house through the regression. The average estimates for $\beta_{HOD,Weekday}$ for each of the 24 hours of the day on weekdays are shown in Figure 2.8 and Figure 2.9 for climate bands T and X respectively. Remember that these coefficients are first normalized and then are used

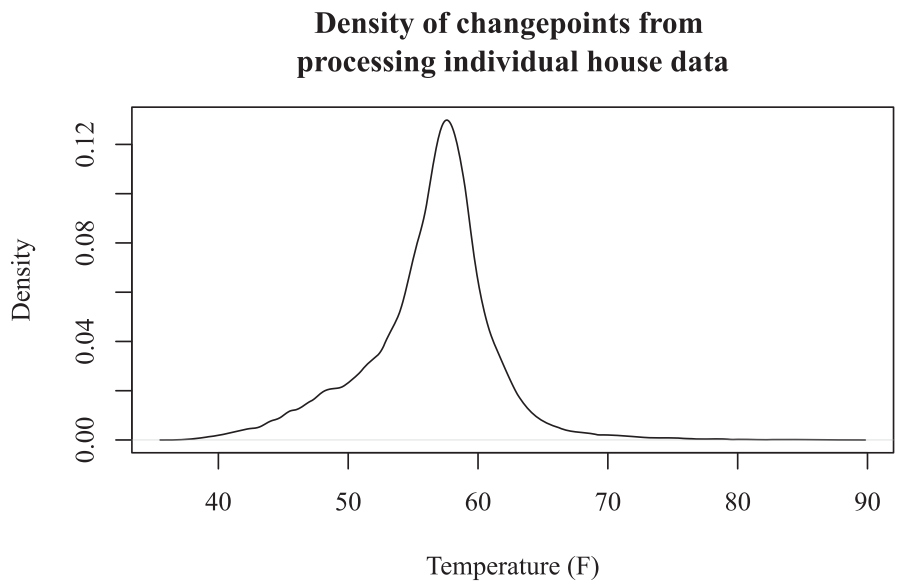

Figure 2.6: Distribution of changepoints

to divide predicted daily gas use among hours. We see similar responses between these two climate bands and a general trend of morning and evening heating with less heating mid-day. This is likely due to solar gains and/or unoccupied residential buildings during the middle of the day. While the coldest temperatures are overnight, according to these results, we expect less heating during overnight hours. This may be because of lower temperature setpoints overnight and buildings coasting through the late night hours.

Results by climate band average

We use the individual house regressions to both preprocess the data and identify those service points with complete data. The individual regressions also do give us some insight into the distributions of the estimates between houses. But, the ultimate goal is an estimate of the new total electric load across many houses. We use climate band average data to do this, which simplifies the computation (compared to running a single regression using all house-level data in a climate band). Using averaged data also smoothes out therm-resolution issues in the natural gas data. We will go through the step by step results of our estimation.

For the climate band average we estimate the changepoint, β_{gas}, β_{above} and α_{above}.

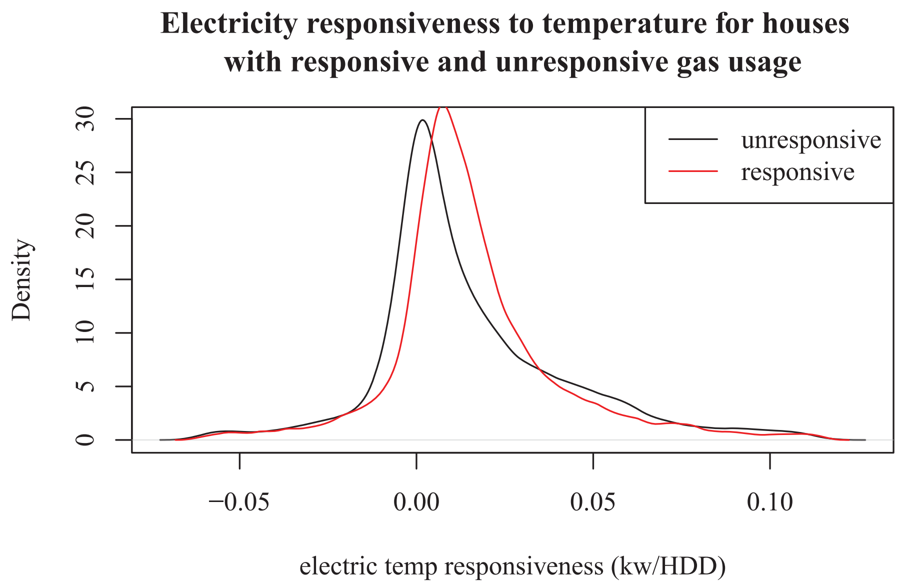

Figure 2.7: Electricity responsiveness to outside temperature for houses that are and are not responsive with their gas use.

We show examples of those results in Figure 2.10 and Figure 2.11. Again we see changepoints just below 60F, with a clearly steeper slope at temperatures below that. The triangle on left represents gas used for space heating while the area below the flatter line represents gas used for other end uses, primarily water heating. These results would suggest that if houses in climate bands T and X were in the same climate then houses in climate band T would use slightly less gas for space heating and more gas for other uses, like water heating.

From the piecewise regression results on natural gas data, we can determine the breakdown of gas used for space heating and other uses. We show that breakdown in Table 2.3. While gas use for space heating can be disaggregated by identifying the portion of gas use that responds more strongly to outside temperature, we cannot disaggregate the other end uses. The Residential Appliance Saturation Study (RASS) finds that for PG&E the average customer with a gas account will use 37 therms for other uses. We simply subtract 37 therms from the total other gas consumption to estimate the gas used specifically for water heating. RASS also suggests that PG&E customers with gas accounts use, on average, 202 therms for space heating annually and 165 therms for water heating annually [17].

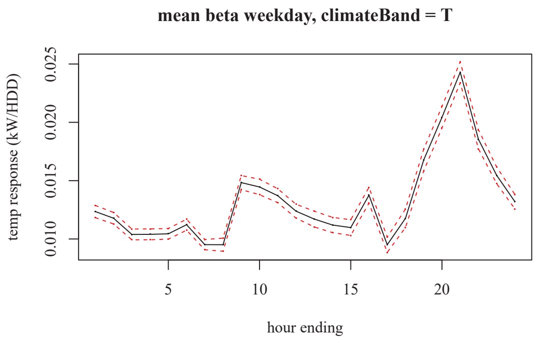

Figure 2.8: β estimates for climate band T, weekdays

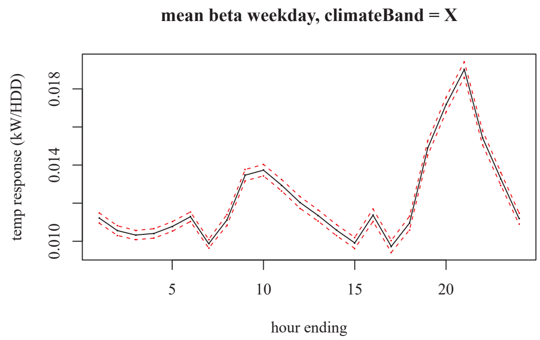

Figure 2.9: β estimates for climate band X, weekdays

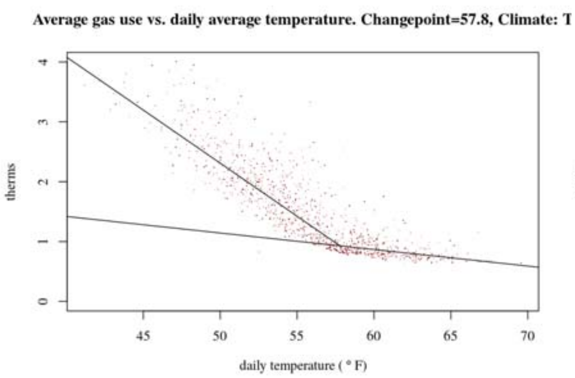

Figure 2.10: Piecewise regression of gas use on temperature, climate band T

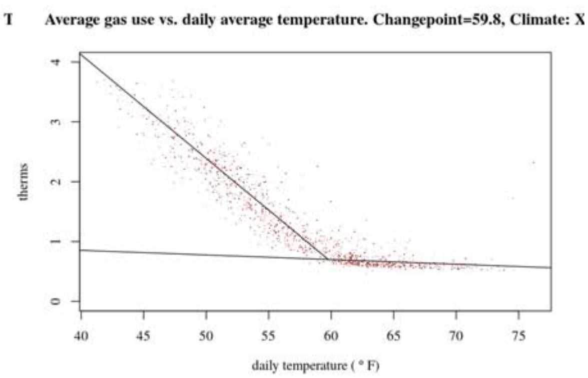

Figure 2.11: Piecewise regression of gas use on temperature, climate band X

We use the information embedded in the hourly resolution electricity data to estimate when heating is occurring. Past efforts have used smart meter data to identify when cooling is occurring [78], but here we make use of the much smaller signal that comes from the furnace fan within the electricity data. To give a sense of how electricity use relates to outdoor temperature, we show, for each hour of the day how electricity use relates to outdoor temperature. We show this for three climate bands: T, X, and S in Figure 2.12, 2.13, and 2.14. Shading indicates density of points. The positive slope shows electricity used for cooling, and the negative slope shows electricity used for heating.

In all cases, we see higher electricity use as temperature drops below 60F. In some

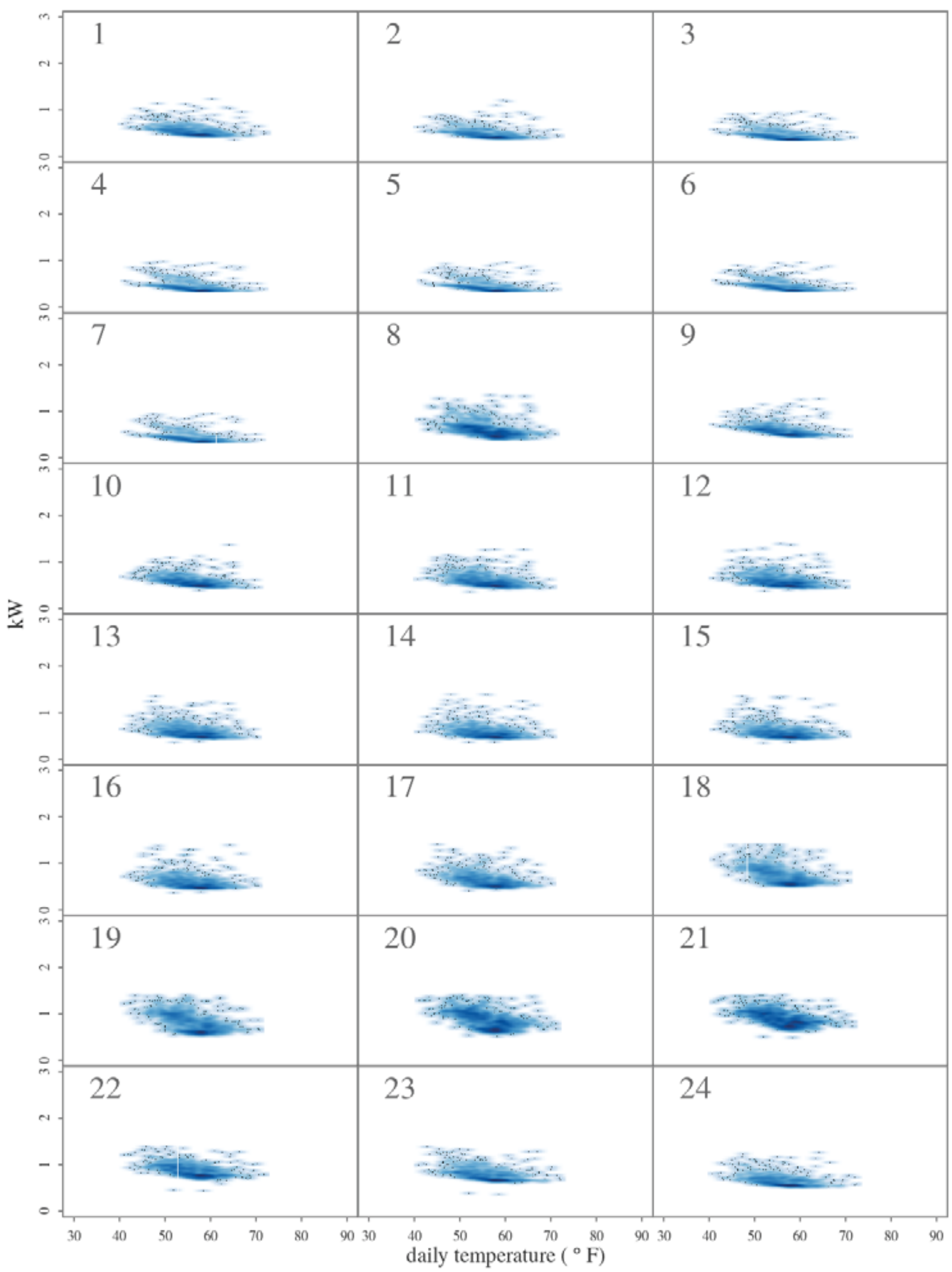

Figure 2.12: Electricity use vs temperature split between hour of day, climate band T.

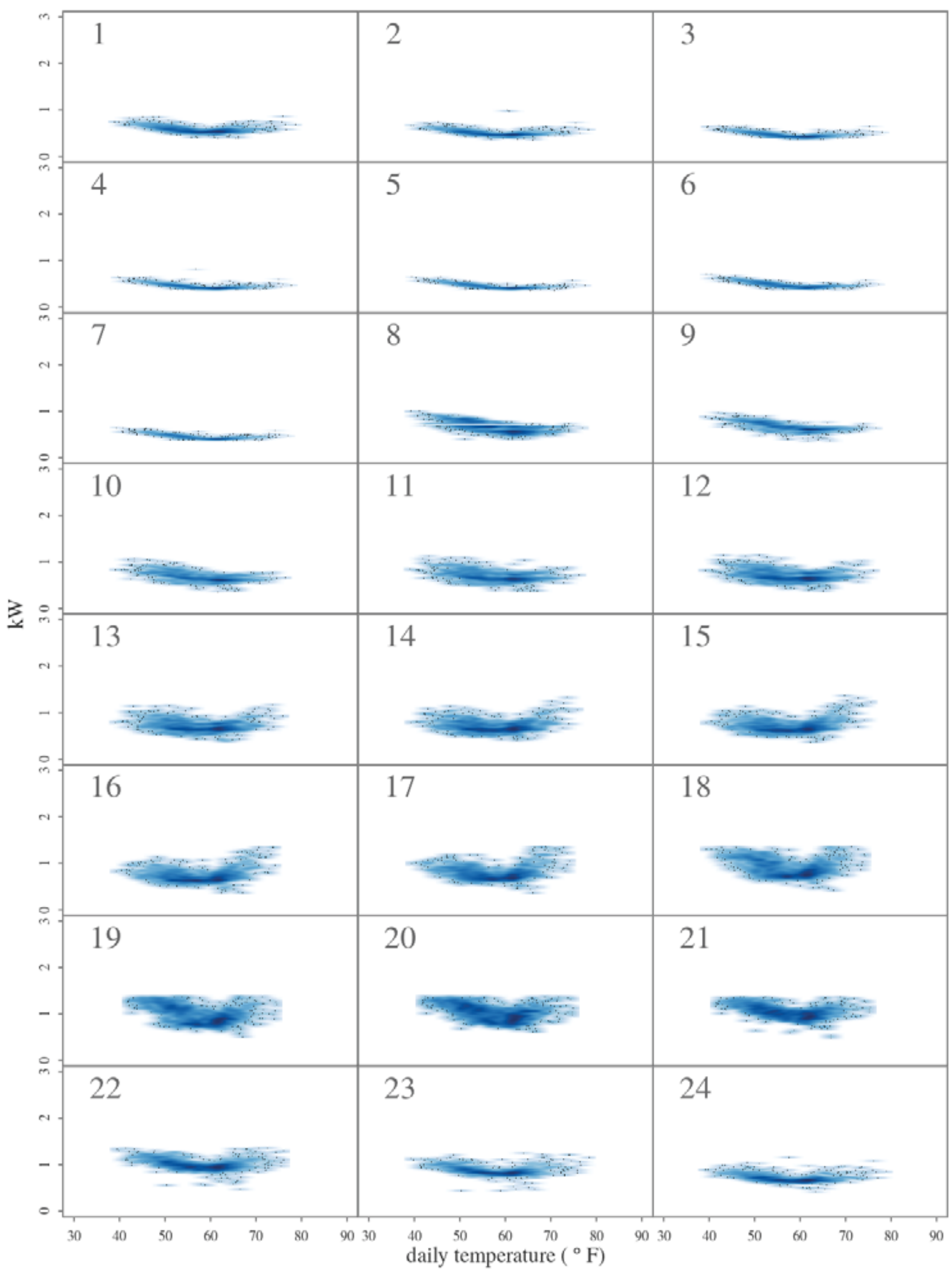

Figure 2.13: Electricity use vs temperature split between hour of day, climate band X.

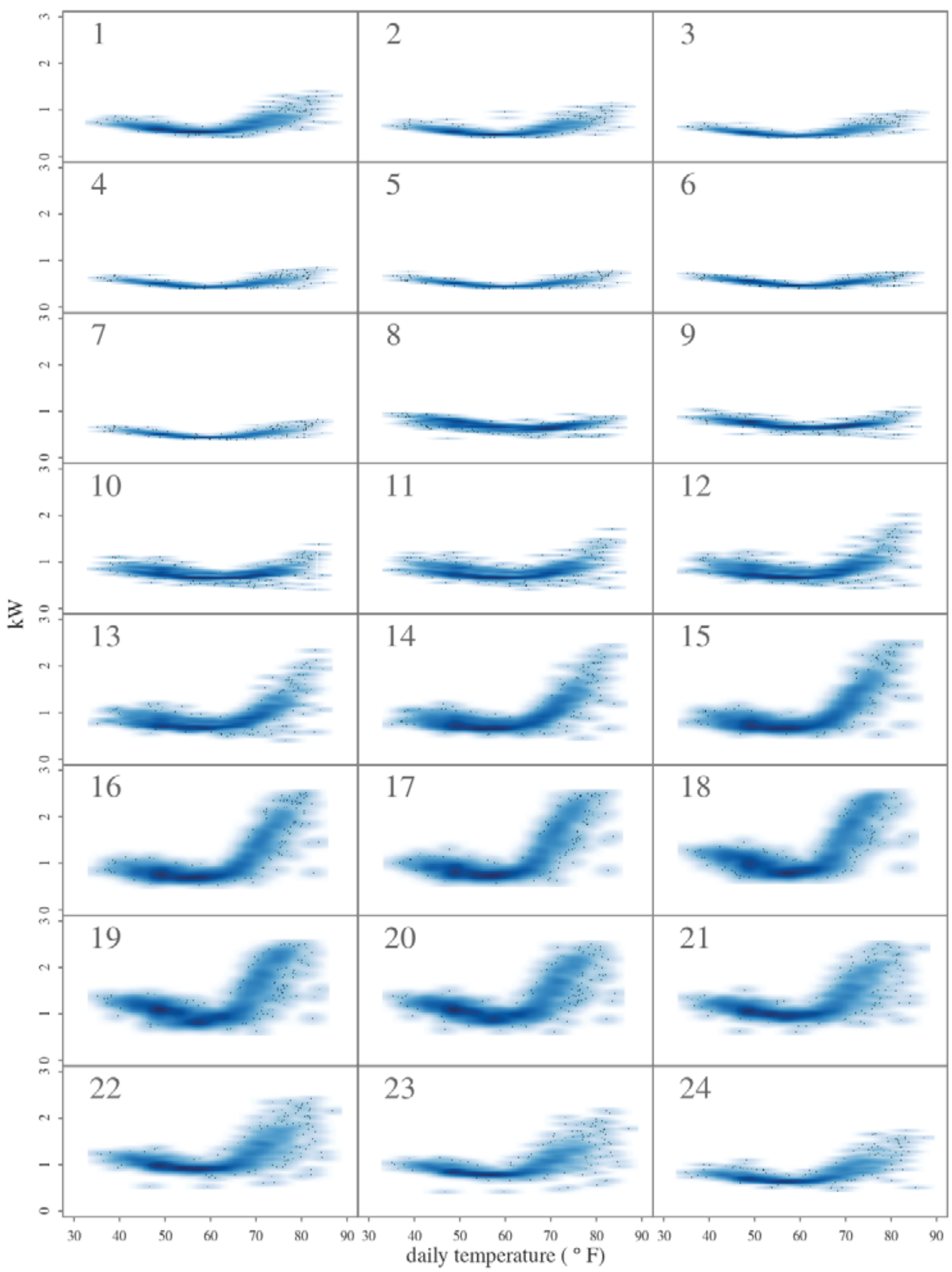

Figure 2.14: Electricity use vs temperature split between hour of day, climate band S.

Climate Band	Space heating (therms)	Water heating and other (therms)
P	293	236
R	198	225
S	221	222
T	172	328
V	232	317
W	189	235
X	266	237
Y	420	341

Table 2.3: Breakdown of gas use

climate bands, like T, there is little, if any, air conditioning. But we can clearly see air conditioning at high temperatures in climate S (which also experiences hotter outside air temperatures). The main feature that we aim to identify in these plots is the slope to the left of the changepoint. We expect this slope to be steeper in hours when heating systems are more likely to be operating or when they operate for a larger fraction of the hour.

We show the estimates of $\beta_{HOD,day}$ in Figures 2.15 and 2.16. We see the highest heating during the hour ending at 9 pm and more midday heating on weekends than weekdays. This is consistent with what we would expect, since we would expect higher occupancy during the day on weekends and higher thermostat setpoints. We also see particularly low temperature response during the hour ending at 7 am. We do not have a good explanation for this phenomenon, as the fixed effects, $\alpha_{HOD,day}$, are also very low for this hour. Electricity use during this hour is both low and unresponsive to temperature. The estimates of $\alpha_{HOD,day}$ can be found in Appendix A.

We also performed this analysis using hourly temperature, rather than the 24-hour moving average. The estimates of $\beta_{HOD,day}$ from that regression can be found in Figures 2.17 and 2.18.

System impacts

Adding new electric loads for space and water heating can impact planning of local distribution, transmission, and generation infrastructure. While we do not do a full system model of optimal transmission and generation investments, we do investigate how electrifying these loads could impact peak demand both at an individual climate band level and for all of PG&E.

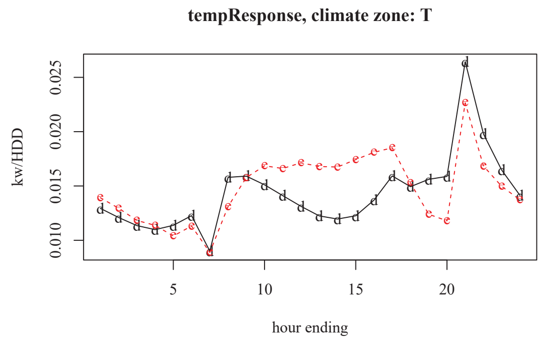

Figure 2.15: Estimates of β_{HOD} for weekdays (d) and weekends (e), climate band T

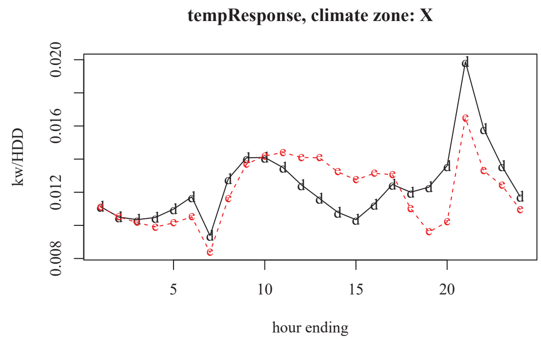

Figure 2.16: Estimates of β_{HOD} for weekdays (d) and weekends (e), climate band X

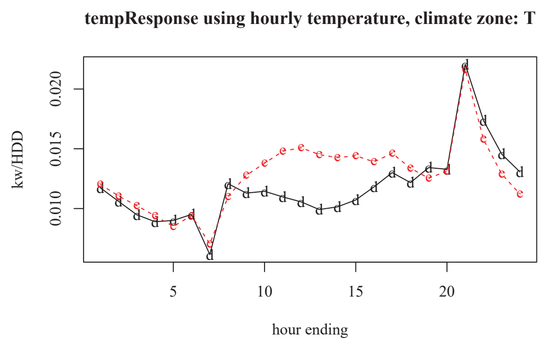

Figure 2.17: Estimates of β_{HOD} using hourly temperature for weekdays (d) and weekends (e), climate band T

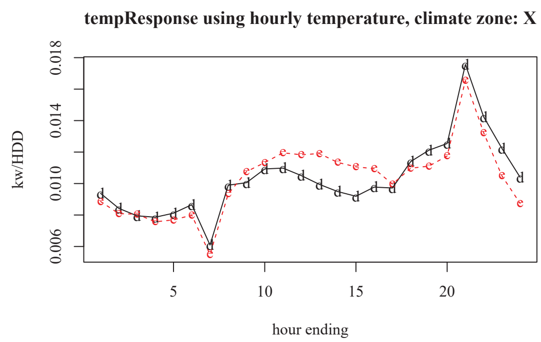

Figure 2.18: Estimates of β_{HOD} using hourly temperature for weekdays (d) and weekends (e), climate band X

Local/Distribution impacts

If we consider a distribution feeder that is serving only residential customers in a single climate band, we can compare how the peak demand will change as space and water heaters are electrified. We divide up the total new electric space heating load into 100 slices and the total new water heating load into 100 slices. Each slice is an hourly load profile for a year to serve 1% of the space heating or water heating needs. We then calculate the increase in peak demand that results when adding a new slice of electric load. Each slice of electrification also has an impact on natural gas consumption. By taking the slices with the lowest impact on peak demand per therm saved, we can form a pseudo supply curve of saved natural gas, where the

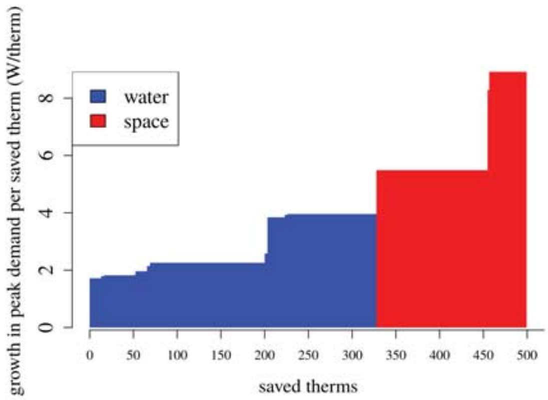

Figure 2.19: Supply curve of gas savings, climate band T

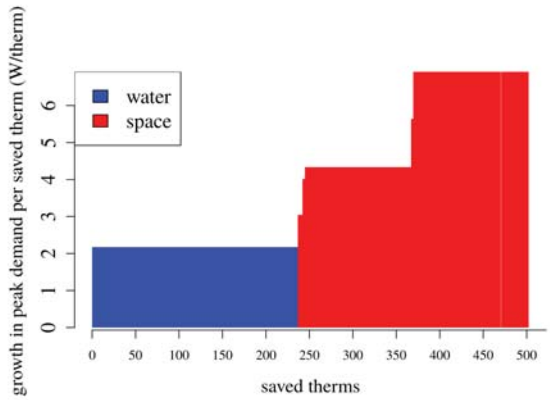

Figure 2.20: Supply curve of gas savings, climate band X

"price" is a watt increase in peak demand per therm saved. We show the results for two climate bands in Figures 2.19 and 2.20. For both we see that electrifying water heating would have less of an impact on residential peak demand for these climates. This is because these climates have very little cooling load and additional heating load on cold days will add to the peak. In hotter climate zones we see the opposite ordering in the supply curve.

Total system impacts

While we have shown what the local impacts might be for only residential loads, it may be more important to see how electrifying loads of different types, in different locations would impact the total system peak, for all of PG&E. Here we take the total system load from CAISO OASIS and add to that the same "slices" of space or water heating demand. But this time, rather than adding slices from only one climate band, we are free to add slices from any climate band, until all climate bands are fully electrified. As before, upon adding each slice there is a change in peak demand and a certain number of therms saved. We find the gas savings that have the smallest impact on peak demand (smallest increase in peak demand per therm saved), and if two sources have the same value of peak demand increase per therm saved then the source with a larger potential gas savings per household is selected first. This is reasonable since in reality, we would target those savings that give the largest gas savings from an intervention. We show the results from this supply curve in Figure 2.21. The black line on this plot shows how the load factor would change as more therms are saved through electrification. We find that about half the gas can be saved with little to no impact on peak demand. After those loads are electrified, about a billion more therms could be saved annually with a peak demand increase of less than 2 GW and increasing load factor by about 5%.

As mentioned earlier, controlling water heaters and moving electricity consumption to lower priced periods may have positive impacts for the grid. We took a coarse approach and formed summer and winter water heating load profiles based on hourly estimates of TDV. These load profiles are found in Figure 2.5. Using those load profiles, we checked to see how the load factor would change as more water heaters were "controlled." We find, as shown in Figure 2.23, that using this coarse profile, only 30% of water heaters should be controlled. In reality, control of all water heaters would provide benefit (though diminishing). The reason for this effect is that new electric water heaters are all adding coincident demand following the new load profile. As new controlled electric loads are added, the control strategy (and electricity price) would have to respond.

We built a second supply curve showing these results in Figure 2.22. One can see that water heating causes a smaller increase in peak demand per therm saved, leading to a slightly higher overall load factor. Load factors with full electrification in all scenarios can be seen in Table 2.4.

Scenario	Load Factor
existing	0.61
with electric water heating	0.65
with electric space heating	0.65
with both space and water heating	0.66
with controlled water heating	0.65
with electric space heating and controlled water heating	0.67

Table 2.4: System load factor with various electrification scenarios

We also present the load duration curves for all of the electrification scenarios in Figure 2.24. In general all load duration curves become flatter as loads are electrified. The flattest are those with both space and water heating electrified. This is also illustrated in Figure 2.25 which shows the change in the load duration curve relative to the baseline (pre-electrification) case. More load is added to off-peak hours than peak hours. Looking at this change, zoomed in on only the top 100 hours (as seen in Figure 2.26) we see that adding very coarse control to only 30% of water heaters could reduce peak demand by about 500 MW. While 500 MW of capacity may not seem very large, smarter control could likely reduce peak by several times that. In addition, complete electrification would only increase peak demand on the order of 2 GW. Relative to this, smarter control of water heaters could have a big impact.

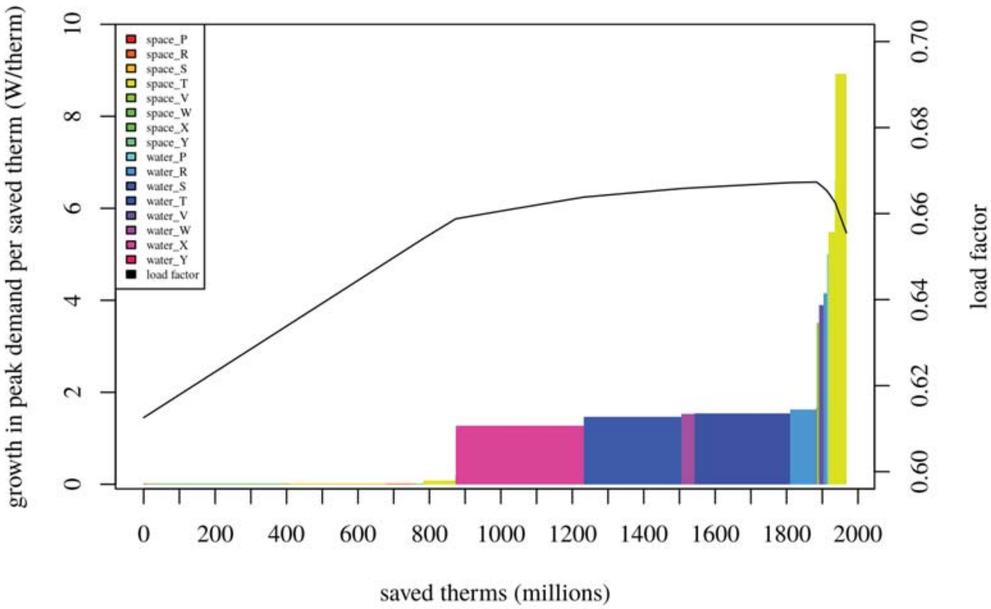

Figure 2.21: Supply curve of electrification

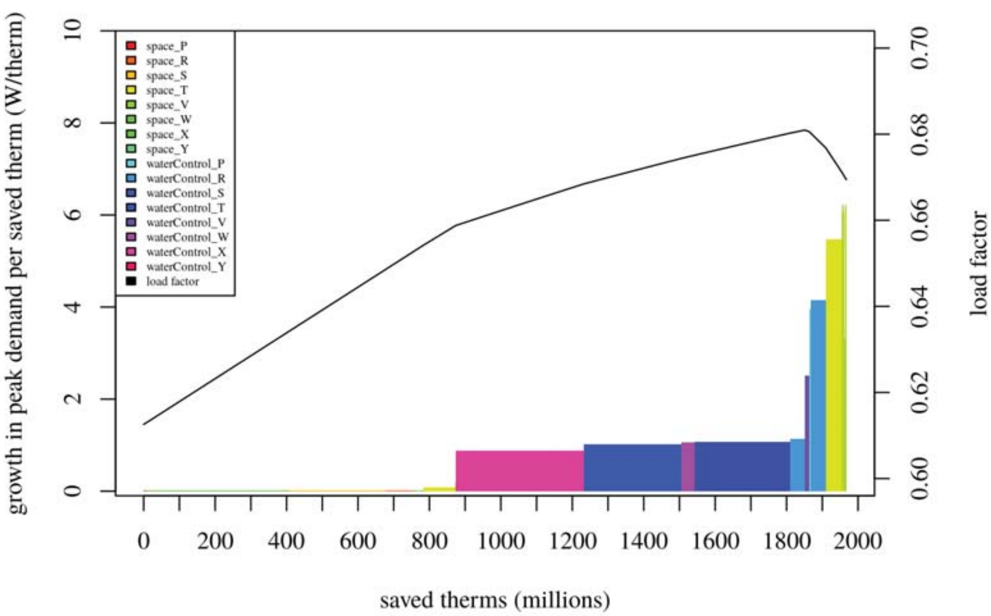

Figure 2.22: Supply curve of electrification, with "controlled" water heaters

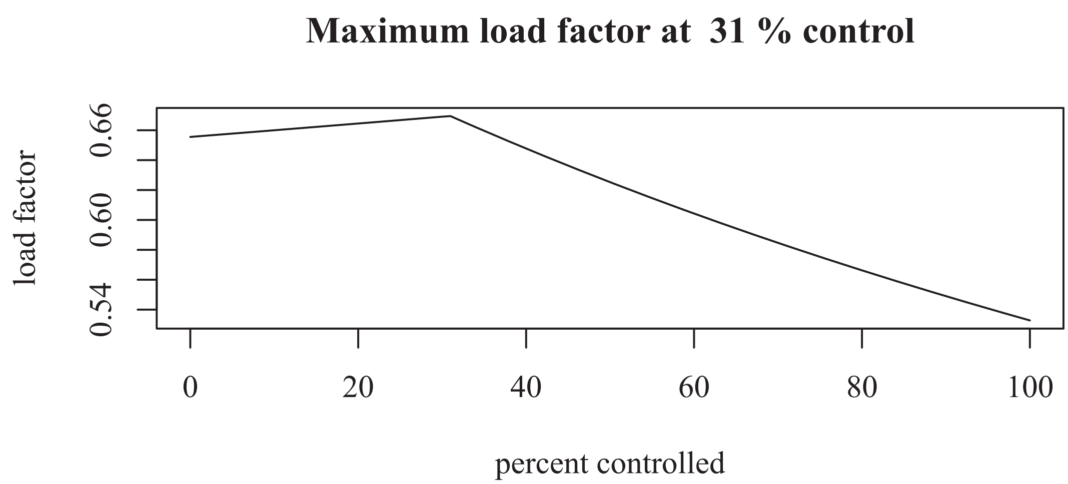

Figure 2.23: Load factor vs. fraction of controlled water heaters

Our analysis so far has not included how electrification of space and water heating loads might help or hurt with integrating a large fraction of variable renewables onto the grid. A great concern is how California will deal with the "duck curve" which refers to a large mid-day reduction in net demand as solar PV production is at its peak. The simple linear program that we described does give an idea of how loads could shift. Grid interactive water heating is an emerging area of research with some pilot-scale commercialization already [79]. While we have shown that load factors would increase with uncontrolled electrified space and water heating, it is unclear what the impact on load factors of dispatchable generators would be with a high fraction of variable renewables.

Comparison of results to another method

With this method we have shown estimates of new electric heating load shapes, based on a using variable responsiveness to outdoor temperature for each hour of the day. Other such methods, based on building energy models come to different conclusions about the load shape. For example, the Database for Energy Efficient Resources (DEER) provides different shapes of savings that might come from making different appliances more efficient [80]. Their heat pump shape is seen in Figure 2.27. If we assume that savings are proportional to consumption, this would also be their estimate of heat pump load.

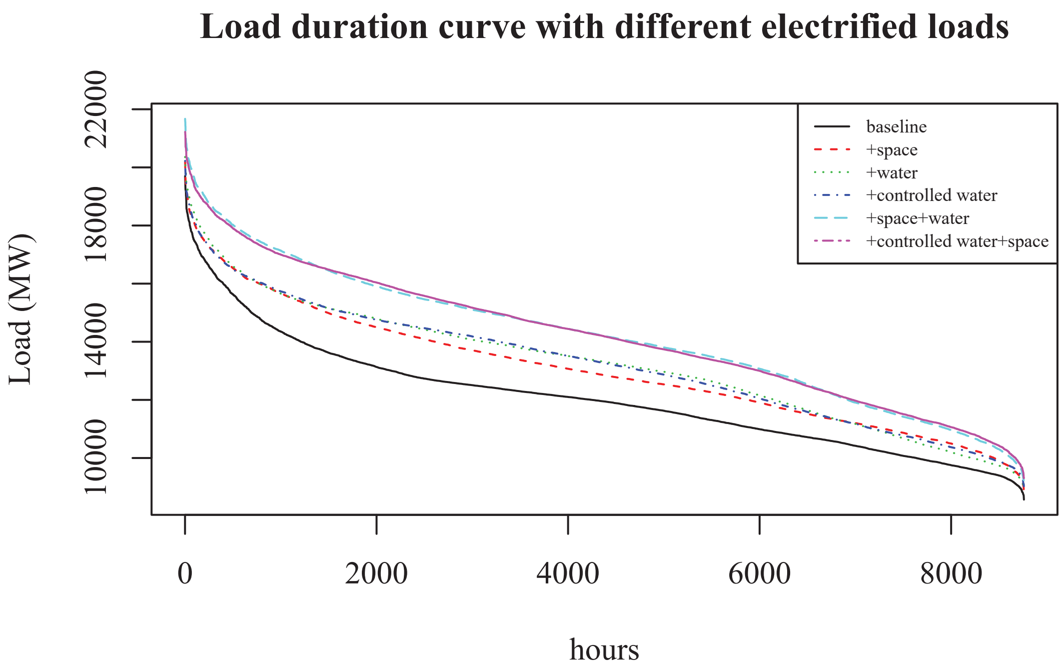

Figure 2.24: Load Duration Curve under various electrification scenarios

For comparison, we show the average heating loads for climate bands T and X in Figures 2.28 and 2.29. The heat pump in DEER is used for both space heating and cooling, which explains the summertime savings. However, there is a large difference between our estimate and the DEER estimate, which presumably is only modeled on outside air temperature. Our results show a much flatter heating load, with peaks in the morning and evening. If our estimate is correct, this would suggest that space heating controls perform a nighttime setback. There is far less overnight heating than DEER would suggest.

2.5 Future Work

While this study used new data sources to empirically estimate new electric heating loads, there are some potential improvements. We make hourly estimates for temperature response that are independent of season. In reality, the hours when heating is most prevalent might vary from month to month due to changes in length of day.

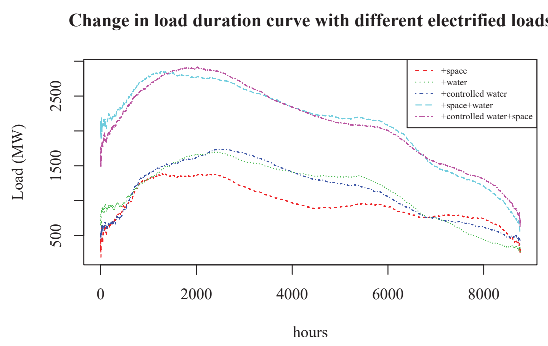

Figure 2.25: Change in Load Duration Curve under various electrification scenarios

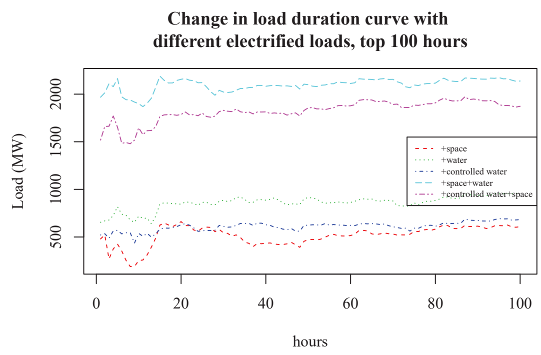

Figure 2.26: Change in Load Duration Curve under various electrification scenarios, top 100 hours

While we had a large dataset, the results in some of the less populated climate bands are questionable. An even larger dataset would allow for month-specific estimates. Another improvement would be a more detailed treatment of daylight savings time. Our analysis is done entirely on standard time, though we would expect some changes in the fixed effects to occur when daylight savings time is in effect.

Future work could also improve our treatment of heat pump performance. In reality, heat pump space heating systems may not have the same power as current natural gas systems. As a result, they may have longer runtimes and even flatter load shapes. Heat pump efficiency, for space heating in particular, decreases as the outdoor temperature drops. This drop in efficiency is not included in our current model. Related to this, we assume a linear relationship between outdoor temperature and space heating energy use. While physics would suggest that a linear approximation is reasonable for a single house (the heat transfer is directly proportional to the difference between inside and outside temperature), when we look at the average house this relationship may no longer hold since the average is a mix of occupants with different behavior and comfort preferences. If different households turn on the heat at different outside temperatures (i.e. they have different changepoints) there would be a nonlinear relationship, particularly around the changepoint.

Heat pumps for space heating could provide a clear climate benefit, but installing them in some climates might increase electricity use in the summer. In climates where air conditioning systems are typically not installed, the summer cooling load may increase. Installing a heat pump for space heating will give customers the ability to cool, when they might not have had an air conditioner before. Additional work could look at survey data to see where customers typically do not have air conditioning but

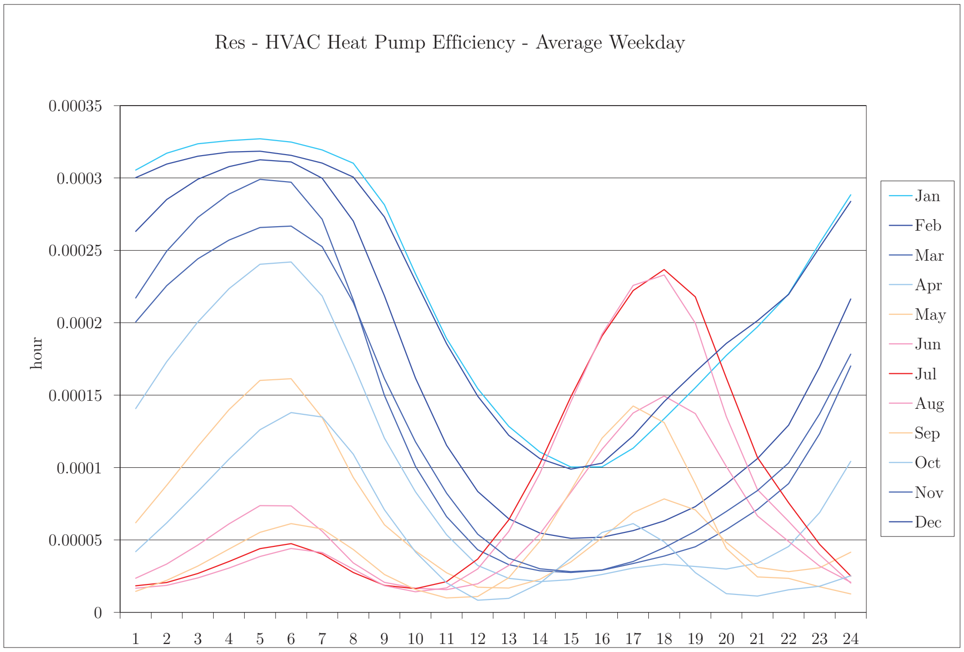

Figure 2.27: DEER database heat pump space heating shape

experience some hot days. Survey data could also identify regions where customers already have central air conditioning systems. These customers would be excellent candidates for switching to heat pumps, as it is a low-cost transition.

Finally, climate change may reduce the need for space heating in some areas of California. The models developed here could be used on climate change scenarios to see what new heating loads might look like when climate change in taken into account. While fewer therms might be saved in a warmer climate, a greater prevalence of air conditioning might make a transition to heat pumps easier, since they are very similar technology.

2.6 Conclusion

Electrification of residential space and water heating in California has the potential to reduce greenhouse gas emissions, integrate variable renewables, and reduce electricity costs. Electrification could save approximately 1/2 of the gas used for residential space and water heating with no increase in peak demand. This transition would allow us to better utilize existing generation capacity, and therefore, potentially, reduce electricity rates. Using a large smart meter dataset, we find that space heating and

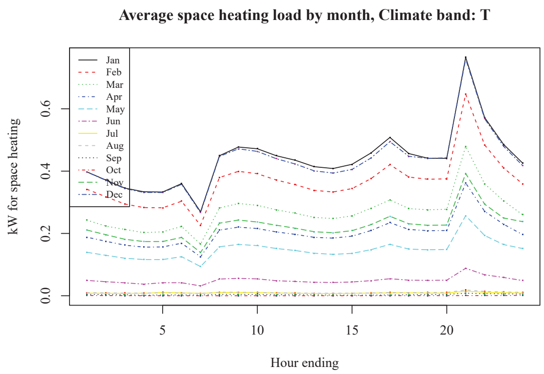

Figure 2.28: Average space heating load by hour and month, Climate band T

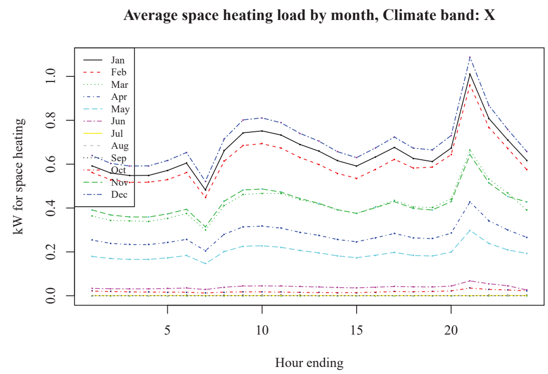

Figure 2.29: Average space heating load by hour and month, Climate band X

water heating will increase both morning and evening peaks for residential buildings. As a result, morning and evening ramps may be exacerbated if new space and water heating loads are not intelligently controlled. This will be of particular concern with high penetration of solar PV installations, as space heating needs will increase as solar production will decrease. PV and space heating in particularly are mismatched seasonally with low solar production during the times of year with higher heating loads. Because buildings contain energy storage in their thermal mass, we could likely shift some demand to earlier in the day through the intelligent control of electric space and water heating, but additional work is needed to understand the seasonal impacts of high fractions of renewables combined with electric heating. Electrification is only one option for decarbonizing the space and water heating sector in California. It is perhaps the most promising alternative. However, creating this massive change in the building stock will require technology that consumers find satisfying, policy that speeds their adoption, and system planning that is ready for these new loads.

Chapter 3

Modeling the stock of residential water heating equipment in California out to 2050

Preface

In this chapter, I present a model that can assist in planning the optimal deployment of water heating appliances in order to meet different emissions targets. Combining data on the existing stock with estimates of lifetime, efficiency, costs, and emissions from electricity we come up with the cost-minimizing deployment of water heaters in order to hit different emissions targets. I performed this work with the guidance of my advisor, Duncan Callaway. I wish to thank Michaelangelo Tabone for insightful conversations.

Chapter Abstract

This chapter shows how California could deploy hot water heaters to meet different emissions targets at lowest cost. We describe several scenarios and show what the lowest cost pathway would be as emissions are constrained. Different water heating technologies are considered, such as gas tank, gas tankless, electric resistance, and electric heat pump, and high efficiency electric heat pump with CO_2 refrigerant. Emissions from natural gas leakage and refrigerant leakage are both considered. We have developed a linear program that minimizes total present operating and capital cost of statewide residential water heating. Relative to the lowest cost case, adding cumulative emissions targets can lower emissions from 71% to 77% without early retirement of water heating appliances. In order to meet a 90% reduction goal from the sector in 2050 (while minimizing cumulative emissions), heat pump water heaters need to have full market share in new construction immediately unless efficiency standards are increased, and most scenarios suggest that the lowest cost pathway include a transition to electric water heating that should have already occurred. Heat pumps need to begin replacing existing gas water heaters by the early 2030s at the latest, while most scenarios suggest that this transition should have already happened to minimize cost. Given projections for gas and electricity prices and costs of water heating equipment, an emissions target of a 90% reduction in 2050 relative to 2010 emissions could be met at a cost of \$97-153/ton CO_2 relative to the unconstrained, lowest cost case. Delaying action beyond 2017 makes the cumulative emissions target unreachable in two scenarios, while a third scenario allows delay until 2029, at a carbon cost of over \$200/ton CO_2.

3.1 Introduction and motivation

California has aggressive emissions reduction goals over the coming decades, including reducing emissions to 80% below 1990 levels by 2050 [1], and past potential studies have indicated that meeting this goal is possible. These studies consistently include substantially reducing or eliminating direct emissions from residential space and water heating as a necessary measure [2, 3, 4, 5, 6, 7]. Since some sectors are more difficult to decarbonize than others, reaching an 80% reduction in 2050 will require even greater reductions in some sectors. Buildings are one sector where even larger reductions will be needed. The Deep Decarbonization study found that in order for the US to reduce emissions 80% below 1990 levels by 2050 much larger reductions must come from the residential sector, with reductions ranging from 89-98%, depending on the scenario [4].

In order to meet this emissions goal, improved energy efficiency, low carbon electricity, and transitioning away from direct combustion of natural gas for heating will all be necessary. However, to date there is neither a plan nor policy in place that will drive this complex transition from natural gas to electricity in millions of homes. Natural gas is the dominant space and water heating technology, and it made up 82% of space heating systems and 75% of water heating systems in 2009 [17]. Of the 354 therms of natural gas consumed per household with natural gas service, 49% was used for water heating and 37% was used for space heating [17]. Direct combustion in homes in California represents 6% of emissions, or about 24 million tons of CO_2 [16].

We will need to take a multi-pronged approach including more efficient building envelopes, more efficient space conditioning systems and water heaters, and reduced hot water consumption if we are to hit aggressive reduction goals of greater than 80% in the buildings sector. But these steps will not be enough; we also will need to largely cease direct combustion of fossil fuels in houses.

In order to plan for this transition, we need to understand how long the transition would take, the magnitude of emissions reductions, and how much it will cost. Planning for targets far in the future with a building stock that is slow to change will require a deeper understanding of how the building stock evolves. A better understanding of what the lowest cost pathway may be will enable policymakers to put in place codes, programs, and incentives in order to transform the market.

In this chapter, we model the turnover of water heating appliances in the building stock, using data from California Residential Appliance Saturation Study (RASS) to set the initial conditions [17]. RASS surveys building characteristics for approximately 30,000 households in California including attributes like the age and type of heating systems. After surveying the literature on heating system lifetimes, we have developed a model that can minimize total present cost of providing heating to residents while meeting an emissions constraint. We track when natural replacements will occur, and, depending on what the emissions target is, decide when to install which kind of heating appliance.

We focus on water heaters in this chapter, though a similar model could be developed for space heating. More natural gas is used by water heaters than space heaters in California, and with a warming climate and more efficient building envelopes the amount of gas used for space heating may further decrease. While space heating in particular can be electrified without contributing to peak demand in many regions in California, the transition to electric water heating in existing buildings may be a less invasive intervention than transitioning space heating systems.

With this stock turnover model we look at several scenarios for space and water heating. Given different projections of gas and electricity prices, technology efficiencies and costs, and hot water use we determine what the lowest cost evolution of the building stock would be. We then compare how, given a constraint on carbon emissions, the stock evolution would change. By adding a tighter carbon constraint, the total present cost increases. From the change in total cost and the change in total emissions, we can determine what average carbon cost would be required to achieve the desired scenario.

From the stock model, we can observe when transitions to different water heating technologies would need to occur in new or existing buildings. The different scenarios show different possible futures, and the timing and cost of the transition differs between them. The model, in unconstrained form, allows for instantaneous transitions in the market. In reality, different technologies market share growth would be limited.

While average lifetimes of heating equipment suggest that most households will replace their space and water heating equipment two to three times before 2050, we cannot wait until the last replacement to start encouraging electrification. The tail of the distribution of lifetimes indicates that many units will last much longer than average. Furthermore, to minimize climate impact policymakers should care about cumulative emissions over time, not annual emissions in a specific target year. Waiting to transition may allow us to reach a future target, but doing so will increase total emissions. We show how the optimal stock transition differs when the goal is annual emissions in a specific year versus cumulative emissions. Taking different assumptions into account, this work provides insight into how the transition to electrified heating could occur and when policies should be put in place to decarbonize heating by 2050 at the lowest cost. While analysis on lifetimes exists as part of efficiency standards, the contribution of this paper is integrating lifetimes, varying capital and fuel costs, and emissions factors to give a more holistic view to policymakers on what should be done, when, and at what cost to electrify water heating.

3.2 Methods

We developed a linear program that will find the lowest present cost deployment trajectory of different water heating technologies in order to meet an emissions target. We define five different broad categories of technologies and three scenarios. Water heaters generally fall into the categories of natural gas tank, natural gas on demand, electric resistance, electric heat pump, and high efficiency electric heat pump. We define three future scenarios that aim to show the range of expected carbon prices necessary to achieve a given emission reduction. The scenarios include a base case, which gives the typical outcome that we might expect in terms of technology cost and efficiency and grid emissions. The inputs to this scenario are typical reference cases used in other models. We also then consider a "renewable and efficient" case with more efficient technology available (though at slightly higher cost), more efficient use of hot water, and gas prices rising faster than electricity prices. This case also assumes that electricity has lower emissions far in the future than the basecase. Finally we consider a "slower transition" case which has higher grid emissions, less efficient appliances, and greater use of hot water. The complete set of assumptions that we vary include: fuel emissions factors, refrigerant leakage from heat pumps, technology costs and efficiencies, and hot water consumption. In general, we expect the "slower transition" case to have greater unconstrained emissions, and therefore, with respect to hot water heater deployment, it would take greater effort in order to meet an emissions goal.

Assumptions

In this section we will go through all the assumptions that we make for the inputs to the linear program. All dollar values are in 2016 dollars. Any values provided in different year dollars are adjusted using the consumer price index.

Fuel price

All scenarios use actual California average natural gas prices for 2010-2016 and then escalate these prices at different rates depending on the scenario. The 2016 average residential natural gas price in California was 1.19/therm and the average electricity price was \$0.174/kWh [81, 82].

The 2017 Annual Energy Outlook (AEO) includes annual growth of residential gas prices of 1.1% and annual growth of residential electricity prices of 0.4% for their reference case. We use these growth rates for the base case scenario of the model. For the other scenarios, we use the AEO cases with the biggest difference in growth rates: the high and low "oil and gas technology" cases. The low technology case uses a gas annual growth rate of 2% and an electricity growth rate of 0.7%. The high technology case uses a gas annual growth rate of 0.6% and an electricity growth rate of 0.2% [83]. The high technology case will be used for our "slower transition" scenario, representing a future more focused on developing low-cost fossil supply-side resources. The low technology case will be used for our "renewable and efficient" scenario, representing a future more focused on a more efficient demand side, with higher cost fossil resources.

Fuel emissions factors

We assume that natural gas has emissions of 6.11 kg CO_2/therm delivered to residential customers over the entire period [38]. For electricity, we assume a portion of electricity is generated by renewables that are effectively carbon free for our calculation. We set targets of 20% in 2014, 25% in 2016, 33% in 2020, 40% in 2024, 45% in 2027, and 50% in 2030. These targets are set by a number of current policies, such as Senate Bill X1-2 and Senate Bill 350. All scenarios use the same renewables share through 2030 but vary in their 2050 targets. The “renewable and efficient” scenario includes 95% renewables in 2050, while the “slower transition” scenario assumes a 75% RPS in 2050. The base case assumes an 85% RPS in 2050. The share of renewables is linearly interpolated for years in between the explicitly specified points. For non-RPS electricity, we assume a natural gas generator is used, that is 45% efficient which is the average combined cycle plant efficiency [33, 49]. We assume natural gas emissions to the power plant are slightly lower than equivalent emissions to residential customers, due to reduced leakage. We use the EPA value of 5.302 kg CO_2/therm [84]. Futher improvements in gas plant efficiency are not accounted for in any of the cases. Putting these assumptions together, we assume that emissions from electricity generation, with no renewables, are 0.402 kg/kWh.

Refrigerant Leakage

Currently most heat pump water heaters on the market use refrigerants that have a high global warming potential. There also are new “advanced” heat pumps on the market that are both very efficient and use CO_2 as the refrigerant. Refrigerant leakage in these heat pumps is not an issue. Other refrigerants, such as R-134a, have global warming potential (GWP) of 1430. Policies aim to phase out the usage of very high GWP refrigerants, and we reflect this aim in our model inputs. We assume that a conventional heat pump contains approximately 1/4 kg of refrigerant, all of which will leak out over its average lifetime. We assume that a heat pump water heater contains about half as much refrigerant as a room air conditioning unit which is substantially higher in power than a typical heat pump water heater and contains less than 1/2 kg of refrigerant [85]. We therefore assume that conventional heat pumps emit an additional 25 kg of CO_2-equivalent emissions each year in the base case and “renewable and efficient” case. In the “slower transition” scenario we assume that rather than R-134a, R-410a is used in heat pump water heaters, with a GWP of 2088. This would be equivalent to an additional 38 kg of CO_2 equivalent emitted each year. In 2016, 197 countries adopted an amendment to the Montreal Protocol to cut consumption of HFCs (like R-410a and R-134a) starting in 2019 [86]. We model that change in our optimization by ramping down refrigerant emissions in all scenarios. In the “slower transition” case we consider a transition from R-410a to R32 (GWP of 675, emissions of 13 kg/year) and in the “renewable and efficient” case we consider a transition from R-134a to HFO-1234yf (GWP of 4, negligible emissions) [87]. In the

Table 3.1: Lifetime distribution parameters

Parameter	Electric	Gas
α	13.19	11.64
β	1.174	1.307
θ	0	3.196
Mean lifetime	12.48	13.93

base case we consider a transition from R-134a to R32. We model these transitions linearly between 2019 and 2050, meaning that installations in each year have the refrigerant emissions associated with that year, but they will continue emitting at that rate over their lifetime.

Appliance lifetime

We consider that lifetimes of all technology types follow a Weibull distribution that is in the form in Equation 3.1where $P(x)$ is the probability that the appliance is still in use at age x. The other parameters α, β, and θ define the scale, shape, and delay respectively of the survival of appliances. The parameters used in our model are taken from Lutz et al. who determined them from combining shipments data and survey data of the surviving stock [88]. They are shown in Table 3.1.

$$P(x) = e^{-(\frac{x-\theta}{\alpha})^{\beta}} \tag{3.1}$$

The same gas lifetimes are used for all gas water heaters (gas tank and gas on demand), and the same electric lifetimes are used for all electric water heaters (resistance, heat pump, and advanced heat pumps). Heat pumps are assumed to have similar lifetimes as electric resistance water heaters [89].

Appliance efficiencies and costs

For the efficiencies of existing appliances and efficiencies and costs of future appliance installations, we base our assumptions on the same assumptions used in the National Energy Modeling System (NEMS) [90]. The technology forecasts used in NEMS provide both a reference case and an advanced case. For the base case and "slower transition" case we use the NEMS reference case for costs anf efficiencies, and we base our "renewable and efficient" case on the assumptions in the NEMS advanced case. EIA provides estimates of costs and efficiencies for 2013, 2020, 2030, and 2040. We extrapolate trends out to 2050 and interpolate for years between data points. For

Table 3.2: Technology efficiencies

Parameter	Resistance	Heat pump	Advanced HP	Gas Tank	Gas OD
Base and Slower Transition					
2009	0.9	2		0.6	0.82
2013	0.92	2	4.5(in 2016)	0.62	0.82
2020	0.95	2.3		0.62	0.82
2030	0.95	2.45		0.62	0.82
2040	0.95	2.5		0.62	0.82
2050	0.95	2.55	5	0.62	0.82
Renewable					
2009	0.9	2		0.6	0.82
2013	0.92	2	4.5(in 2016)	0.62	0.82
2020	0.95	2.3		0.67	0.87
2030	0.96	2.5		0.74	0.93
2040	0.96	2.75		0.8	0.98
2050	0.96	3	6	0.86	0.98

both the electric-favored and mid cases we use "typical" costs and efficiencies. The efficiency and cost assumptions can be seen in Tables 3.2 and 3.3.

Advanced heat pumps are not defined for the NEMS model, so we base those costs and efficiencies on the currently available Sanden GUS-A45HPA CO_2 heat pump water heater. It has a COP of 4.5, and we assume that it has an installed cost of $4500, decreasing linearly to $4000 in 2050. In the "renewable and efficient" case we assume that advanced heat pumps reach an energy factor (EF) of 6 in 2050, while in the base case and "slower transition" case we assume they reach an EF of 5 in 2050.

Hot water demand

We assume that 3400 kWh of heat are used annually for hot water heating. We arrive at this estimate first using the estimate that the average gas water heater uses 193 therms per year [17]. Converting this to kWh and assuming a 60% efficient water heater arrives at a value of 3410 kWh. In terms of volume of water heated, this would mean that 54.6 gallons of water are heated from 55 degrees to 125 degrees daily. Lutz et al. find an average daily median volume of hot water use to be 50.6 gallons per day [91]. Over time, we believe that the per household hot water use will decrease due to water efficiency measures. The Pacific Institute found that there is potential for a reduction in indoor residential water use of 45-55%. About half of this potential

Table 3.3: Technology costs

Parameter	Resistance	Heat pump	Advanced HP	Gas Tank	Gas OD
Base and Slower Transition					
2009	633	2029		1030	1751
2013	659	2029	4500 (in 2016)	1035	1730
2020	659	1926		1035	1730
2030	659	1926		1035	1730
2040	659	1926		1035	1730
2050	659	1926	4000	1035	1730
Renewable					
2009	633	2029		1030	1751
2013	659	2029	4500 (in 2016)	1035	1730
2020	659	2029		1267	2039
2030	752	2132		1370	2529
2040	752	2235		1473	2967
2050	752	2338	4000	1576	2967

comes from uses that may use hot water, such as dishwashers, faucets, showers, and clothes washers [92]. In the base case we assume a 1/2% per year reduction in hot water use, or a cumulative 19% reduction between 2010 and 2050. In the "renewable and efficient" case we assume a 1% per year reduction (34% cumulative reduction), and in the "slower transition" case we assume 0.1% per year reduction (4% cumulative reduction).

Population growth

The population in California is expected to grow, and we assume that the housing stock will grow at the same rate as that population growth. We use the population forecast for each individual year from the Department of Finance to determine new construction. We use the same population for all scenarios [93]. We do not specifically account for early retirement of any water heating appliances.

3.3 Model structure

We have developed a linear program that minimizes the present cost of providing hot water. We assume that the building stock in 2009 is characterized by the ages and types of water heaters found in RASS. All existing water heaters come at zero cost.

The number of water heaters grows each year, so there are some new installations. There also are installations as equipment is replaced. There are no early retirements of equipment.

A linear program is generally of the form of Equation 3.2. The complexity of the model resides in building the A matrix and f and b vectors appropriately to accurately account for constraints and costs of the optimization. The linear program selects x that minimizes costs $f^T x$. The elements in vector x represents the number of installations of each technology type, of each vintage.

$$\min_x f^T x \text{ subject to } \begin{cases} A \cdot x \leq b, \\ A_{eq} \cdot x = b_{eq} \end{cases} \tag{3.2}$$

In order to include all of the constraints in the optimization we build up the A matrix using several submatrices and the b vector with several subvectors or scalars as seen in Equations 3.3 and 3.4. Each A and b pair creates a necessary constraint for the optimization. A similar process is used to build the equality constraints using A_{eq} and b_{eq}. The objective function f calculates the total present cost of decision x. The total cost is the sum of fuel costs, equipment cost, and various transition costs. We describe the components of f after describing all variables.

$$A = \begin{bmatrix} A_1 \\ A_2 \\ A_3 \\ A_4 \\ A_5 \end{bmatrix} \text{ and } A_{eq} = \begin{bmatrix} A_{eq1} \\ A_{eq2} \end{bmatrix} \tag{3.3}$$

$$b = \begin{bmatrix} b_1 \\ b_2 \\ b_3 \\ b_4 \\ b_5 \end{bmatrix} \text{ and } b_{eq} = \begin{bmatrix} b_{eq1} \\ b_{eq2} \end{bmatrix} \tag{3.4}$$

The inequality and equality constraints are described below.

$A_1 = -1 \times I$	$b_1 = zeros$	nonnegative installs
$A_2 = -1 \times (R_{diff} - T_{elecNew})$	$b_2 = zeros$	no transitions to gas
$A_3 = T_{replaceOD} - D_{retireOD}$	$b_3 = zeros$	replacements $\leq$ retirements
$A_4 = -1 \times R$	$b_4 = totalInstalls$	total installs $\geq$ total stock
$A_5 = Emissions_{total}$	$b_5 = emissionCap$	total emissions $\leq$ cap

$A_{eq1} = Survival_{2009}$	$b_{eq1} = Stock_{2009}$	2009 stock matches observations in RASS
$A_{eq2} = T_{gasNew} + T_{elecNew}$	$b_{eq2} = new$	new construction installs = new construction projection

where

$D_{retireOD}$ is matrix where the (t, i) element represents the fraction of on demand water heaters of type i that retire at time t

$Demand$ is an input vector where the (t) element represents the annual energy delivered in hot water, in kWh, in year t.

η is an input vector where the (i) element represents the efficiency of that unit

$EmissionFactor_{elec}$ is an input vector where the (t) element represent the emissions in year t that result from 1 kWh of electricity production

$EmissionFactor_{gas}$ is an input vector where the (t) element represent the emissions in year t that result from combustion of 1 therm of natural gas

$Emissions_{total}$ is a vector where the (i) element represents the total emissions that an installation would have over the total optimization period

$emissionCap$ is a scalar representing the total allowable emissions

$GasLine$ is an input vector where the (t) element is the discounted cost of installing a gas line in a new construction at time t

$Leak$ is an input vector where the (i) element is nonzero only for traditional heat pump types and represents the average annual CO_2-equivalent emissions from refrigerant leakage

new is a vector where the (t) element is the total number of new constructions in that year

R is matrix where the (t, i) element represents the fraction of water heaters of type i that are still surviving at time t

R_{elec} is the same as R but only nonzero for electric technology types

$R_{diffElec}$ is a matrix where the (t, i) element represents the change in surviving fraction of electric water heaters of type i compared to the surviving fraction at time $t - 1$

$R_{diffNew}$ is the same as $R_{diffElec}$ but is nonzero only for new construction technology types

R_{diffOD} is the same as $R_{diffElec}$ but is nonzero only for on demand technology types

$Survival_{2009}$ is a diagonal matrix where the (i, i) element shows the fraction of water heaters of type i that would be surviving in 2009

$Stock_{2009}$ is vector where the (i) element represents the number of water heaters of type i that were observed in the building stock in 2009

$T_{elecNew}$ is a matrix where the (t, i) element is 1 if the heating type i is electric, can be installed at time t, and is a "new construction" type

T_{gasNew} is a matrix where the (t, i) element is 1 if the heating type i is gas, can be installed at time t, and is a "new construction" type

T_{newOD} is a matrix where the (t, i) element is 1 if the heating type is on demand gas, can be installed at time t, and is a "new construction" type

$T_{replaceOD}$ is a matrix where the (t, i) element is 1 if the heating type i is on demand gas, can be installed at time t, and is a "replacement" type

$Transition$ is an input vector where the (t) element is the discounted cost of transitioning from gas to electric water heating at time t

$TransitionOD$ is an input vector where the (t) element is the discounted cost of transitioning from a gas tank to an on demand gas water heater at time t

$totalInstalls$ is a vector where the (t) element is the total number of water heaters that must be installed at time t

At a high level, the total cost function f can be calculated using the sum of the cost components shown in Equation 3.5. The vector f is the same length as x and each element represents the total present cost of a single installation of each type found in x. It is a sum of vectors, each of the same length as x that account for the discounted equipment cost, the discounted lifetime fuel costs, and the discounted transition cost of switching from gas to electric water heating or from switching from gas tank to on demand gas. The connection cost to the gas distribution system is also included for new construction in some model runs. All costs are discounted back to 2010, since that is the first real decision year. Installations prior to 2010 are constrained to the observations in RASS.

$$\begin{aligned} f = {} & Equipment + FuelCost \\ & + TransitionCost + TransitionCostOD + GasLineInstallCost \end{aligned} \tag{3.5}$$

While some of these components, like equipment and fuel, are straightforward to calculate, others greatly increase the complexity of the linear program. First, transition costs are included to switch from gas water heating to electric water heating, which may require an upgrade of the electrical panel or installation of a new outlet. Second, switching from a gas tank water heater to a gas on demand water heater requires installation of a larger gas line. Third, new constructions are not subject to these transition costs, but we consider the additional cost of connecting new houses to the gas distribution system.

In order to track these transition costs, we need to separate which installation are in new construction and which are in existing buildings. If the number of electric installations in a year grows by more than the new constructions, then we assume there were transitions from existing gas water heaters to new electric water heaters. This nonlinearity means that we need additional types specific to new construction that are exempt from transition charges and then constrain those to the number of new constructions in each year.

While there are five water heater technologies (heat pumps, electric resistance, advanced heat pumps, gas on demand, and gas tank) we need to use more types to include the transition costs. We effectively have eleven heating types: heat pumps, electric resistance, advanced heat pumps, gas on demand, and gas tank, heat pumps in new construction, advanced heat pumps in new construction, gas on demand in new construction, gas tank in new construction, and gas on demand replacement. Therefore, if we ran the optimization over 100 years, there would be 1100 different types that could be chosen from. Each i element in x represents a combination of technology and vintage.

We build a survival matrix R that shows, for an installation x_i, what fraction would survive at time t. The product of R and x is therefore a time series of the total stock. We use this survival matrix R to allow installations to serve load only in years including and after their vintage. This R matrix contains the values from the Weibull distribution described earlier. For years prior to their vintage, the value in the matrix is zero by definition. The $R(t, i)$ element represents the fraction of water heaters of type i (from the x vector) that is still in the building stock at time t.

We build a matrix R_{elec} that is nonzero only for electric water heater types and then calculate the difference between R_{elec} and R_{elec} shifted by one time step, and refer to this new matrix as $R_{diffElec}$. We also build a matrix $T_{elecNew}$, with the same dimensions as R_{elec}. The (t, i) element in $T_{elecNew}$ is 1 if the heating type i is a "new construction" type, it can be installed at time t, and if type i is an electric type. The matrix $R_{diffElec} - T_{elecNew}$ when multiplied by x gives the number of transitions from gas to electric, in each year. This matrix is used to calculate the total transition cost as shown in Equation 3.6.

$$TransitionCost = Transition \cdot (R_{diffElec} - T_{elecNew}) \tag{3.6}$$

Tracking the number of transitions from gas tanks to on demand gas is slightly more complicated. The number of transitions is equal to the change in total stock of on demand water heaters plus on demand retirements minus on demand installs in new construction minus on demand replacements. To calculate the cost, we need to build similar matrices as were used for electric transitions. First, we build a matrix R_{diffOD} which is similar to $R_{diffElec}$ but nonzero only for on demand water heater types. We also build a matrix $D_{retireOD}$ where the (t, i) element is the fraction of on demand water heaters of type i retire at time t. We build two more matrices $T_{replaceOD}$ and T_{newOD}. These are similar to $T_{elecNew}$, but are only nonzero only for the on demand replacement type and on demand new construction type respectively. The transition cost to on demand water heating in matrix form is shown in Equation 3.7

$$TransitionCostOD = TransitionOD \cdot (R_{diffOD} + D_{retireOD} - T_{newOD} - T_{replaceOD}) \tag{3.7}$$

Finally, in some model runs we also wish to include the cost of connecting a new construction to the gas distribution system. The upfront cost of new construction can be lower if gas is not installed in the first place. In some model runs we include a $2000 charge to install a gas water heater in new construction. The actual cost of a gas connection is estimated to be over $6000 in Palo Alto, but we assume only a fraction of this is attributable to the water heater [94]. While these charges may vary widely by location, we consider this \$2000 charge conservative. In order to calculate charges for a gas connection in new construction we also need a matrix T_{gasNew}, similar to $T_{elecNew}$ but only for "new construction" gas types.

$$GasLineInstallCost = GasLine \cdot T_{gasNew} \tag{3.8}$$

These equations are sufficient to run the linear program without an emissions constraint, but in order to constrain the emissions, we also need to calculate what those emissions would be. Equations 3.9 through 3.12 show how the emissions are calculated. *Demand* refers to the total demand for delivered hot water energy per year in kWh. *EmissionFactor* are annual values either in units of kg CO_2/kWh for electricity or CO_2/therm for gas. *Leak* is a vector of annual refrigerant leakage rates for each water heating type and vintage. Finally, η is a vector of efficiencies for each heating type and vintage.

$$Emissions_{elec} = R_{elec} \cdot EmissionFactor_{elec} \circ Demand \tag{3.9}$$

$$Emissions_{gas} = R_{gas} \cdot EmissionFactor_{gas} \circ Demand/thermTokWh \tag{3.10}$$

$$Emissions_{refrig} = R \cdot \mathbf{1} \circ Leak \tag{3.11}$$

$$Emissions_{total} = (Emissions_{elec} + Emissions_{gas}) \cdot 1/\eta + Emissions_{refrig} \tag{3.12}$$

In order to set an emissions constraint, $Emissions_{total}$ is appended to the A matrix above (as shown in A_5), with the emissions cap added to the b vector.

3.4 Results

We run this model to determine the lowest cost evolution of the building stock to serve all houses with given hot water demands in each year. We then calculate the carbon emissions that would result from that evolution and set an additional constraint that limits carbon emissions to 1% lower than the unconstrained case. We continue constraining emissions by an additional 1% until no feasible solution exists. For each model run, we run the optimization out to 2075, and then calculate the costs and emissions only in the window from 2010 to 2050. The change in cost and change in emissions makes it possible to calculate the average (present) carbon cost that would be required to reach the emissions target. We also calculate the difference in costs and emissions as the constraint gets tighter to estimate the marginal cost of the emissions reduction. We also compare these results using cumulative emissions targets with the results that arise when there is only an annual target in 2050. Finally, we estimate how the average carbon price would change as action toward electrification of water heating is delayed.

Evolution of building stock

First we show how the stock would evolve with unconstrained emissions, with the gas installation charge. Those results are seen in Figure 3.1. We see that gas tank water heaters continue to dominate the market and only after 2030 do heat pump water heaters gain market share in new construction. The high upfront cost of gas on demand water heaters keeps them out of the market, even for replacements of existing on demand gas water heaters when no retrofit charge would be assessed.

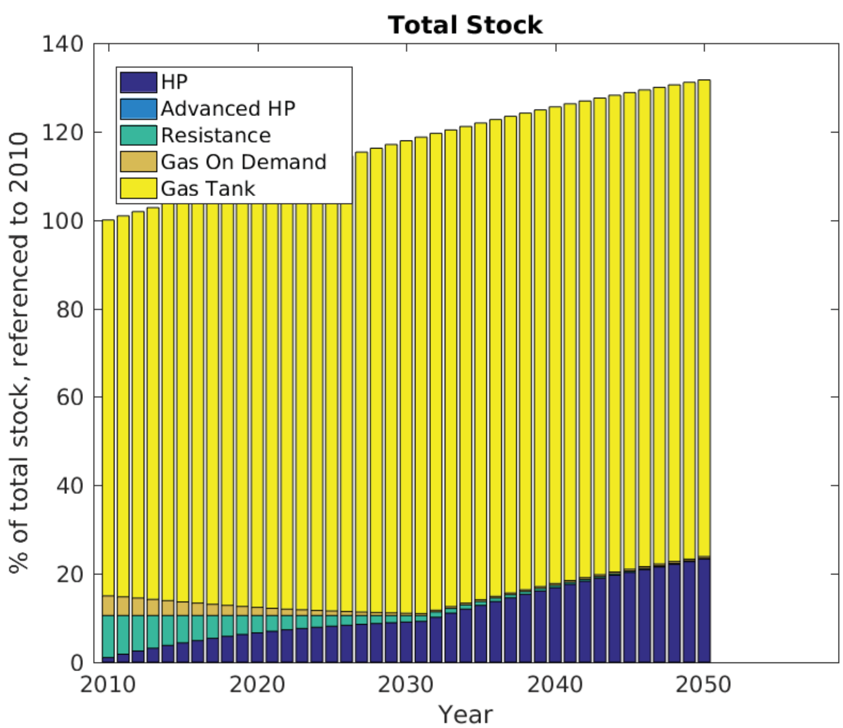

Figure 3.1: Unconstrained evolution of building stock in base case, with gas install cost.

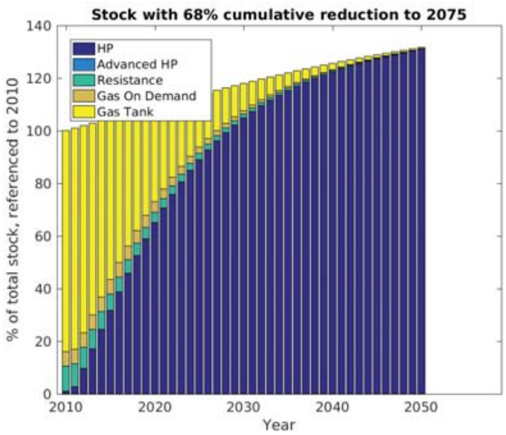

Figure 3.2: Evolution of building stock in base case

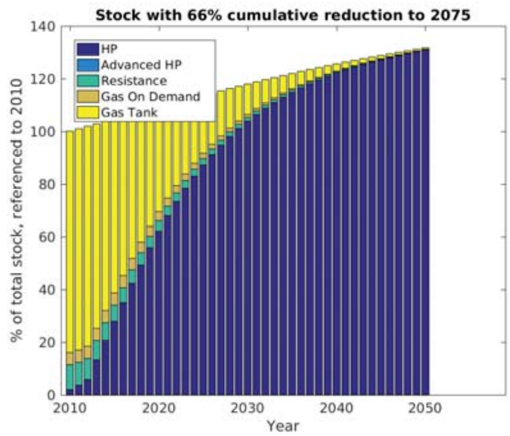

Figure 3.3: Evolution of building stock in base case, with gas install charge

The emissions constraint considers cumulative emissions not emissions in a single year. From a policy point of view, we *should* care about total emissions, since that is what effects climate. Upon meeting a cumulative emissions constraint, we also check which model run hits a 90% annual emissions reduction in 2050, relative to 2010, since that is more in line with existing policy goals. The output from those model runs are shown here. Under the different scenarios, we see vastly different evolution of the stock of water heaters between now and 2050. The lowest present cost evolution of the water heating stock for each scenario without gas installation charges is shown in Figures 3.2, 3.4, and 3.6. The results that include the gas installation charge in new construction are shown in Figures 3.3, 3.5, and 3.7. The results are very similar to the scenarios that do not include the gas installation charges in new construction. The one exception is that the "renewable and efficient" scenario would install more on demand gas water heaters in new construction if the gas install cost were not included. There is little difference between the cases that include the gas installation charge and those that do not because very little new gas is installed in new construction even in the cases without the gas install charge. We would expect a greater difference between the cases with a lower emissions constraint.

The notable features of these stock evolutions is that in the base case, heat pumps have already taken over the market in new construction in 2010 and begin transitioning in existing buildings in 2012-2013. In 2012 (without install charge) and 2013 (with install charged) we can see that the number of electric water heaters increases faster than the total stock increases. Since a gas to electric transition has

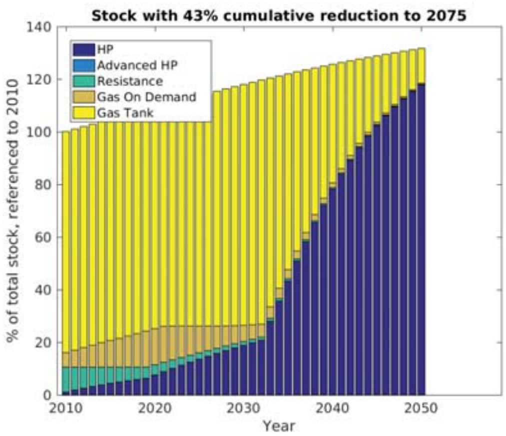

Figure 3.4: Evolution of building stock in "renewable and efficient" case

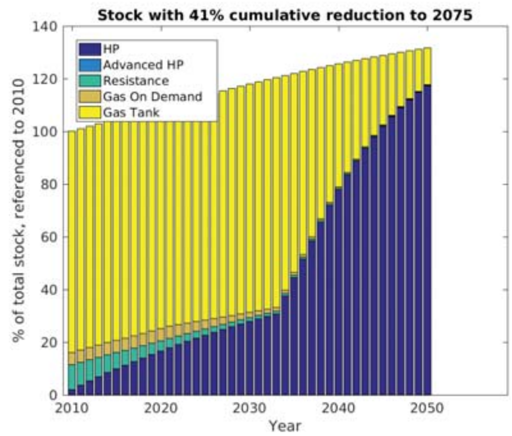

Figure 3.5: Evolution of building stock in "renewable and efficient" case, with gas install charge

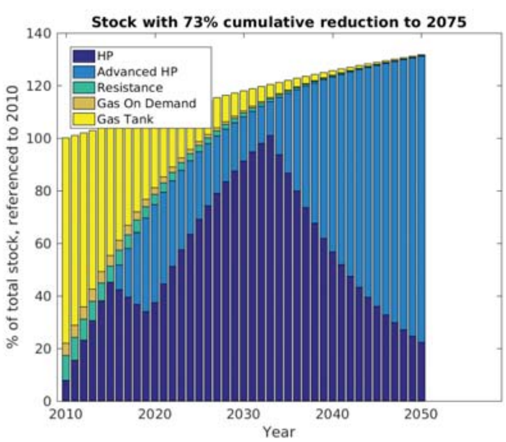

Figure 3.6: Evolution of building stock in "slower transition" case

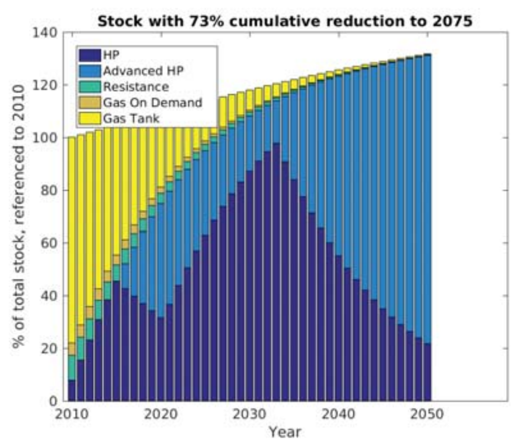

Figure 3.7: Evolution of building stock in "slower transition" case, with gas install charge

not actually happened yet, we would expect that the cost estimate of the base case is an underestimate of true cost to meet our emissions target. In the "renewable and efficient" case we see that heat pumps enter into new construction in 2020 (total electric stock increases at same rate as total stock), and begin to replace existing gas water heaters in the mid 2030s (electric stock increases faster than total stock). Finally, in the "slower transition" case, heat pumps again have taken over the market in new construction, and advanced heat pumps have also taken over a large market share starting in 2016. If we believe that we are in the base case or "slower transition" scenario, it is already too late to start installing heat pumps if we were cost minimizers. If however, we believe that more expensive, higher efficiency products will be required, hot water consumption will become much more efficient, and that we will indeed reach a 95% RPS in 2050, then it is still possible to get on the lowest cost pathway—but water heaters in new construction need to be entirely heat pumps by 2020.

Average cost per ton

Figures 3.2 through 3.7 show single snapshots of building stock changes that would meet a 90% reduction in 2050. But we can also show how adding a tighter and tighter emissions constraint can impact the average cost per ton. We calculate the cost per ton of CO_2 by dividing the change in total cost relative to an emissions-unconstrained baseline (for each scenario independently) by the change in total emissions relative to the unconstrained case. The results are shown in Figures 3.8, 3.10, and 3.12 for scenarios that do not include the cost of a gas connection in new construction. The same analysis is done including a charge for installing a gas connection in new construction. Those results are seen in Figures 3.9, 3.11, and 3.13. While the costs differ between scenarios, the shapes show some similar features. They all have a plateau at low reductions, a steep rise, a second plateau, and a final steep rise at high reductions. Upon investigating the stock changes in greater detail, we have found that the initial plateau reflects increasing the amount of on demand gas water heating and heat pump water heating in new construction. The first steep rise occurs when transitions begin to occur from gas to electric water heating, which incur transition costs. The middle plateau corresponds to earlier and earlier electrification, and the final steep rise corresponds to advanced heat pumps entering the market (this is a rough approximation, there are some differences between scenarios).

Marginal cost per ton

We can use this same data to estimate the marginal cost per ton. We estimate this by calculating the difference in cost and difference in emissions as the emissions

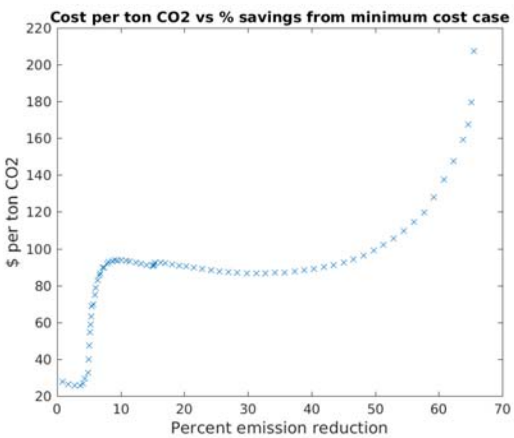

Figure 3.8: Average cost per ton CO_2 with different emissions constraints for the base case

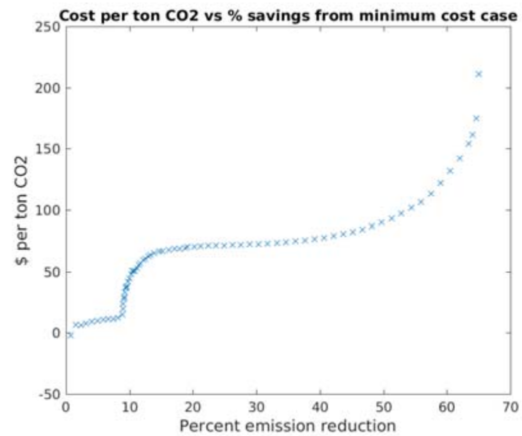

Figure 3.9: Average cost per ton CO_2 with different emissions constraints for the base case, with gas install charge

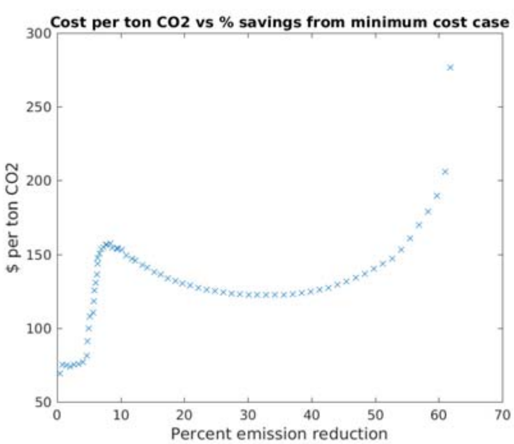

Figure 3.10: Average cost per ton CO_2 with different emissions constraints for the "renewable and efficient" case

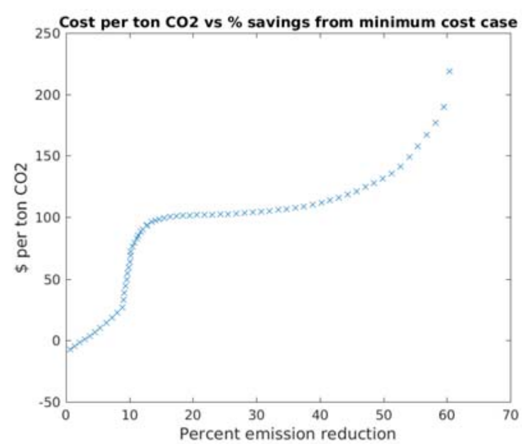

Figure 3.11: Average cost per ton CO_2 with different emissions constraints for the "renewable and efficient" case, with gas install charge

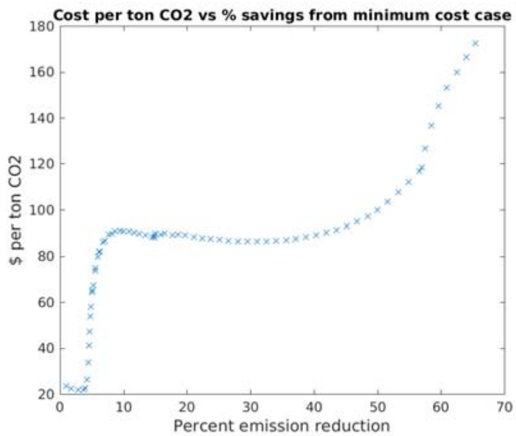

Figure 3.12: Average cost per ton CO_2 with different emissions constraints for the "slower transition" case

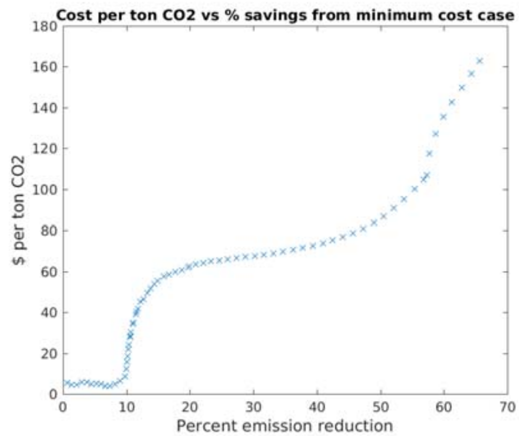

Figure 3.13: Average cost per ton CO_2 with different emissions constraints for the "slower transition" case, with gas install charge

constraint is tightened by 1%. The results from all scenarios are shown in Figures 3.14 through 3.18. All scenarios show a similar shape, with very high marginal costs for small (¡20%) reductions, then a middle range with marginal costs around $100/ton, followed by rising marginal costs at very high emissions reductions. As we observed in the average cost plots, the spike in costs with small reductions is a result of transitions from gas to electric far in the future. The optimization minimizes total cost, but it does not minimize cost per ton. As a result, small reduction goals lead to transitions to heat pumps far in the future, but since emissions are only counted between 2010 and 2050, these actions come at a very high marginal cost per ton. However, if the emissions reductions past 2050 were also accounted for, the marginal cost per ton would be lower for the cases that now appear to have a very higher cost. The higher marginal cost at very large reductions results from including advanced heat pumps.

Cost of delay

The first decision year in the model is 2010, but that is already in the past. There also is not currently a policy that will encourage widespread transition to heat pumps. The longer the transition is delayed, the more it will cost to reach the same cumulative emissions goal. By constraining the installations in early years to the existing mix of appliances, we can see how delaying electrification will lead to higher carbon prices. We also run the model with an additional constraint that fixes the market share of water heaters to the fractions in the stock that existed in 2009. The results of that

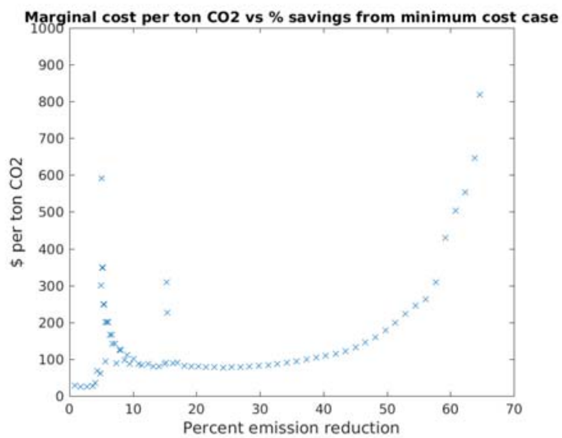

Figure 3.14: Marginal cost per ton CO_2 with different emissions constraints for the base case

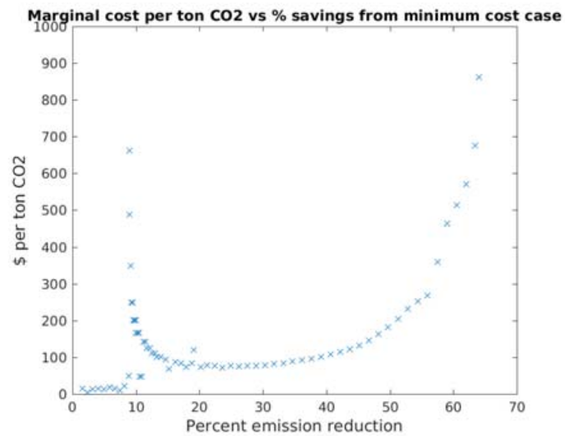

Figure 3.15: Marginal cost per ton CO_2 with different emissions constraints for the base case, with gas install charge

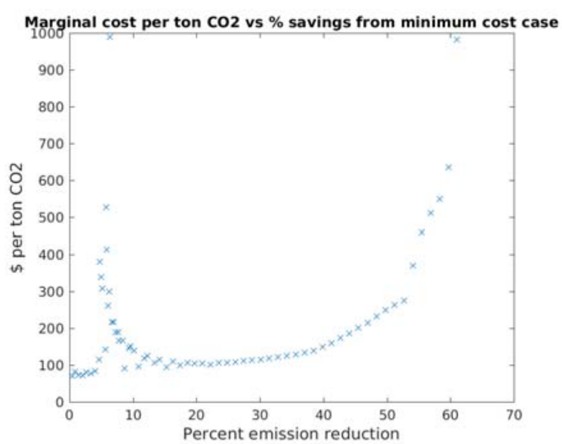

Figure 3.16: Marginal cost per ton CO_2 with different emissions constraints for the "renewable and efficient" case

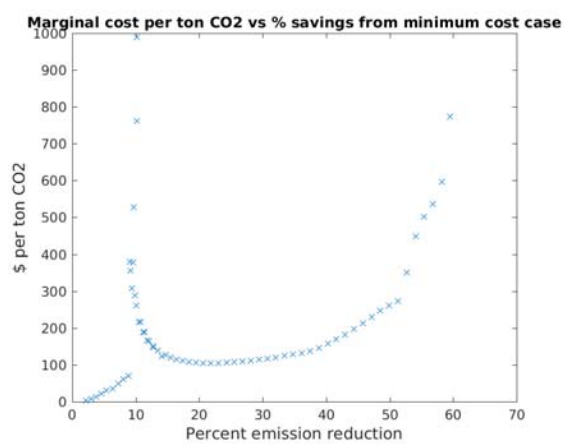

Figure 3.17: Marginal cost per ton CO_2 with different emissions constraints for the "renewable and efficient" case, with gas install charge

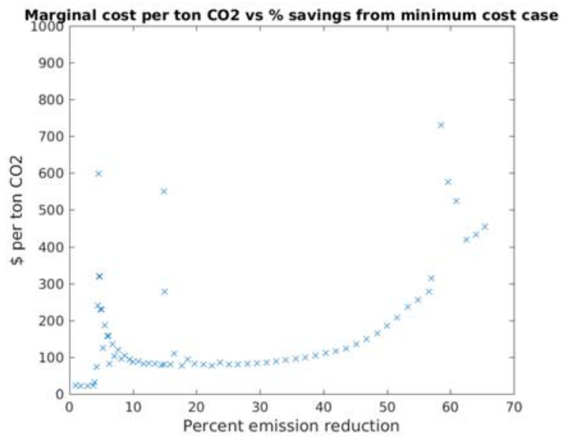

Figure 3.18: Marginal cost per ton CO_2 with different emissions constraints for the "slower transition" case

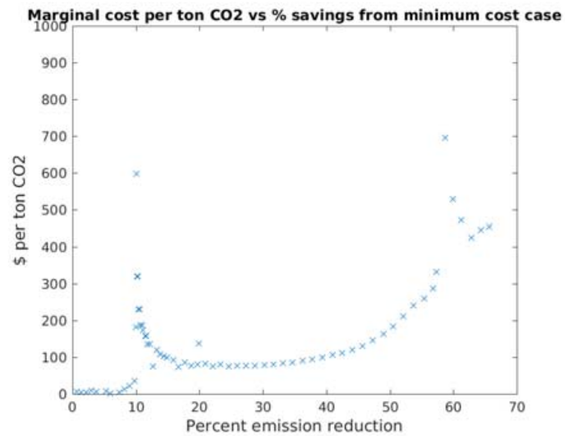

Figure 3.19: Marginal cost per ton CO_2 with different emissions constraints for the "slower transition" case, with gas install charge

analysis are shown in Figure 3.20. Where the lines end refer to the last year that action can be taken to meet a cumulative reduction goal in 2050, while also meeting a 90% target in 2050.

Comparison with a single year target

We have conducted a similar analysis that set a target of 90% emissions reduction in 2050, relative to 2010, but do not have a cumulative emissions constraint. In the original case we tightened a cumulative target until we also reached a 90% reduction in 2050. We would expect that if only a 2050 target were set, we would wait longer to transition to heat pumps, and that is exactly what we see in the results. In the base case and "slower transition" cases we see the impact that adding the gas install charge has on new construction. With the gas install charge added, all new construction since 2010 has heat pumps, and a transition in existing buildings begins between the late 2010s to mid-2020s.

Average costs

The average cost of emissions reductions varies for each scenario as seen in Table 3.4. The "base case" has the lowest cost: this is due to lower cost of appliances in the assumptions. While the "renewable and efficient" case includes more efficient appliances, they come at higher cost. To reach the 90% reduction in 2050, we would

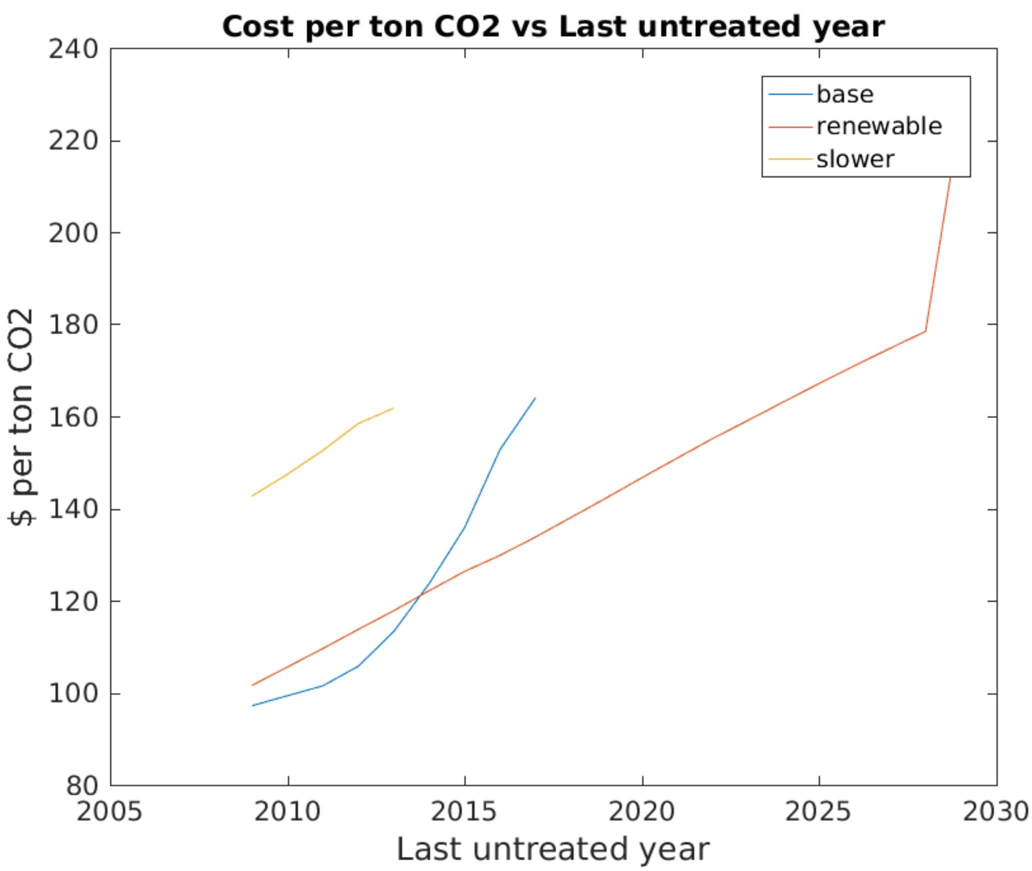

Figure 3.20: Average cost per ton CO_2 as transition is delayed in the base case, "renewable and efficient" case, "slower transition" case, with gas install charge

have to go further to the right on the plots shown in Figures 3.8 through 3.13 for the base case and "slower transition" case. Across scenarios we see a pretty narrow range of carbon costs, though far different timing of stock transitions.

Annual emissions

We summarize the results by showing the annual emissions trajectories result in all the scenarios that either include a 2050 annual target or a combined cumulative target and 2050 target as shown in Figure 3.27. All results are normalized to 2010 annual emissions in the unconstrained case. We see that using only an annual target results in higher emissions in the short term with rapid decline in the future. It is also

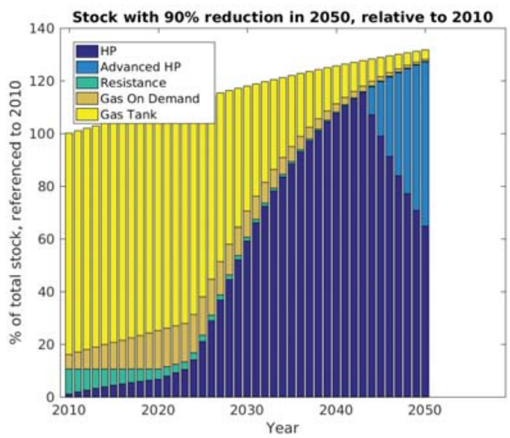

Figure 3.21: Evolution of building stock in base case, 2050 target only

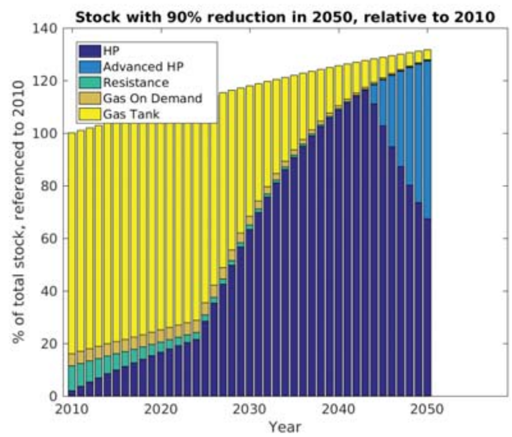

Figure 3.22: Evolution of building stock in base case, with gas install charge, 2050 target only

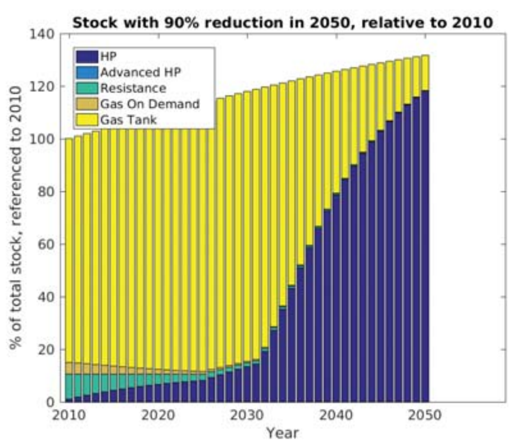

Figure 3.23: Evolution of building stock in “renewable and efficient” case, 2050 target only

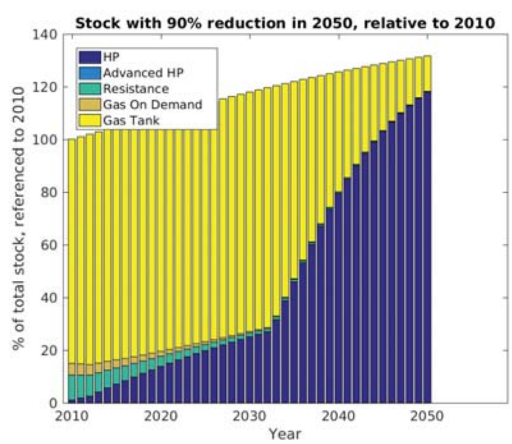

Figure 3.24: Evolution of building stock in “renewable and efficient” case, with gas install charge, 2050 target only

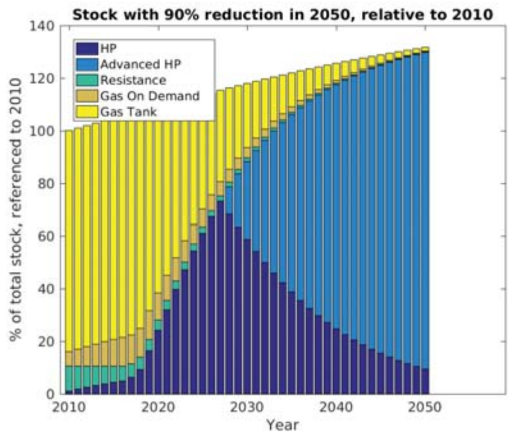

Figure 3.25: Evolution of building stock in "slower transition" case, 2050 target only

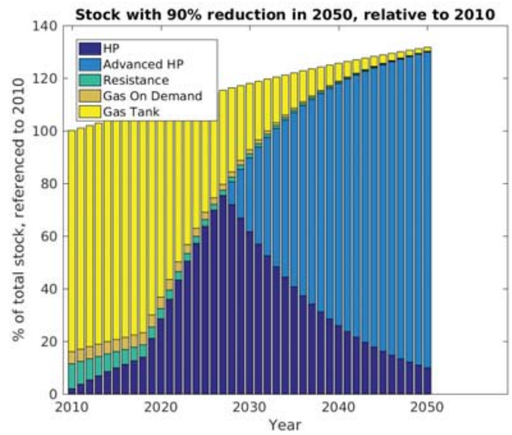

Figure 3.26: Evolution of building stock in "slower transition" case, with gas install charge, 2050 target only

Table 3.4: Cost per ton to meet 90% reduction in 2050

Scenario	Cost per Ton	Cumulative reduction	Cost per Ton w/ Gas install cost	Cumulative reductions w/ Gas install cost
"renewable and efficient"	$129	43%	$102	41%
"base case"	$110	68%	$97	66%
"slower transition"	$153	73%	$143	73%

Table 3.5: Cost per ton to meet 90% reduction in 2050, with 2050 target only

Scenario	Cost per Ton	Cost per Ton w/ Gas install cost
"renewable and efficient"	$139	$107
"base case"	$112	$99
"slower transition"	$144	$130

interesting to note that the “renewable and efficient” case with a cumulative target waits until the mid-2030s for this rapid decline. We can think of these scenarios outlining the approximate stock transition that policies should encourage, with the key lesson being that new construction needs to be electric now to minimizes the cost of reaching emissions goals. Existing buildings need to transition within the next decade, unless additional policies are put in place to require much more efficient water heating appliances.

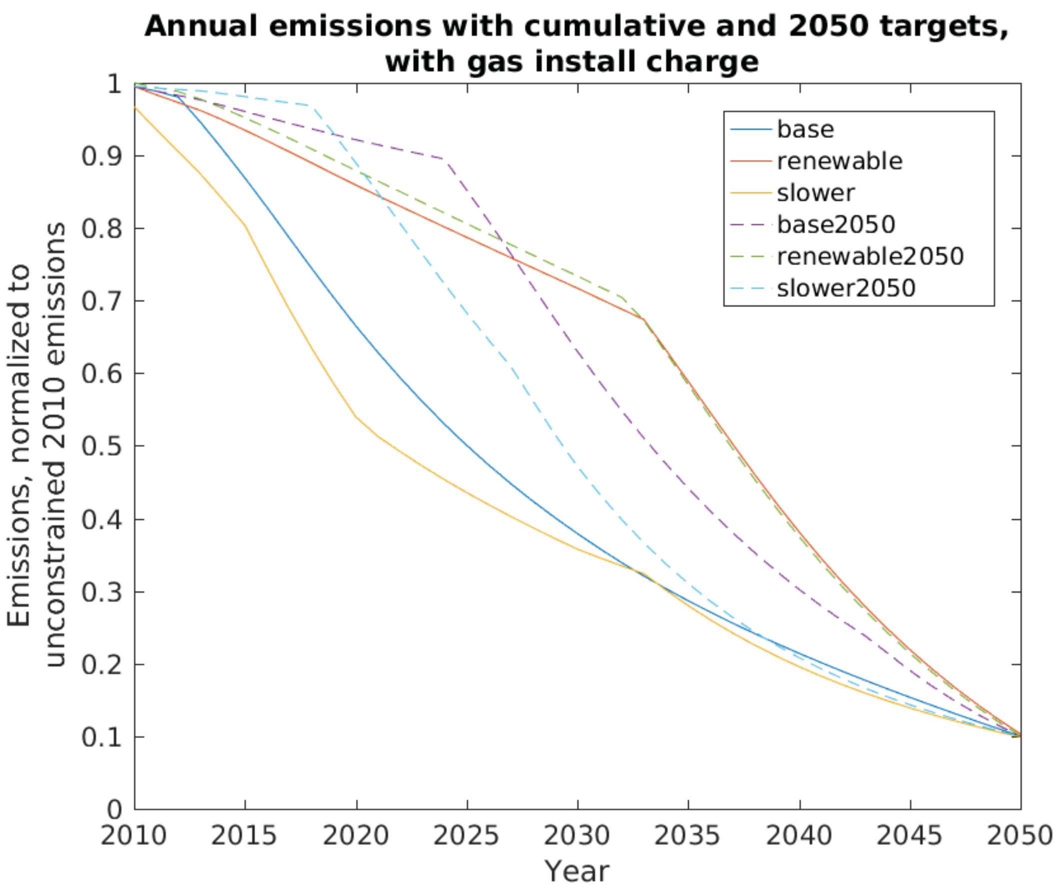

Figure 3.27: Comparison of emissions trajectories of the all scenarios with cumulative and 2050 targets.

3.5 Future work

One caveat of the results shown here is that, as a baseline, we assume that rational decisions are made. All decisions would favor the lowest lifecycle cost option, with a low (3%) discount rate. The cheapest technology to own and operate over the life of the equipment is installed. In reality, however, people use higher discount rates in their purchase decisions and will therefore opt for lower capital cost options than those presented here. Since the carbon price is calculated relative to the lowest cost case, it might not be accurate relative to the actually installed case. The actually installed case would have a higher total cost, and therefore the real carbon cost might be lower. That said, incentives that are funded through carbon pricing would need to incentivize changes in purchase decisions. Incentives that cover only the difference in lifecycle cost would likely be insufficient to motivate a transition to electrified water heating. Additional work could be done to better capture actual purchase decisions of irrational consumers.

We also have assumed that market for water heaters can transition overnight, in reality this transformation will take several years, and therefore the results shown here should be interpreted as showing the latest dates when a transition to electric water heating needs to occur to minimize costs. Future work could add additional constraints that limit how quickly the market can transition. Finally, we assume in this model that all consumers are average. In reality there is a distribution of water heating demand, and electrifying the high users will result in a lower cost per ton that the results have shown. Capturing this distribution of demand may result in far different outcomes.

3.6 Conclusion

The linear program that we developed has shown when a transition to electric water heating will need to occur and the approximate cost of this transition. Under the variety of scenarios that we have examined, we find that new construction needs to be electric immediately to reach emissions reduction goals at lowest cost, unless we increase efficiency standards on water heaters greatly. We also find that reaching a 90% reduction goal in 2050 is achievable at an average cost between \$100-150/ton. Policies need to be put in place soon to drive this transition if we are serious about reaching emissions reduction goals.

Chapter 4

Aligning California's building energy efficiency and climate goals

Preface

Currently a mismatch exists between emission goals and efficiency policy in California. In this chapter, I describe this issue in greater detail and propose actions that could be taken to allow for greater alignment between these goals so that both efficiency and climate goals can be met simultaneously. While the views presented here are my own, this work has benefited greatly from input from Pierre Delforge at the Natural Resources Defense Council.

Chapter Abstract

Current energy policies and economics give an advantage to natural gas appliances over electric appliances. Simultaneously, California's climate policy is aiming for very large reductions in emissions, which will either be impossible or costly without a phase out of many natural gas end uses. Aligning energy and climate policy is possible, but will require several changes. Some potential suggestions are offered in this chapter mostly related to changes to the building energy code. In addition to changes to building codes, other options are also possible such as designing electricity rates that properly reward flexible loads. Specific legislation may also be required to jump start a transition to electric heating. Such policies have been put in place in the past to support other technologies that may have even less climate benefit per dollar.

4.1 Introduction

Electrification of heating has clear climate benefits and likely will be necessary to meet long-term climate goals, but current energy policy in California is either hindering or, at a minimum, not supporting electrification. In this chapter we lay out this issue in greater detail and provide several policy options that could clear the path for greater electrification of space and water heating systems.

California's building energy code (Title 24) evaluates energy savings using a method that is misaligned with the State's long-term climate goals. The current Time Dependent Valuation (TDV) framework and carbon price it includes discourage solutions that can cost-effectively achieve the State's climate goals. In particular, TDV disadvantages solutions such as decarbonization of space and water heating that will be necessary to meet climate goals. A new or revised framework is needed that encourages adoption of measures that are necessary to meet long-term climate goals at lowest cost.

In the shorter-term, electrified appliances can also reduce operational costs in zero-net energy (ZNE) buildings, and they should be encouraged by the building code as a more cost-effective pathway to ZNE than mixed-fuel buildings. Various options should be explored, including changes to the existing TDV framework and completely different frameworks. The following non-exhaustive list of ideas is presented in this chapter:

1. Same-fuel baseline

2. Reexamine TDV adders

3. Controllable loads

4. TDV for self-generation
5. Alternative fuel price forecasts
6. Full societal cost accounting
7. GHG budgets
8. Count climate-beneficial electrification as efficiency to meet Senate Bill 350 goals
9. Rate design
10. Revise three-prong test
11. Legislation

First, it is necessary to explain the concept of Time Dependent Valuation because it is a key policy component that impacts electrification. Since 2005, Title 24 has used TDV in cost-effectiveness calculations. Electricity and gas have different values, depending on the hour of the year that they are used. TDV aims to capture this varying value so that efficiency measures that save energy at high value times are appropriately valued. In order to be code compliant, a building can use either a prescriptive or performance method. The prescriptive method sets standards for each building component, while the performance method looks at the modeled performance of a building. Most new buildings choose the performance method. In order to be code compliant through the performance method, a building must have better modeled performance than a standard building. This performance is based not only on how much energy is used, but when it is used—using TDV values.

4.2 Same-Fuel Baseline

The current Title 24 practice of comparing buildings that use electricity for heating with a budget generated from a standard (baseline) building using gas heating effectively uses the TDV metric to drive fuel choice. Given the current TDV framework, this results in penalizing electric options and incentivizing gas options. Such incentives run counter to emissions goals.

One simple solution would have the code compare proposed building designs with a baseline design using the same fuel as that of the proposed design: buildings with electric space and water heating would be compared with electric baseline designs, and buildings with gas space and water heating with gas baseline designs. This would simply align California's code with current practice in the International Energy Conservation Code (IECC).

Federal preemption might prevent the California Energy Commission from setting a 2.0 Energy Factor (EF) heat pump water heater (HPWH) as a baseline for electric water heaters. The alternative of using electric resistance water heaters as the baseline would encourage designs that are not cost-effective for consumers. One possible action to avoid the federal preemption concerns would be to set a whole-house all-electric baseline that does not specifically require a heat pump water heater.

While same-fuel baselines would remove some barriers to electrifying space and water heating, we also need to make sure that the code does not penalize partial electrification. In other words, if a customer or developer is ready to adopt some but not all electric technologies, for example water heating and clothes drying but perhaps not yet space heating and cooking, then the code should support these partially electrified buildings as well. This would accelerate the deployment of the most market-ready and cost-effective electric technologies, while the market further develops for the others.

Instituting a same-fuel baseline would level the playing field between fuels but would not necessarily align incentives with the State's climate goals. It would provide a short-term removal of one barrier to electrification until more fundamental changes to TDV can be implemented.

4.3 Re-examine TDV adders

Supplying energy has different costs, depending on when it is used. The purpose of TDV is to compare energy efficiency measures that save energy at different times and using different fuels. In theory, TDV will reward energy efficiency measures that save energy on peak over measures that save off peak. It also allows for comparison of measures that save electricity with those measures that save gas. The average level of TDV is set to match CEC price forecasts for retail electricity and natural gas. But in order to do this, adjustments are made to the TDV in the form of flat adders (rate adjustment and RPS adder) as seen in Figure 4.1.

This retail price adjustment and the RPS adder are components of the TDV that are added evenly across all hours, but it is unclear if these adders, which add about $90/MWh to the electricity TDV, should be added as constants. Clarification of what makes up these adjustments and if they actually are constant costs would be helpful in order to identify potential adjustments. If instead of constant adders, this adjustment were made with a multiplier, we would expect that more hours would have cost-effective operation of efficient electric heat pumps. There is a case to be

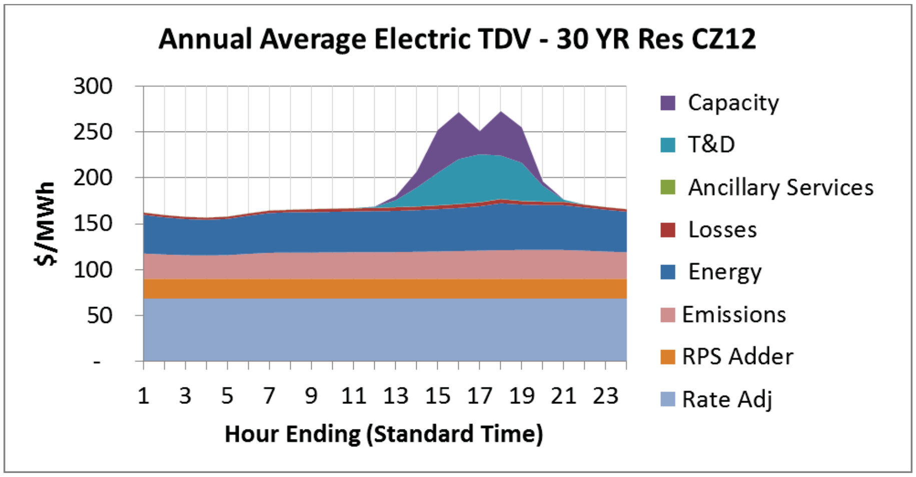

Figure 4.1: TDV components [77]

made that the costs of grid modernization for deeper integration of renewables, such as storage and demand response, should be allocated more heavily to peak hours, which a multiplier approach would do.

If such a change to the TDV methodology were logical and if modeling software allowed for controlled electric space and water heating loads, we could see more cost-effective electric heat (in operation) using the existing TDV framework. The analysis in Figure 4.2 below shows how, hour-by-hour, a 275% efficient (2.75 average COP) heat pump water heater would compare in operating cost to an 82% efficient (0.82 EF) natural gas water heater. Negative values represent hours when electric heating is cheaper than gas heating. The blue line uses existing TDV, while the red line adjusts the TDV to be more dynamic, removing the flat RPS adder and retail rate adjustment and instead adding a multiplier so that the average TDV remains unchanged. Without this TDV adjustment there are 3811 hours (44% of total hours) per year with cheaper electric heating. With TDV adjustment, we would see 4082 hours (47% of total hours) with cheaper electric heating. These hours come primarily in winter and in the evening which coincides with space heating loads and could coincide with some flexible water heating loads.

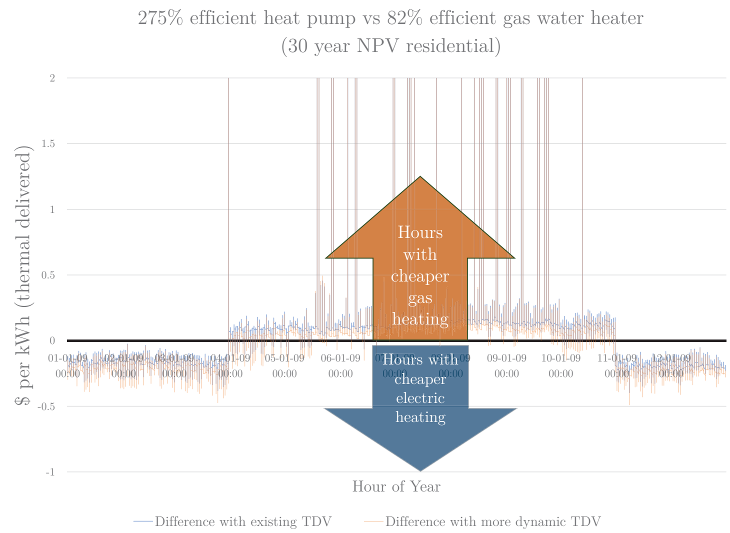

Figure 4.2: Sorted difference in operating cost for water heating. Positive values are hours with more expensive electric heating. The right figure shows the same values as the one on the left, without the highest 200 hours. A few very expensive hours make electric heating more expensive on average, though many hours are cheaper with electric.

4.4 Controllable loads

Sorting the values in Figure 4.2 results in Figure 4.3. We see a small number of hours (on the left side of the left graph of Figure 4.3) when electric heating is much more expensive than gas heating. But we also can see (on the right side of the right graph) that for many hours electric heating is cheaper.

Making TDV more dynamic makes it possible for electric heating to be cost-effective in more hours, but the main point is that electric heating, with existing technology, is already cost-effective (in operating cost) for about 1/2 of hours in a year. However, if we look at the average costs over all hours, then TDV would suggest that delivering a kWh of thermal energy costs 11.6% more with electric heating than gas. This is because of a few very high-priced electricity hours. By avoiding operation of water heating in 200 hours per year, electric water heating systems would match the operating cost of gas water heaters (in average TDV terms).

This simplified analysis is based on average water heater efficiency applied evenly across all TDV values, it does not match the specific load profile of heat pumps to the TDV profile. This simplified approach is used here to illustrate a concept: efficient, responsive electric heating can be cheaper to operate than gas.

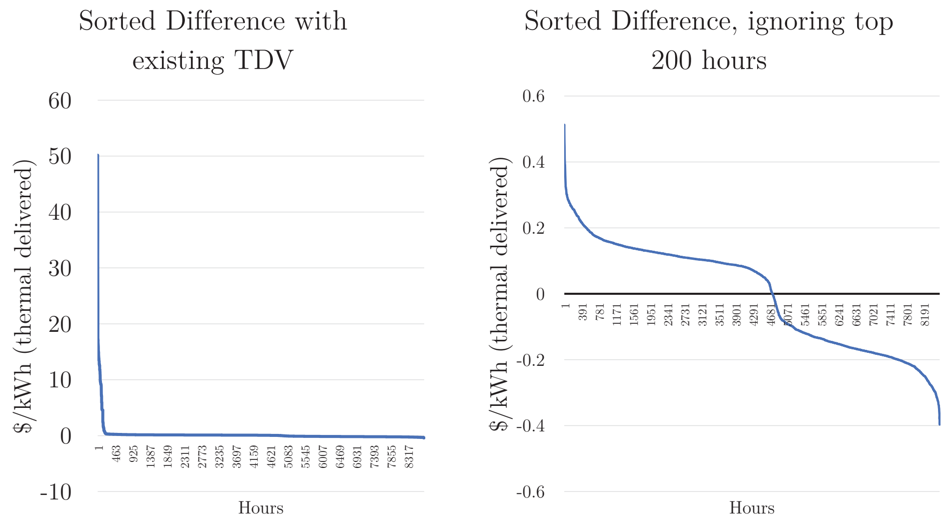

Figure 4.3: Comparison of TDV costs to deliver 1kWh of thermal energy using gas and electric water heating. Electric is cheaper in many hours, though more expensive on average due to some very high TDV hours.

Controllable loads will become more important as we transition from burning fossil fuels to using cleaner renewables like wind and solar. Variable resources, like wind and solar require "storage" to align supply and demand at all moments in time. By definition, energy storage is "the capture of energy produced at one time for use at a later time" [95] and is often employed to capture renewable energy when solar and wind resources are abundant for use when they are not.

Conventional wisdom suggests that energy storage captures electricity produced at one time for use as electricity at a later time. Because of that additional "as electricity" constraint, we typically limit ourselves to consider only those technologies that can deliver electricity when energy services are needed. These include batteries, pumped hydropower, flywheels, and supercapacitors. The problem is that energy storage is either very expensive (batteries, flywheels, supercapacitors) or limited in capacity and scalability (pumped hydropower).

Cheap energy storage would allow for higher penetration of renewables and reduce the price of clean electricity through higher utilization of generation assets. A recent study of the costs of reaching California's 50% renewable target finds that meeting these goals requires over-installing renewable capacity and allowing 9% of its energy (12 GWh annually) to be wasted or "spilled." Including 50 GWh of storage capacity reduces this spillage from 9% to 5% [96]. The faster we scale up storage, the faster we can add renewables to the grid without having to spill energy. And the faster that we can do that, the faster we can reduce greenhouse gas emissions and avoid climate change.

By expanding the energy storage definition to include anything that captures energy produced at one time to deliver an energy service at a later time, many other storage options become available. Preheating and precooling buildings to provide comfort later is energy storage. Heating up water when electricity is produced for a hot shower later is also energy storage.

Traditionally, hot water heaters are controlled by sensing the water temperature in the tank. When that temperature drops below a threshold, the water heater runs until a higher temperature threshold is reached. This control strategy ignores the demand for hot water, the price of electricity, current emissions from generators, and the real time needs of the electricity grid. Utilities are starting to provide incentives for consumers to change when they consume energy by applying time varying rates for electricity (known as time-of-use pricing), but we need to make it easy for consumers to respond to these changing prices. Smart devices enable consumers to shift their load to low price times, thus reducing their overall energy bill.

As we have shown, avoiding just a handful of hours of operation can lead to electric water heating being cheaper than gas in TDV terms today. Beyond this simple strategy, a more detailed control strategy could lead to lower costs.

The magnitude of this storage opportunity is huge. In the United States about 40% of houses have electric hot water heaters, or about 47 million housing units [56]. These units represent a tremendous potential of energy storage. Consider this: a 50 gallon hot water tank with water at 140F is storing 2.5 kWh more energy than a hot water tank at 120F, but both can deliver a comfortable shower. If the tank were heated to 140F once per day when electricity is cheap and available and allowed to drift down to 120F once per day when electricity was scarce, then a smart water heater would have stored and discharged 2.5 kWh that day. Across all 47 million houses over the course of year, smart water heaters could store up to 43 TWh if they performed this storage action daily. For comparison, all utility-scale renewable generation, including hydropower, produced 609 TWh of electricity in 2016 [97]. In other words, intelligently controlling existing electric hot water heaters once per day could store 7% of the existing generation from all renewables—and it is certainly possible that multiple daily charge/discharge cycles could be used which would further increase the total storage potential.

4.5 TDV for self-generation

TDV currently reflects a conventional centralized electricity generation model. But as distributed energy resources become more common and continue to ramp up as California implements Zero Net Energy (ZNE) requirements in the 2019 building code, TDV as currently calculated does not adequately represent consumer cost for self-generation customers (e.g. rooftop PV). Self-generation, particularly in the context of ZNE where the PV system is sized to offset the building's entire energy use, changes the cost of energy in three ways: 1) The cost of self-generated electricity is lower and fixed: With the rapidly declining cost of rooftop PV, a customer who installs a rooftop PV system locks in an electric rate that is lower than the average retail rate right from the start and remains constant over the life of the system. Solarized customers therefore have access to electricity that is significantly cheaper than CEC's forecast of future retail electricity price. And as the cost of PV systems declines further, electricity from those systems will continue to become cheaper. If the framework used to evaluate decarbonization options for space and water heating remains solely focused on customer cost-effectiveness, it should take into account the real retail price of electricity for solarized customers. 2) High-efficiency all-electric appliances can reduce the size of the PV system required to achieve ZNE: To achieve ZNE, a building will be required to offset its fTDV energy use with onsite generation such as rooftop PV. Offsetting energy use in a mixed-fuel building for a typical single-family home with a 2016-code compliant envelope requires 5 to 7 percent more PV than in an all-electric home with high-efficiency heat pump appliances [98]. This represents roughly an extra \$1,200 to \$1,500 in PV installed cost (at 2015 cost of \$3.50 per watt). 3) The homeowner receives net surplus compensation: In a mixed fuel building, the output of the PV system that offsets the gas portion of the building's energy use exceeds the net electrical use of the building and therefore is sold back to the utility at a low net surplus compensation rate (between \$0.03 and \$0.04 for PG&E) [99]. This compares with an average rate of \$0.17 for avoided electricity use when all PV energy can be self-consumed. This represents a loss (extra cost for the consumer) of roughly \$375 annually in the same typical SF home as above. Points #2 and #3 significantly increase the cost of achieving ZNE in mixed-fuel buildings relative to all-electric buildings. This cost difference is not represented in TDV, which does not account for self-generation and for the fact that ZNE buildings are required to size their PV systems to offset both their electric and their gas energy use. To fix this issue and help Californians achieve ZNE at the lowest cost and carbon footprint possible, a new "self-generation TDV" needs to reflect the consumer cost of self-generated electricity (fixed over the life of the PV system) as well as the grid costs to support the net electricity imports/exports of the building.

4.6 Alternative electrification price forecast scenarios

In order to meet 80% reduction goals for 2050, emissions from combustion of fossil natural gas in the residential sector will need to be dramatically reduced. However, current forecasts of gas and electricity prices suggest that, while electricity is a cleaner heating fuel when used in a heat pump (and will continue to become cleaner), it is also higher cost. Electrification of heating loads is not accounted for in long-range forecasts for gas and electricity. If it were, we might see retail gas prices go up to cover fixed infrastructure costs with lower sales volume. Natural gas utilities have large fixed costs to install and maintain gas pipeline networks and these costs are recovered largely through volumetric charges on customers' bills. These costs may make up more than a third of the total retail gas price today. With reduced gas sales as customers electrify heating, this portion of the bill would have to increase for the remaining gas customers. Gas commodity prices also may decrease following reduced demand, the net impact of these conflicting pressures needs to be evaluated.

While the TDV methodology determines valuations on an hourly basis, it aims to fit the average value to the CEC price forecast. On the margin, electric heating does not look particularly attractive (using the average TDV, see above). But, when we look at a scenario with a high penetration of electric vehicles and flexible electric heating that increase load factor, lower retail natural gas demand, and a carbon price that is sufficient to meet 2050 goals, it is possible that efficient electric heating would be much more cost-effective than current forescasts suggest. The positive feedback loops, such as lower installed cost as heat pump market share grows, lower electricity prices as the load factor increases, and higher per unit gas delivery charges, could further accelerate economic attractiveness of electrifying. The CEC could perform a fuel price forecast for a scenario with decreasing residential demand for gas and increasing and controlled demand for electricity for space and water heating and electric vehicles. Accounting for these flexible, currently available technologies that can avoid consumption on peak and increase consumption off peak is important to fairly compare gas and electricity end uses.

Finally, it is worth noting that forecasts are highly uncertain, but the way that forecasts are currently used gives them tremendous influence on fuel choice. By using them for major—and long-lasting—building design decisions, we perhaps give them more impact than they really deserve. When those forecasts drive higher emission decisions, we should proceed with caution. TDV has a large impact on design decisions, and underlying the TDV is an estimate of future retail gas and electricity prices. Those relative future price estimates are, on average, insufficient to drive the transformation of heating that is necessary to meet emission goals.

4.7 Full societal cost accounting

Over the long term we should account for the full societal cost of electric and gas heating. The Title 24 framework should make it possible to compare social costs and benefits of decarbonized heating options. Doing so could illustrate the most cost-effective pathway to 2050 and show how the social cost of carbon might vary for different levels of abatement. Some measures may be cheap on a per ton basis (improved gas water heater efficiency) up to a limited extent, but they may be cost-prohibitive to achieve the decarbonization levels required to achieve deeper decarbonization goals. Focusing on short-term cost may not provide the most cost-effective long-term pathway.

Performing such full societal cost accounting is challenging because 1) it may be beyond CEC's current authority under Warren-Alquist, although this question merits further legal analysis; and 2) it is difficult to accurately evaluate the societal cost of electricity and gas. This cost depends on many variables, such as the pace of the transition (the earlier we start, the cheaper it likely will be to achieve cumulative reduction targets) and the choice of solutions (locking in emissions and investing in infrastructure that may become stranded before the end of its life will increase the overall cost). But just as the current TDV framework is based on future customer price projections, a framework using societal cost could be developed based on the best available projections of the societal cost of achieving California climate goals under a variety of scenarios.

4.8 GHG budgets

Rather than using a cost-based metric to evaluate building performance, we also should explore creating a GHG-emissions metric, where each building is given a GHG budget that must be met. This could be standalone, or blended with something similar to the current TDV cost metric. This option may go beyond CEC's authority from the Warren-Alquist Act to focus on cost-effectiveness, but it merits further legal analysis.

4.9 Count climate-beneficial electrification as efficiency to meet Senate Bill 350 goals

Senate Bill 350 sets a target of doubling end-use energy savings from energy efficiency by 2030. This goal doubles the savings, relative to "additional achievable energy efficiency savings." The bill states that aggregation of savings is possible between electricity and natural gas, meaning that savings above the target for one energy type may be counted toward the target of the other type. Several different methods could potentially be used, each of which keeps a specific metric constant through aggregation. Aggregation could potentially be based on site energy, source energy, greenhouse gas emissions, or some combination. Aggregation is important in order to capture the most cost effective opportunities first. A transition away from gas and toward electricity for heating end uses will result in larger than expected gas savings and smaller than expected electricity savings. The aggregation framework should allow and encourage this transition if it results in lower net greenhouse gas emissions.

4.10 Revise three-prong test

The Energy Efficiency Policy Manual states that programs that encourage fuel substitution must show that projects do not increase source energy consumption and must have Total Resource Cost and Program Administrator Cost ratios of 1.0 or greater (they must be cost effective). Fuel substitution also must not "adversely impact the environment" [100]. While it can be shown that electrification does not adversely impact the environment, it may be more challenging to show cost effectiveness or that it does not increase source energy consumption. As a result of this policy, it is difficult or impossible to use energy efficiency program dollars on projects that encourage fuel substitution in either direction. The language of the test needs to be clarified and updated to reflect the current reality that source energy metrics are less meaningful with large fractions of renewables. The cost effectiveness tests should also be applied across portfolios of energy efficiency projects.

4.11 Rate design

The economics of electrification make it challenging to make the case for fuel-switching in existing homes. The equipment has higher upfront costs than gas options and they also currently cost more to operate. In Figure 4.4 we show if a gas or electric water heater would be cheaper to operate for any combination of fuel prices. This assumes a gas water heater with an energy factor of 0.82 and an electric heat pump water heater with an average COP of 2.75. The red box also identifies the current range of standard residential gas and electricity prices for Pacific Gas and Electric. We see that with current rates gas is generally the cheaper option. In order to spark a transition to electric heating, new rates will need to be introduced that make electric heating cheaper. This is not entirely new; electric vehicles are already eligible for lower rates, and current EV rates would be sufficient to make water heating cheaper to operate than gas.

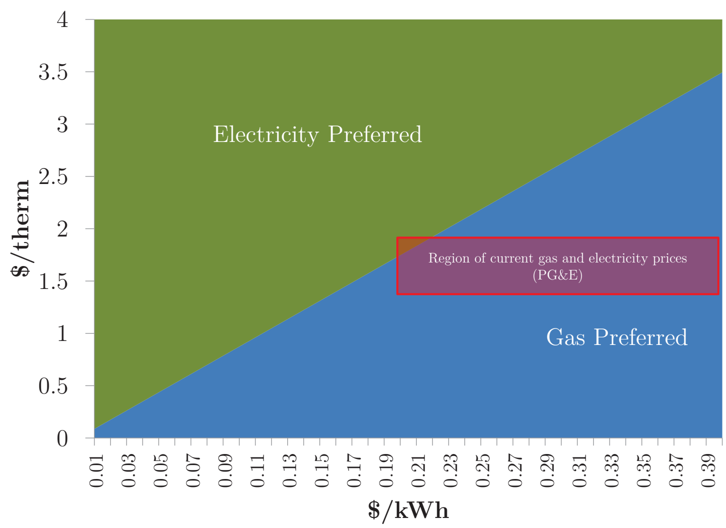

Figure 4.4: Regions with different preferred fuel types.

4.12 Legislation

In addition to redesigning rates, electrification will require funding to cover the transition costs and incremental costs of electric appliances over gas appliances. If energy efficiency program funds cannot be used to fund these subsidies, additional legislation could be helpful to fund these incentives. Past incentive programs, such as the California Solar Initiative (CSI), may serve as an example of programs funded by legislation that would not have otherwise passed cost effectiveness tests. The CSI program for solar water heating had costs of saved natural gas far higher than retail rates and also far higher than we would expect for heat pump incentives. Covering the one time transition costs for electrification in existing buildings and the price premiums of heat pumps over gas systems could expand the heat pump market and drive down future costs.

4.13 Accelerate market transformation

While electrification of space and water heating is theoretically possible, transforming the market will have many challenges. Appliances are generally replaced with something similar to what was installed and/or what the installer has readily available. In order to transform the market, installers will need to become more familiar with heat pump and have confidence in their performance. Since replacement decisions are typically make after failure has already occurred, consumers tend not to spend very much time on the decision. The decision to electrify heating needs to be integrated with other decisions about energy systems in the home. For example, if a house installs solar panels, and electric vehicle, or a battery then the home should also be made electric-heating-ready. These transition costs can be much lower if an electrician is already on site. And if a gas water heater is already close to the end of its life, replacement can be done proactively before failure. New construction should be required to be wired for electric space and water heating to minimize future costs. One of the most common barriers to electrification is cooking. Cooking with gas is commonly preferred, and while it is a small end use of natural gas, eventually it will need to be addressed. It is a more immediate challenge in new construction to convince developers to forgo the installation of a natural gas connection. A greater marketing effort will be required, possibly by celebrity chefs, to show the positive qualities of induction cooktops.

4.14 Conclusion

Decarbonizing space and water heating is necessary to meet emissions goals, but current energy efficiency policies at worst stand in the way and at best do not encourage electrification. Here we have presented a handful of policy options to address these shortcomings, though many other strategies might also be useful. Fundamentally, a carbon price adequate to reduce emissions 80% by 2050 would be the most straightforward way to encourage electrification. Passing on this carbon price through retail rates of electricity and natural gas would eventually encourage consumers to transition to electric technologies. However, relying only on this approach may not deliver the desired emissions reductions fast enough, as there are long lags between observed energy prices and changes in purchase decisions of space and water heating appliances. In addition to policies that target the economics of electrification, we also will need to gain a better understanding of the behavioral challenges that may also stand in the way. Adoption of unfamiliar technology has a high perceived risk of failure. Education, incentives, and guarantees will all need to play a role to convince consumers to electrify. Planning for this market transformation is critical in order to meet emissions reduction goals.

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Appendix A

Implications of electrifying residential space and water heating

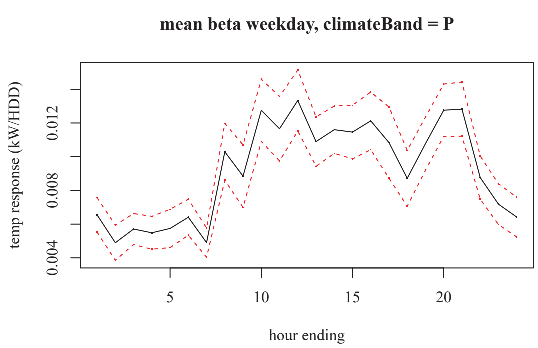


Figure A.1: β estimates for climate band P, weekdays

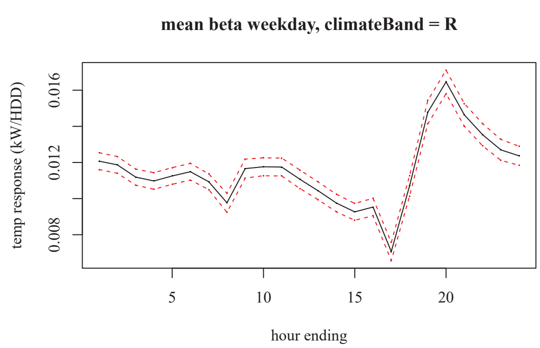


Figure A.2: β estimates for climate band R, weekdays

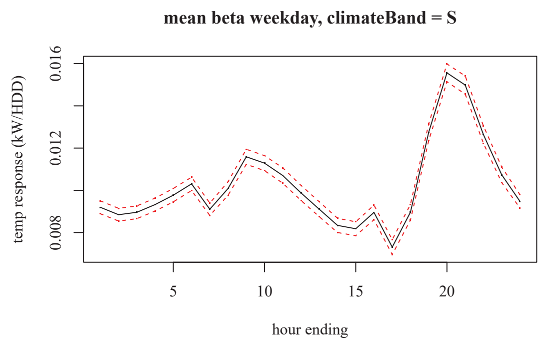


Figure A.3: β estimates for climate band S, weekdays

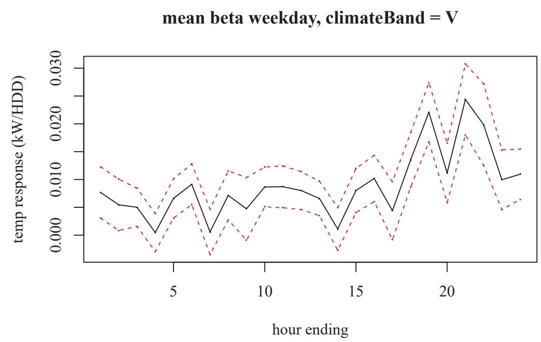


Figure A.4: β estimates for climate band V, weekdays

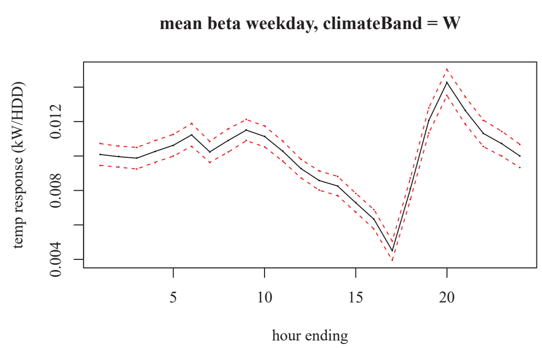


Figure A.5: β estimates for climate band W, weekdays

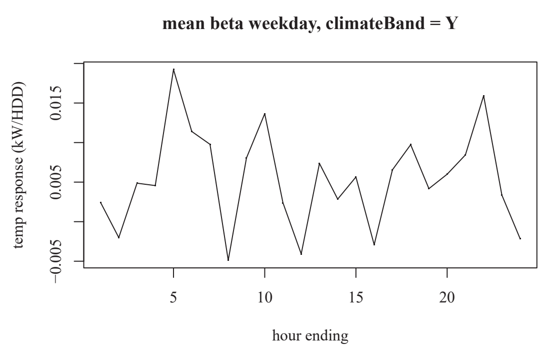


Figure A.6: β estimates for climate band Y, weekdays

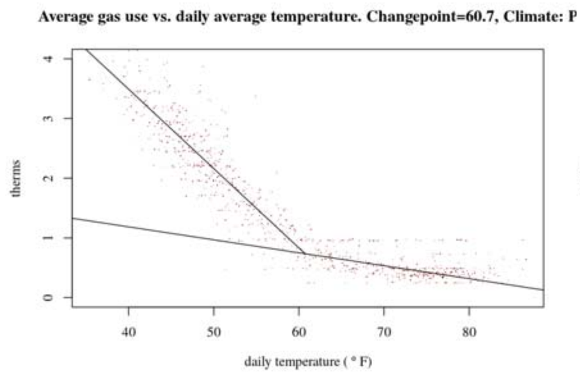


Figure A.7: Piecewise regression of gas use on temperature, climate band P

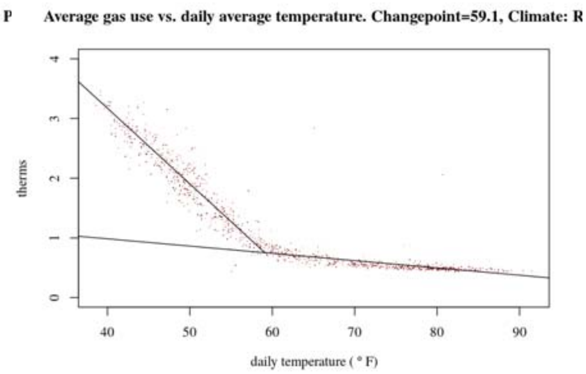


Figure A.8: Piecewise regression of gas use on temperature, climate band R

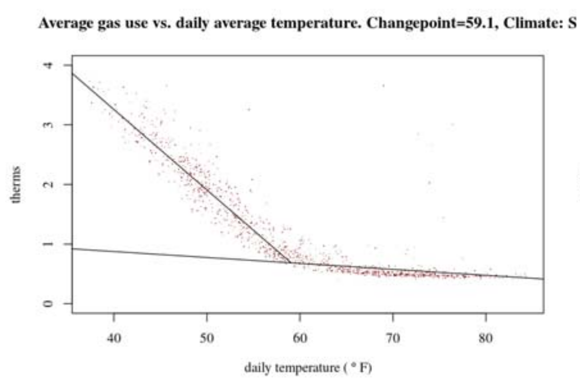


Figure A.9: Piecewise regression of gas use on temperature, climate band S

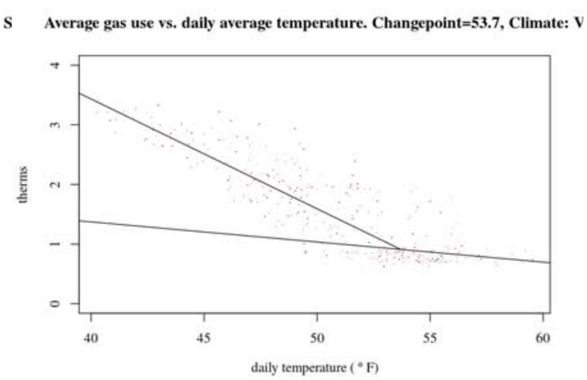


Figure A.10: Piecewise regression of gas use on temperature, climate band V

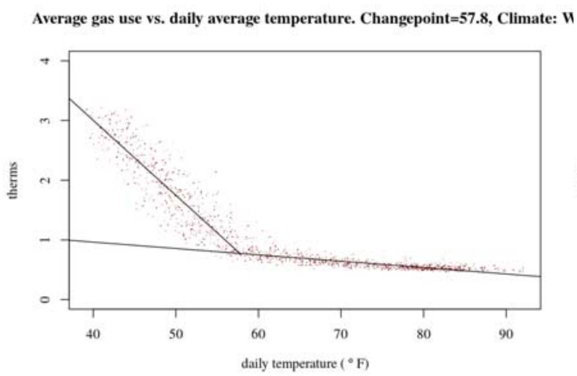


Figure A.11: Piecewise regression of gas use on temperature, climate band W

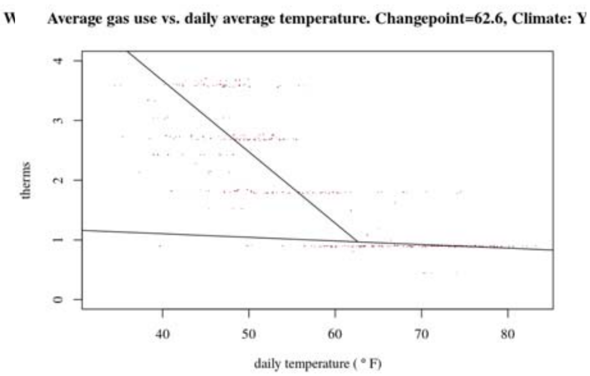


Figure A.12: Piecewise regression of gas use on temperature, climate band Y

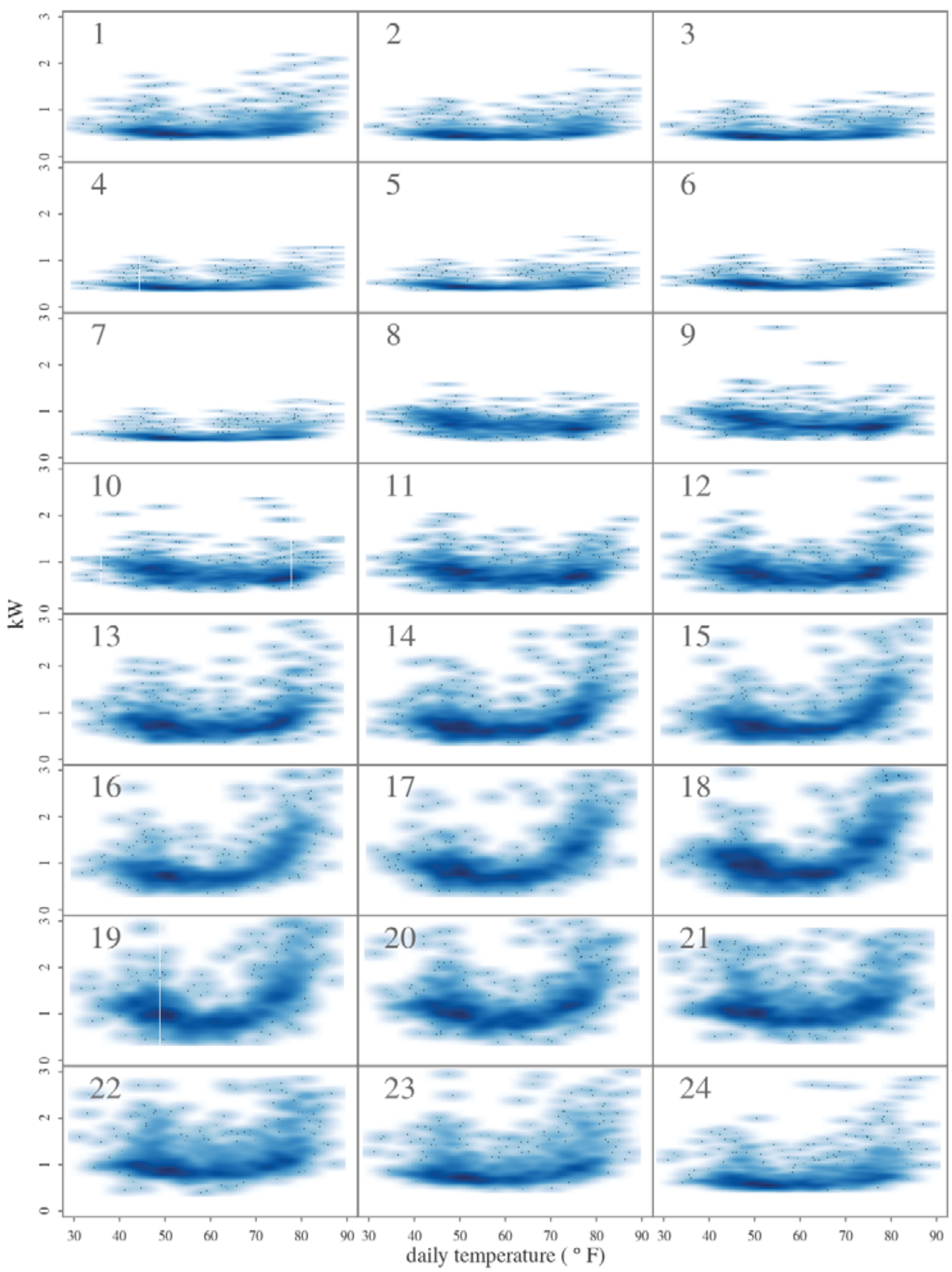


Figure A.13: Electricity use vs temperature split between hour of day, climate band P.

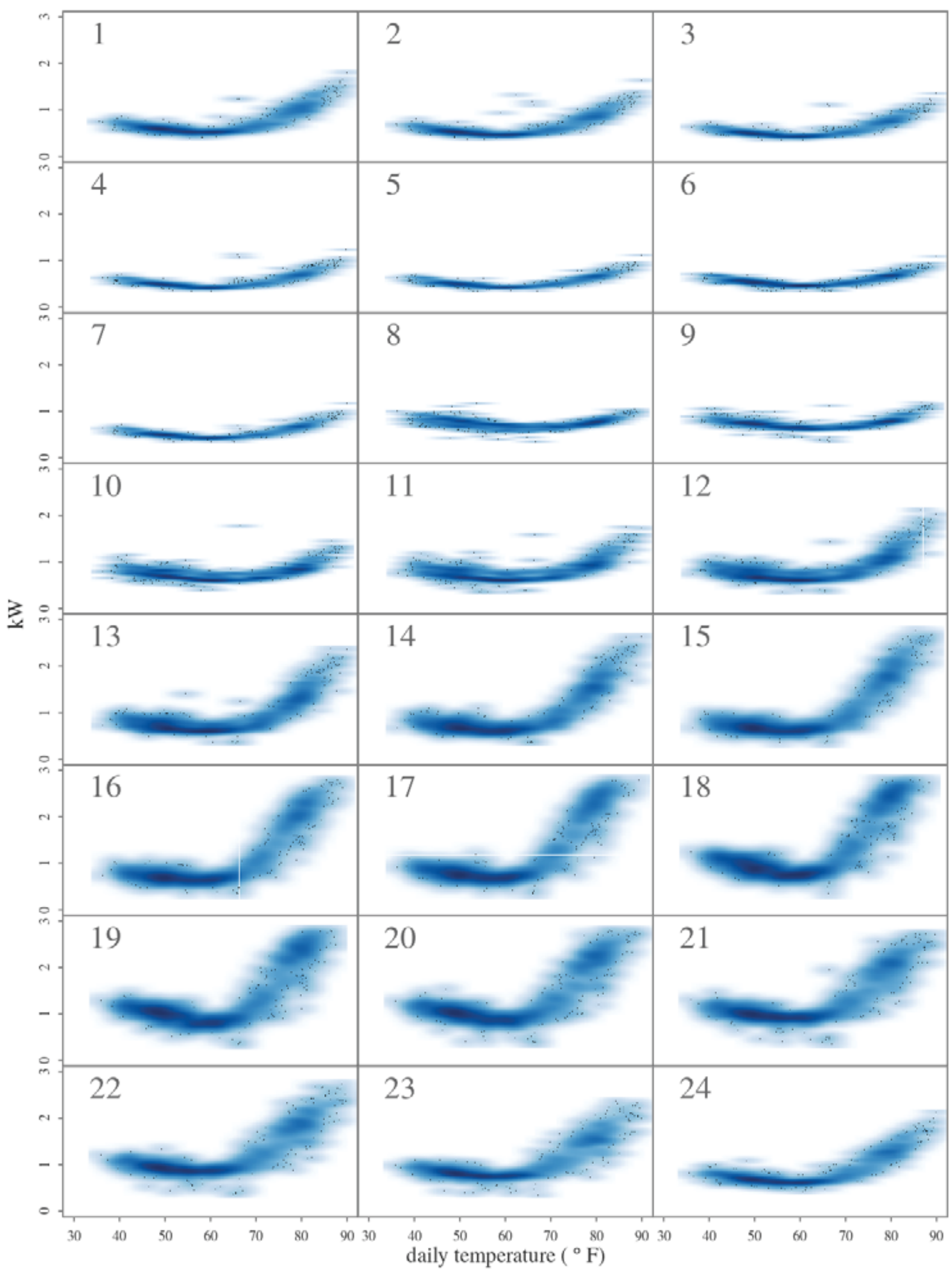


Figure A.14: Electricity use vs temperature split between hour of day, climate band R.

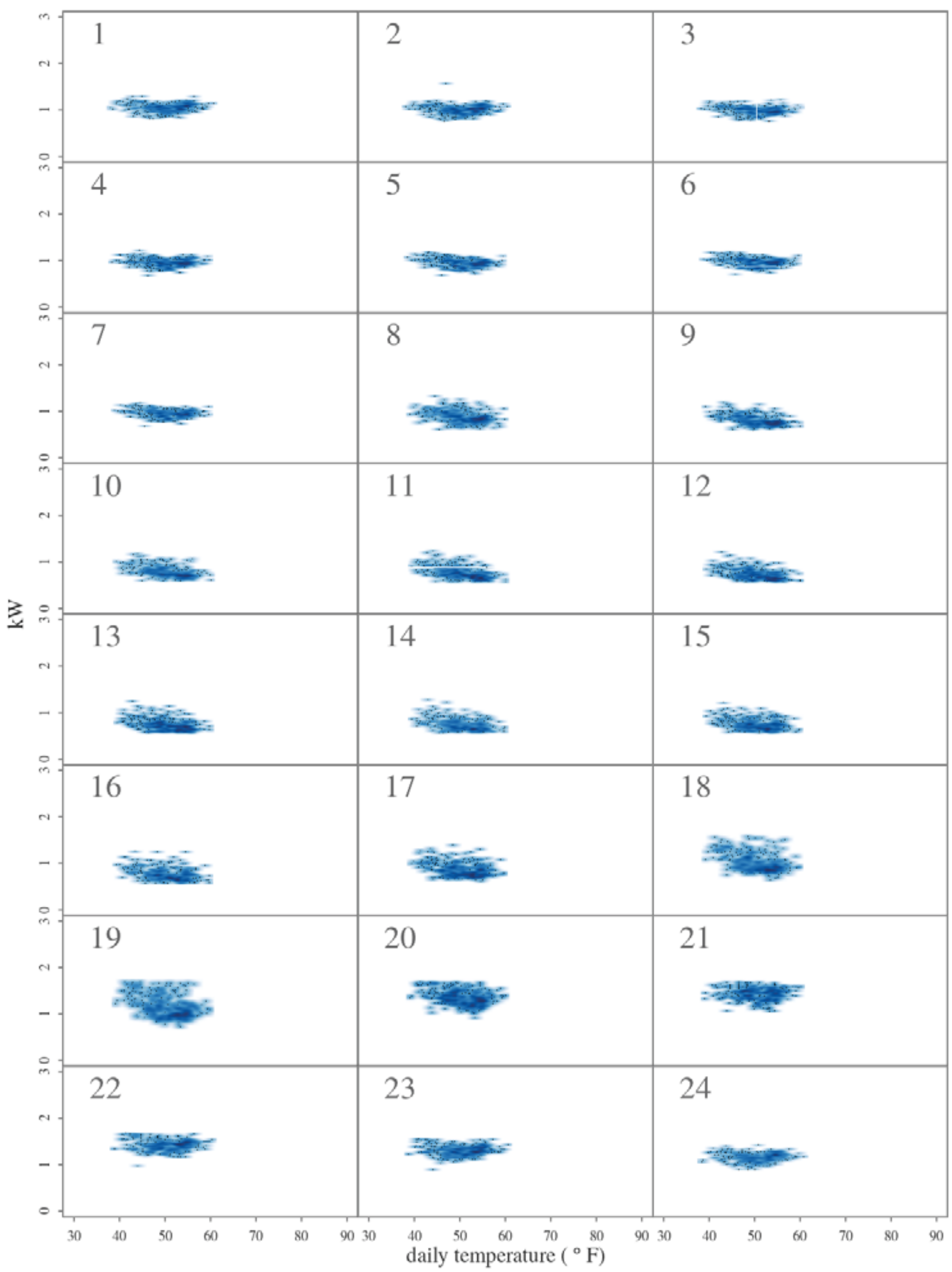


Figure A.15: Electricity use vs temperature split between hour of day, climate band V.

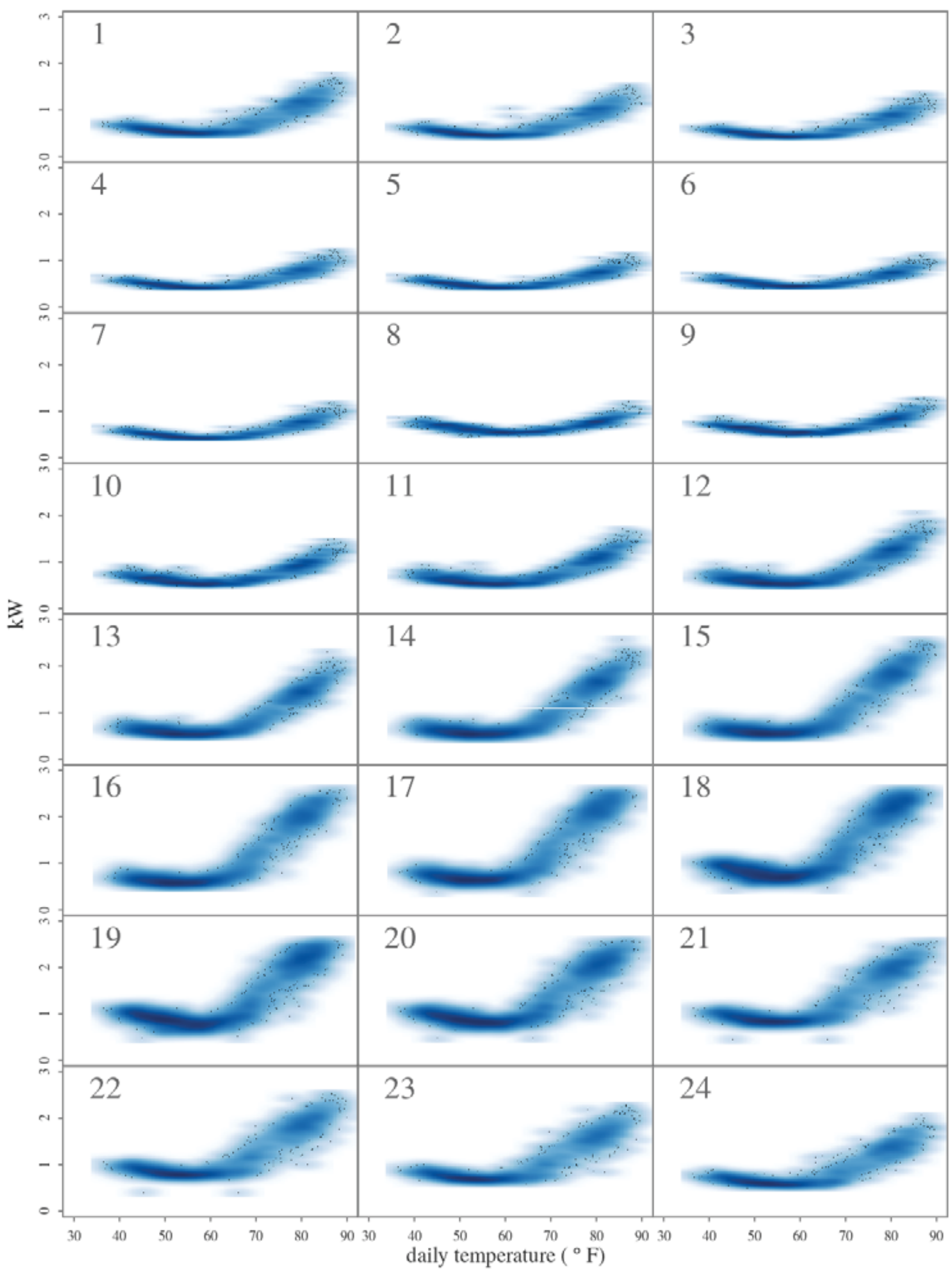


Figure A.16: Electricity use vs temperature split between hour of day, climate band W.

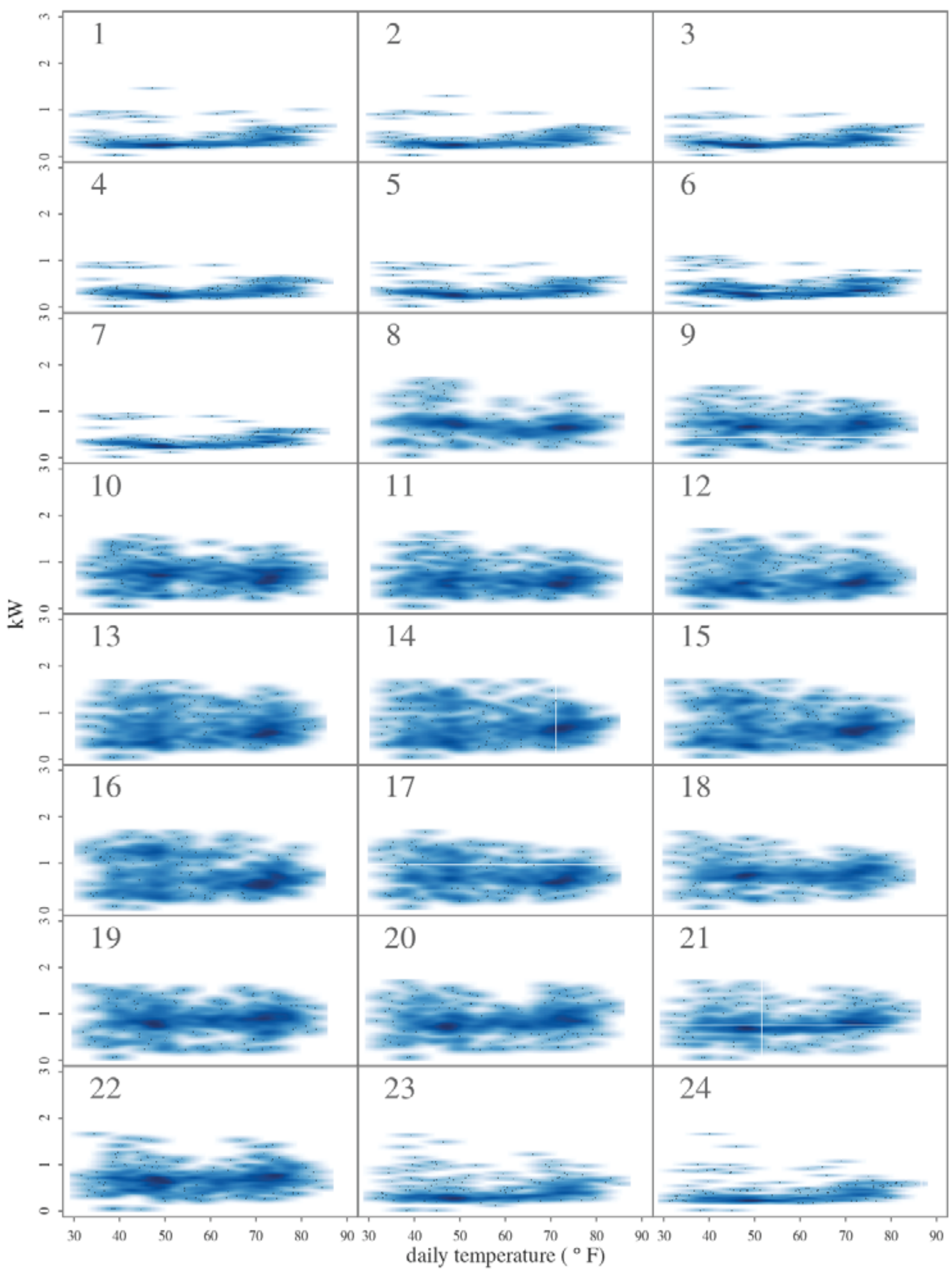


Figure A.17: Electricity use vs temperature split between hour of day, climate band Y.

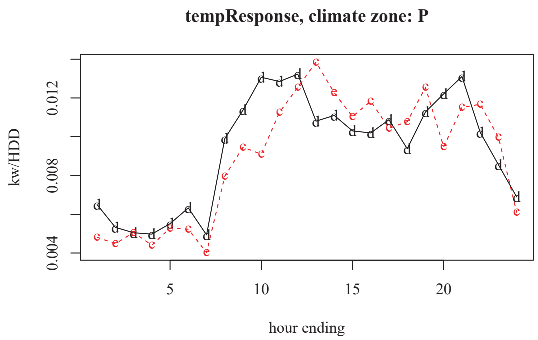


Figure A.18: Estimates of β_{HOD} for weekdays (d) and weekends (e), climate band P

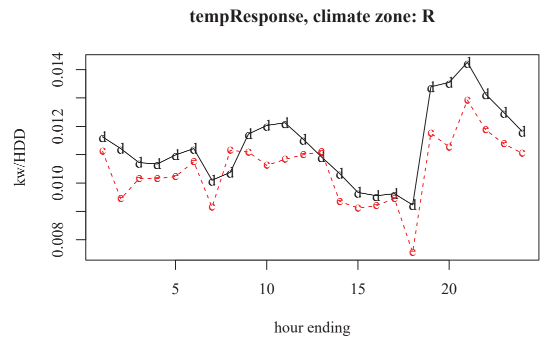


Figure A.19: Estimates of β_{HOD} for weekdays (d) and weekends (e), climate band R

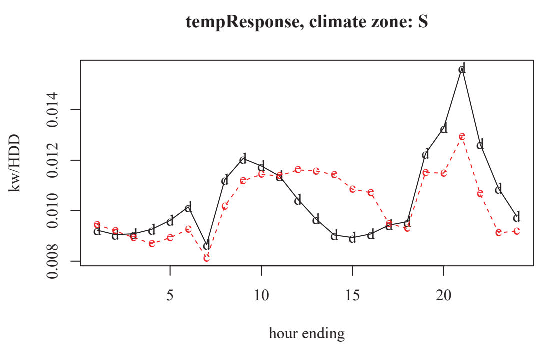
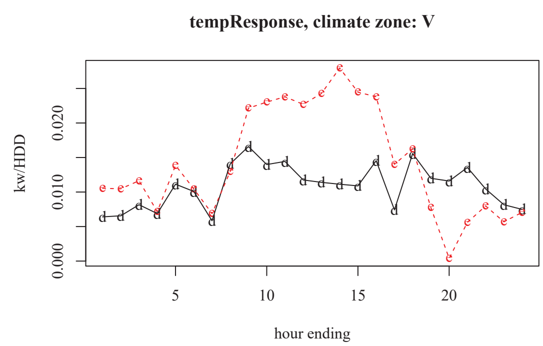


Figure A.20: Estimates of β_{HOD} for weekdays (d) and weekends (e), climate band S



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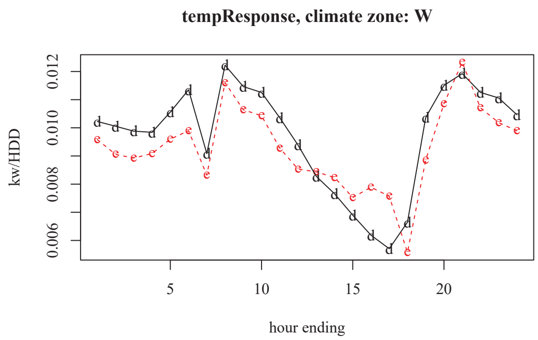

Figure A.22: Estimates of β_{HOD} for weekdays (d) and weekends (e), climate band W

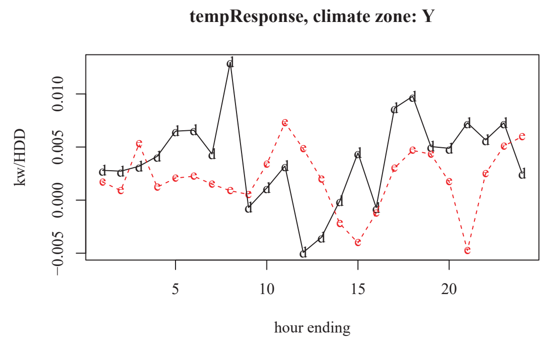

Figure A.23: Estimates of β_{HOD} for weekdays (d) and weekends (e), climate band Y

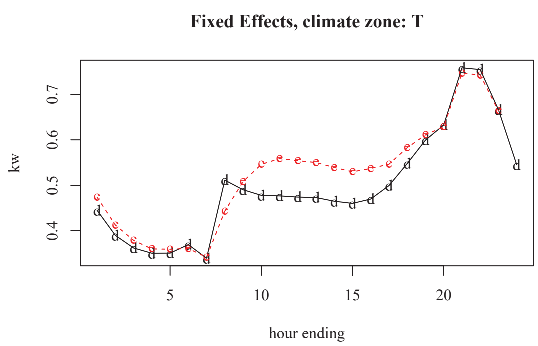

Figure A.24: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band T

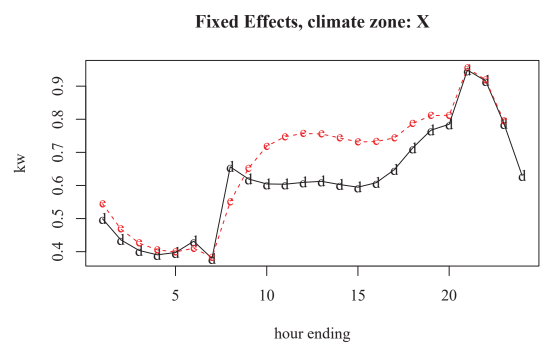

Figure A.25: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band X

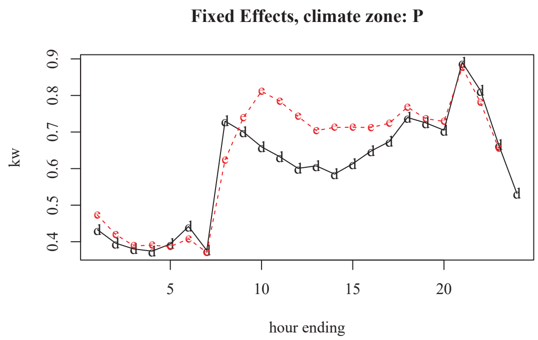

Figure A.26: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band P

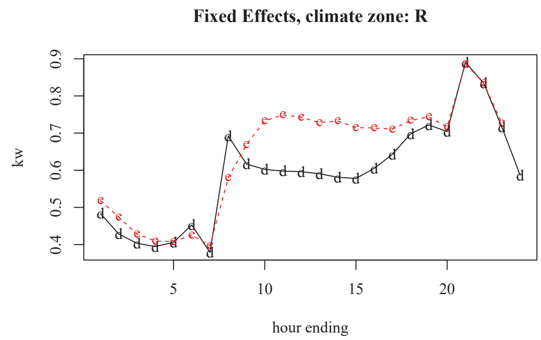

Figure A.27: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band R

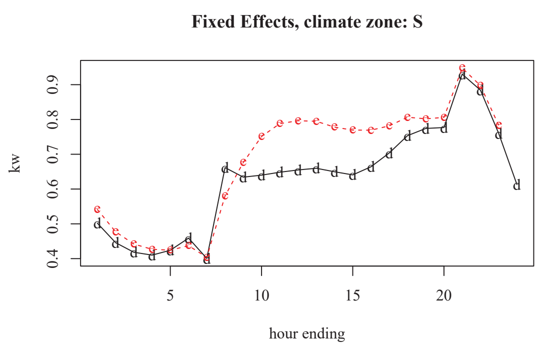

Figure A.28: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band S

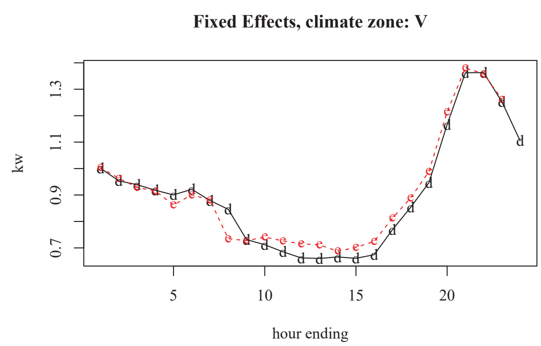

Figure A.29: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band V

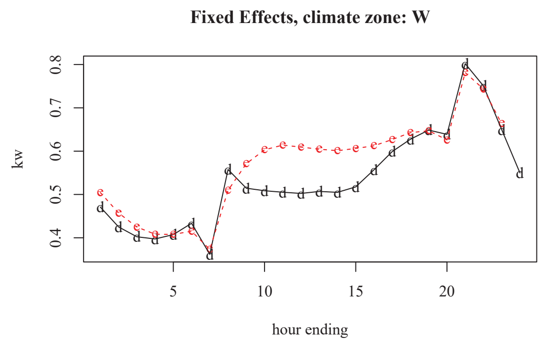

Figure A.30: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band W

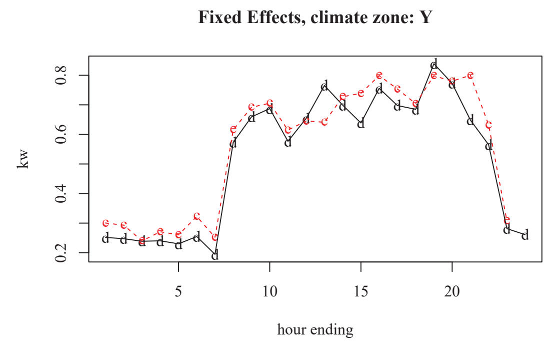

Figure A.31: Estimates of α_{HOD} for weekdays (d) and weekends (e), climate band Y

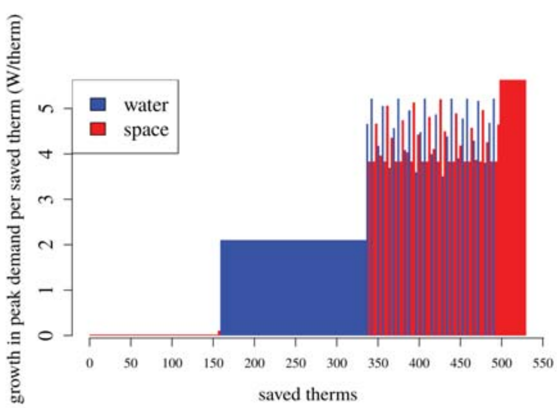

Figure A.32: Supply curve of gas savings, climate band P

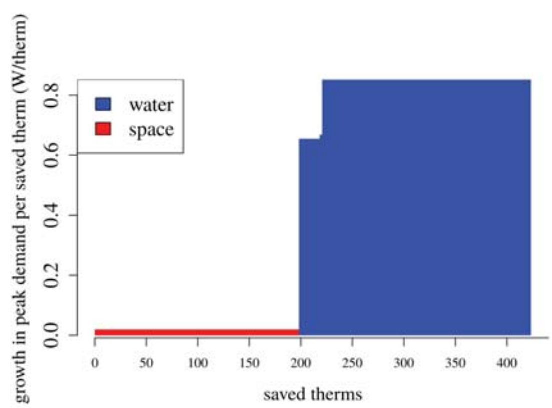

Figure A.33: Supply curve of gas savings, climate band R

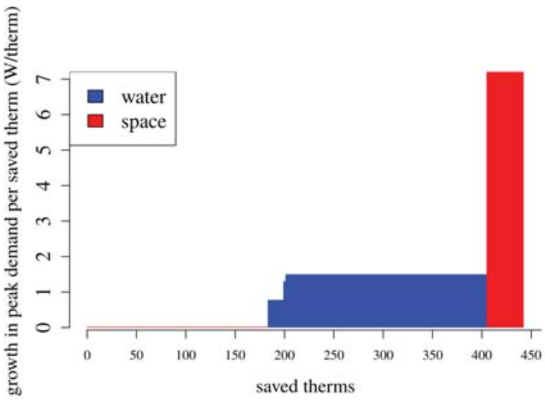

Figure A.34: Supply curve of gas savings, climate band S

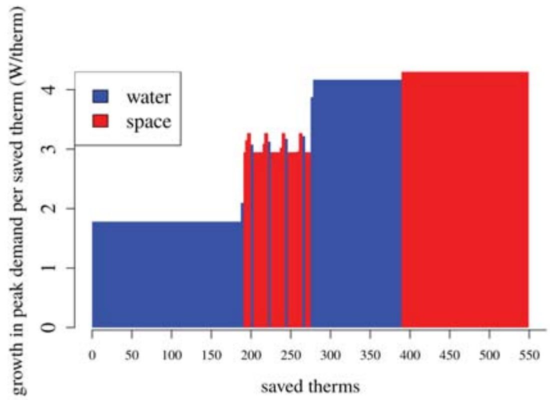

Figure A.35: Supply curve of gas savings, climate band V

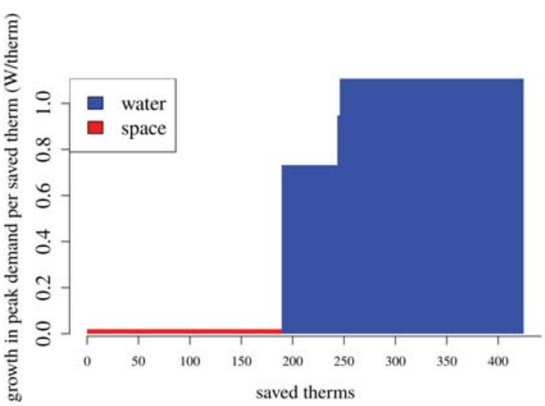

Figure A.36: Supply curve of gas savings, climate band W

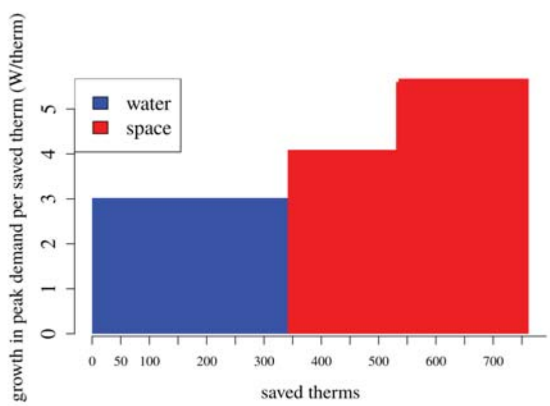

Figure A.37: Supply curve of gas savings, climate band Y