# A dynamic model of building electrification*

Matthias Paustian†
Federal Reserve Board

Vivek Narayan‡
University of Oxford

November 8, 2025

**Abstract**

A number of local governments and state governments in the USA have embraced building electrification and require all-electric equipment in newly constructed buildings. This paper builds a model of the dynamic process by which electrification in newly constructed buildings spreads to electrification in existing buildings. The key channel of spillover is the rising prices of piped gas resulting from a high share of fixed cost in operating a gas distribution system and a slowly declining customer base. The paper takes into account that there are heterogeneous fixed costs in electrifying existing buildings across households. We show that the resulting dynamics depend crucially on how building owners form expectations about the future price of natural gas. We model near rational expectations formation processes based on level-k thinking and show that the rising price of gas can substantially accelerate the rate of decline of gas throughput, aka speed up electrification of the full building stock. We calibrate the model with micro level data from the ResStock and ComStock databases provided by NREL and illustrate the resulting dynamics based on a random sample with detailed building level information in Washington DC.

*First draft February 2023, this draft November 2025. All views are our personal opinions and do not reflect those of the Board or the Federal Reserve System.

†matthias.o.paustian@frb.gov
‡vivek.narayan@economics.ox.ac.uk

# 1 Introduction

Building electrification replaces fossil fuel combustion equipment with electric powered alternatives in residential and commercial buildings. With highly efficient heat pumps for space and water heaters on the market and rapid progress in reducing greenhouse gas emissions in the power sector, building electrification plays an important role in the clean energy transition (Rosenow et al. (2022)). Many local jurisdictions recognize this and require electric equipment in newly constructed and heavily renovated buildings and provide financial incentives for electrification. Nevertheless, building electrification is a slow process in many jurisdictions.

However, a small but steady stream of electrification in one segment of the building stock (for example, early adopters) affects electrification in the rest of the building stock dynamically via the evolution of the price for piped gas. As discussed extensively in Davis and Hausman (2022), the price for piped gas is heavily influenced by the fixed costs of operating a local network of gas main and service pipelines, aka gas distribution costs. These fixed costs need to be borne by a declining customer base resulting from electrification in one segment of the market, typically via increases in the volumetric charge of piped gas. Since the single most important driver of electrification historically is the price of gas in relation to the price of electricity, see Davis (2021), electrification has the potential to spread endogeneously over time and could lead to cascading effects.[1]

[1] There is an existing literature of a similar dynamic playing out where residential solar panels reduce customer electricity consumption and hence distribution and transmission costs for the

This paper presents a dynamic partial equilibrium model for the simulation of electrification scenarios in a region served by a single gas distribution utility. The model consists of three blocks. A regulatory block tracks the rate base of the utility (the assets the utility is allowed to earn a return on), regulatory and actual depreciation and investment. The regulator sets the revenue requirement of the local gas distribution utility. In a second simple block, the gas utility decides how to adjust fixed and volumetric charges for the distribution of natural gas to achieve its authorized revenue requirement. Given these distribution charges, the third block tracks gas equipment replacement and electrification decisions in individual buildings which affect the gas system throughput. Gas throughput then feeds back into the first two blocks over time.

The model takes into account that there are heterogeneous costs of electrifying existing buildings in the cross section. The decisions to electrify existing buildings reflects a trade-off between heat pumps' higher up-front installed costs on the one hand and lifetime operating cost savings in light of rising natural gas prices on the other. The electrification decision then feeds into the evolution of the price of piped gas (the gas distribution cost component) and a dynamic feedback loop entails. Higher gas distribution costs trigger further disconnections, which then raise distribution costs etc.

The electrification scenarios we model are as follows. Our baseline scenario is a path where a small share of existing buildings electrify exogenously every year

electric utility can only be recovered from smaller volumes of sales , see Muaafa et al. (2017) and Laws et al. (2017) and Costello and Hemphill (2014).

and households as well as regulators are myopic. In that baseline, the exogenous disconnections raise the distribution cost of piped gas and trigger additional disconnections - which we call ”endogenous disconnections”. Gas usage eventually goes to zero, but the pace of electrification is slow.

We show that the resulting dynamics depend crucially on how building owners form expectations about the future price of natural gas. We model boundedly rational expectations formation processes based on level-k thinking as recently employed by Farhi and Werning (2019) in a macro-economic context. Level-k thinking models the iterative process by which agents update expectations about endogenous variables (here the price path for gas) starting from a baseline belief of static expectations. With higher levels of belief updates, the collapse of the gas system occurs faster as agents anticipate a rising path of gas and disconnect earlier. In the limit the model converges to rational expectations and agents would like to disconnect as soon as possible.

We calibrate the model with micro level data from the ResStock and ComStock databases provided by NREL and illustrate the resulting dynamics based on a random sample with detailed building level information in Washington DC.[2] Using this empirical model, we show numerically via simulation that rate design by the utility has relatively little influence on the dynamics. Our baseline assumption is that the utility increases volumetric charges in response to the declining number of users. Alternatively, the adjustment might occur via changes in flat customer

[2]We choose Washington DC for its unique status as an identifiable geographic zone in ResStock and ComStock where the service territory of the gas provider matches up one for one with identifiable information in ResStock.

charge. Such an alternative adjustment mechanism does change the composition of users that leave the system at any given point in time (with low volume users having a greater incentive to electrify earlier relative to the baseline assumption), but there is very little change to the overall dynamics of the decline in aggregate gas throughput. The intuition for this finding is that electrification allows the user to completely evade both the flat customer charge and the volumetric gas charge.[3]

This paper extends the related existing literature by modeling both the electrification decision and the determination of the distribution cost component of the price of natural gas jointly. A number of studies have focused on the economics of building electrification, taking the price of delivered fuel as exogenous, see Deetjen et al. (2021) for example. Instead, this paper models the evolution of the price of piped (delivered) natural gas within a local gas distribution utility franchise area as an endogenous outcome that is crucially affected by the electrification decision. In related work, Davis and Hausman (2022) empirically study how a declining customer base affects the price of natural gas in the presence of fixed costs of providing gas distribution services. Importantly, Davis and Hausman (2022) reports that on average about 40 percent of the revenue from the sale of piped gas covers utility fixed costs. When an individual customer stops using gas, the resulting revenue loss towards fixed costs is being recovered by the remaining customer base. Davis and Hausman (2022) documents asymmetries in

[3] In the related case of residential solar adoption, raising fixed customer charges is typically seen as helpful in preventing an electric utility death spirals set in motion by greater residential solar PV adoption. The distinction to the case of gas analyzed here is that these solar PV adopters cannot avoid paying higher customer charges for electricity as completely leaving the electric grid is cost-prohibitive.

utilities' responses to reductions in the customer base. On one hand, utilities increase miles of pipelines when there is an increase in customers. However, there is no corresponding reduction in miles of pipeline when there is a reduction in the customer base. Therefore, the utility's fixed costs remain roughly the same even when it loses customers. In order to achieve its return on investment approved by regulators, the utility is then typically permitted to raise its distribution charge. In contrast to our analysis, Davis and Hausman (2022) do not model the feedback from the rising costs of delivered gas to the electrification decision over time.

## 2 A simple stylized model

A local gas utility serves a unit mass of customers that are identical in all respects, except for the cost of electrification of their residence. We assume that each customer faces a known idiosyncratic excess cost of electrification (measured as the installed cost for electric equipment over and above the cost of installing gas equipment), denoted by $X_i$. There is ample evidence that the cost of electrification differs in the cross section of buildings depending on, for example, the specifics the existing heat distribution systems, the size of the electrical panel etc. In the cross-section, this excess cost has cumulative density denoted by $\Phi(X)$.

$$X_i \sim \Phi(X) \tag{1}$$

We denote the pdf with $\phi$.

**The consumer problem**

Consumers make a choice only at the end of the life of their existing equipment. An individual consumer $i$ choose to replace gas equipment like for like if the lifetime cost of replacing and then operating gas equipment is smaller than the corresponding lifetime cost for the electric alternative.

$$\sum_{j=1}^{D} \beta^j E_t(d^g_{t+j} + f^g_{t+j}) < \sum_{j=1}^{D} \beta^j E_t((d^e_{t+j} + f^e_{t+j}) + X_i \tag{2}$$

Here $\beta$ is the households discount factor and $T$ the lifetime of the equipment. The left hand side is the discounted sum of distribution, $d^g$ and fuel charges, $f^g$, for gas. The first element on the right hand side contains the corresponding distribution, $d^e_t$, and fuel charges $f^e_t$ for the electric alternative. The second element on the right hand side is the excess upfront equipment and installation cost of electrification over and above the cost of installing gas equipment, $X_i$. To simplify notation, we will assume that $\beta = 1$, $f^e_t = f^g_t$. Assuming static expectations (aka agents expect future distribution charges to equal current ones), agent $i$ then chooses electric over gas equipment if

$$X_i < D(d^g_t - d^e) \tag{3}$$

All users whose equipment reaches end of life and whose idiosyncratic electrification costs is lower than a cutoff value $\bar{X}$ given by hte right hand side of this equation will electrify and leave the gas system while all other ones will replace their gas equipment like for like. For simplicity, we assume that the distribution charges for electricity equal the initial gas distribution costs $d^e = d_0^g$, so that the key variable determining the incentive to electrify is simply the change in gas distribution costs over and above their initial level. The share of customers for whom electric equipment is perceived to be cost-effective then is given by

$$\bar{\Phi}_t = \Phi(X_t) \quad \text{with:} \quad X_t = D(d_t^g - d_0^g) \tag{4}$$

Importantly, these excess costs only occurs once during the initial process of fuel switching. Effectively, we assume electrification is an absorbing state. Once a residence has electrified, it is assumed to remain electric powered.

**The problem of the gas distribution utility**

The problem of the gas utility is simple. The utility operates a monopoly franchise and can recover its cost (including any cost of capital) of operating the distribution system via regulatory approved distribution charges. We assume that those costs are sunk and completely fixed over time. In a nutshell it's problem is merely to recover those sunk costs. Our baseline assumptions is that costs are recovered entirely via purely volumetric charges.[4] In particular, we assume that there is a fixed annual revenue requirement of $b$ to recover cost of legacy capital expenditures

[4]In this stylized model, consumers are identical in terms of their volumes of gas usage. Volumetric charges vs. fixed customer charge in a two-part tariff makes no difference here, but it could in the richer empirical model to follow.

for building and maintaining the local gas distribution network. Total volumes of sales at the beginning of the policy scenario are normalized to unity and sales decline in line with the mass of customers over time (aka there is no heterogeneity along the volumes of gas usage across customers). When the mass of residences using gas falls, the volumetric distribution charge $d_t$ rise accordingly to meet this fixed revenue requirement period by period.[5]

$$d_t^g = \frac{b}{S_{t-1}} \quad \text{with:} \quad S_0 = 1 \tag{5}$$

In the baseline model, we assume that $b$ is constant over time and independent of the volume of sales and the number of users. In other words, the utility is not assumed to be able to lower its annual operating costs by strategically abandoning sections of the gas distribution network.

**Policy scenario and dynamic equilibrium**

We consider a scenario where a constant share $p$ of of buildings that use gas electrify permanently in period $t$ for reasons not explicitly modeled in this analysis and disconnect from the gas grid. Such exogenous electrification could happen as as result of a requirement for all electric equipment in the case of major renovations in existing buildings in the local building code, or perhaps because of a preference shift among a small set of environmentally-minded consumers in the population.

[5] Consumers also pay a volumetric charge for the wholesale cost of gas that has no influence on the profits of the distribution utility, as it merely passes on procurement costs without markup to end users

This assumption affects all other users of the gas distribution system only via its impact on the price for gas distribution services. We need to assume some exogenous shock to the parameters affecting customers decisions away from their steady state. The question of interest is then how knock-on effects evolve over time via the feedback mechanism between higher gas distribution charges and future endogenous disconnections.

If there is no source of utility customer growth, the total stock of fossil fuel heated buildings declines over time. The law of motion for the customer base of the gas utility $S_t$ is given by

$$S_t = S_{t-1} - p_{t-1} - a_t. \tag{6}$$

Here, $p_t$ is the mass of exogenously exiting customers following exogenous (passive) electrification. The mass of active exits occurring via endogenous (active) fuel-switching in response to changes in operating costs is denoted by $a_t$.

We assume that heating equipment life is deterministic and equipment lasts exactly $D$ periods (both for electric and gas equipment). Hence, an equipment owner makes an end-of life replacement decision every $D$ years. The age distribution of existing equipment is initially uniform over the ages $1, 2, ..., D$ and this age distribution is independent from the distribution of excess electrification costs. In any given period $t$, additional electrification occurs whenever the cutoff value $\bar{X}_t$ has risen over and above the value prevailing when the owners of that equipment vintage last made decisions about electrification, namely in $t-D$ . The mass of new ”active” electrification in period $t$ is given by the mass of equipment that has reached the end of life , denoted by $m_t$, multiplied by the share of that mass for whom electrification is cost-effective.

$$a_t = m_t \left( \frac{\bar{\Phi}_t - \bar{\Phi}_{t-D}}{1 - \bar{\Phi}_{t-D}} \right) \tag{7}$$

with initial conditions $\bar{\Phi}_{t-D} = 0$ if $t < D$. All owners that do not replace equipment with electric alternative purchase new gas equipment that becomes vintage of the youngest age in the next period.

The dynamic evolution of the system for the endogenous variables $\{S_t, \bar{\Phi}_t, a_t, d_t^g\}$ is given the equations $\{(4), (5), (6), (7)\}$ with an exogenous processes for $p_t$ and the initial conditions as stated in the text.

## 2.1 Calibration and electrification policy scenario

Central to calibration of the model is the value of the utility revenue requirement $b$ *relative* to the excess costs of electrification, $X_i$. This ratio is key for the dynamic feedback loop between customer exists, rising prices for natural gas and endogenous electrification for the following reason.

In our stylized model, we use a density function that is a simple linear transformation of a beta distribution as displayed in Figure 1 . This calibrated distribution function is broadly similar to the one on our empirical model that we micro-found with detailed housing characteristic and equipment cost data.

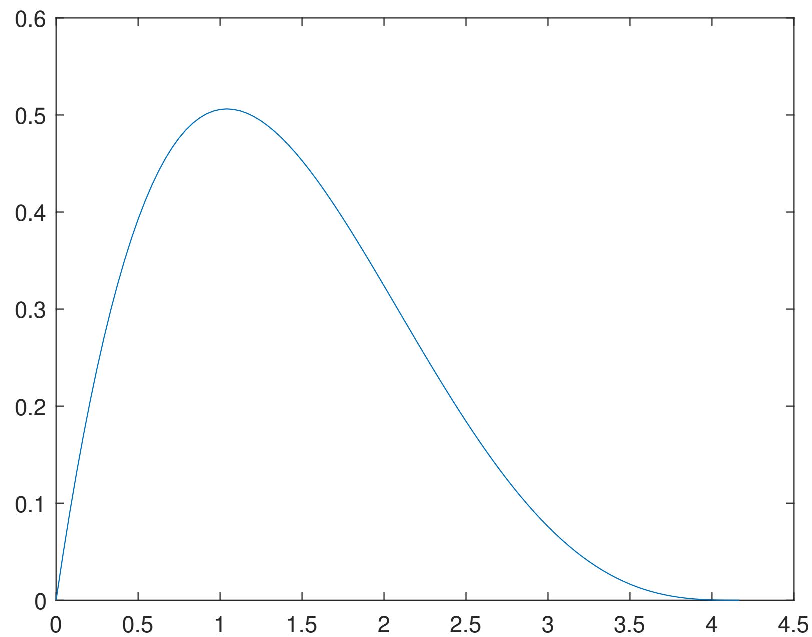



Figure 1: Stylized probability density function of up front costs of electrification relative to lifetime gas distribution expenses, aka plot of the density of $X_i/(Td_0)$.

We calibrate the mode of the density to be unity. Hence, for the modal gas customer the additional cost of electrification is equal to the lifetime charges of gas distribution costs at the beginning of the policy experiment. Therefore, for the modal building distribution charges would need to increase by 100 percent over and above their original value for electrification to be perceived to be cost effective if expectations about the price of gas are static. Thus, our calibration implies substantial excess cost of electrification. Consistent with the empirical evidence, there is a fat right tail in the distribution function as costs could be much higher for a small number of buildings.

**The policy scenario**

One period is assumed to be a year. We model a scenario where 1 percent of all buildings that remain using gas electrify exogenously every year. This could be the result of a policy where electrification is required in all newly constructed buildings and in major renovations as currently being implemented in a number of cities across the nation. We assume that the buildings are drawn randomly, aka they do not modify the distribution function for the cost of electrification of remaining buildings systematically over time. Given this exogenous electrification, natural gas distribution costs evolve over time according to equation (5) and the buildings make their endogenous electrification decision according to equation (4). Figure 2 displays the resulting cumulative masses of gas customers that electrify exogenously (given by the red line) and endogenously (given by the blue line).

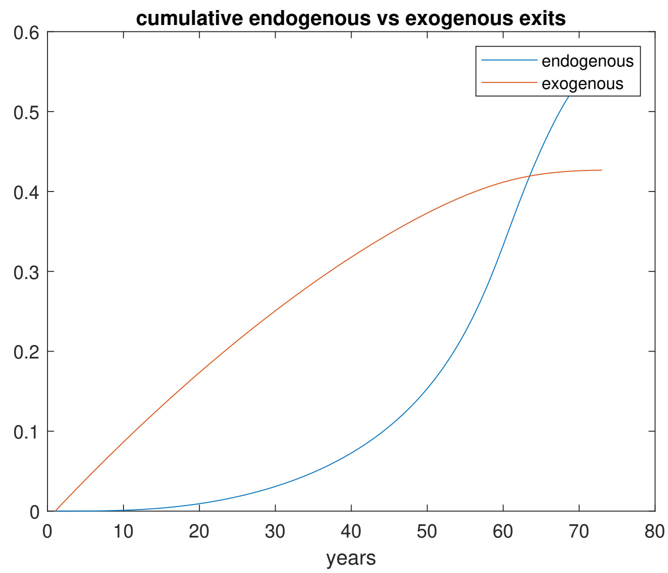



Figure 2: Endogenous vs exogenous electrification

As can be seen in the figure, the dynamics of electrification is entirely dominated by exogenous forces for about the first 20 to 30 years. Electrification is slow initially, because we assume that agents take a decision to electrify only at the end of the useful life of their existing equipment, which we assume to be 15 years. That is, every year, only roughly 7 percent of all customers make an active decision and only a small fraction of those finds it worthwhile to electrify initially. Endogenous electrification then accelerates at a brisk pace for two reasons. First, there is endogenous feedback via the resulting price dynamics. The higher number of exits raises the price of gas further. Second, the distribution of electrification costs is not uniform, in line with our empirical model that we outline later. Instead, the distribution function for electrification costs is initially steep, so that further increase in the price of gas provide incentives for electrification to a greater mass of customers.

Figure 3 shows the resulting evolution of market shares of gas vs electric users, which merely aggregates the endogenous and exogenous shares in the previous figure.

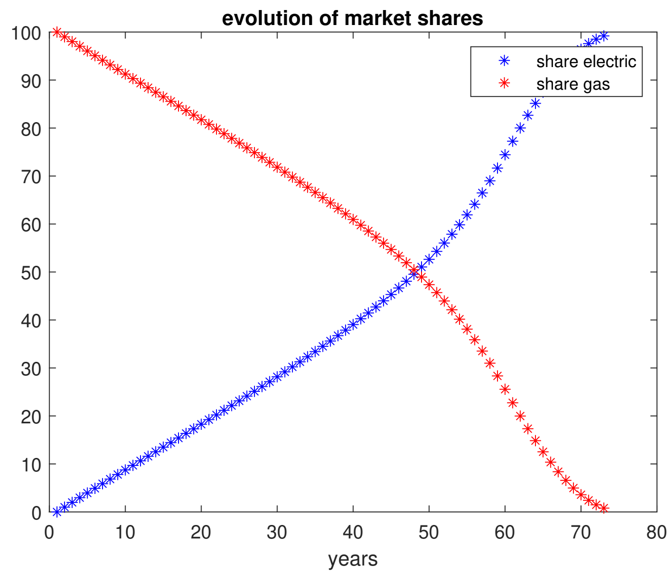



Figure 3: Stylized Model Market Shares

As expected, the resulting dynamics of the market share of gas users evolves non-linearly. It takes roughly 50 years for the gas system to lose half of its original customers base and merely 20 additional years for the customer base to shrink to zero.

**The role of expectations formation: level-k thinking**

The analysis so far has treated expectations formation as static. Customers are assumed to expect future distribution charges to equal current charges. This assumption is consistent with some empirical evidence that household behavior is myopic and results in a conservative estimate of the speed with which electrification proceeds. In this subsection, we explore a form of bounded rationality that allows for imperfect anticipation the evolution of gas distribution charges. In particular, we assume level k-thinking, as recently explored for example by Farhi and Werning (2019). Level-k thinking models expectations formation as an iterative process that occurs in meta time unlike in learning models where agents learn from past observed data. Agents updates beliefs about economically relevant variables beginning from a baseline level of beliefs. We take the baseline level of beliefs to be static expectations, or level-0. Given these level-0 beliefs, agents make decisions and the resulting sequence of outcomes are a temporary equilibrium in the sense of Grandmont (1977). Under level-1 thinking, agents have beliefs about future payoff relevant variables from the temporary equilibrium path for prices that result from level-0 thinking. That path for prices is, of course, increasing over time. Given this now upward sloping price path, agents make decisions about electrification and the resulting outcome is a temporary equilibrium under level-1 thinking. A similar updating process occurs under level-2 thinking and so on. Since the future natural gas price path under level-k thinking is steeper than under level-(k-1) thinking, the incentives to electrify are larger and electrification occurs faster. Figure 4 plots the resulting time path for the market share of gas and electric users over time.

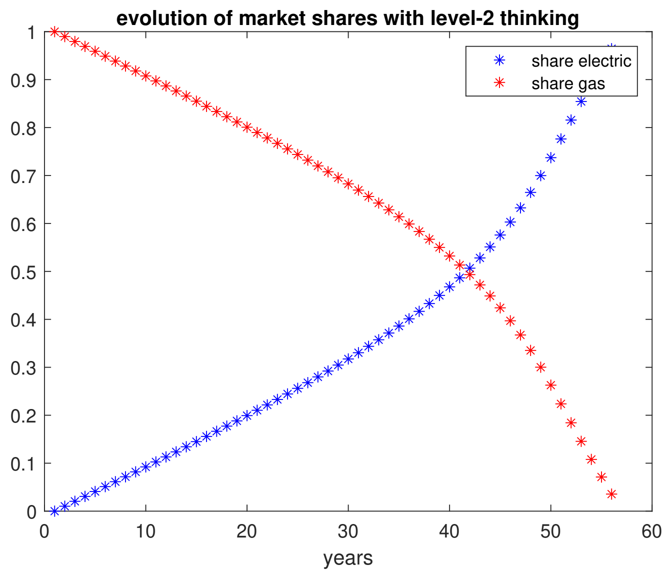



Figure 4: Level 1 thinking

Compared with static expectations under level-0 thinking in the baseline model, full electrification progresses about ten years faster. Updating the beliefs about the distribution charges with the temporary equilibrium under level-1 thinking gives rise to the temporary equilibrium under level-2 thinking, with the corresponding market shares plotted in Figure 5.

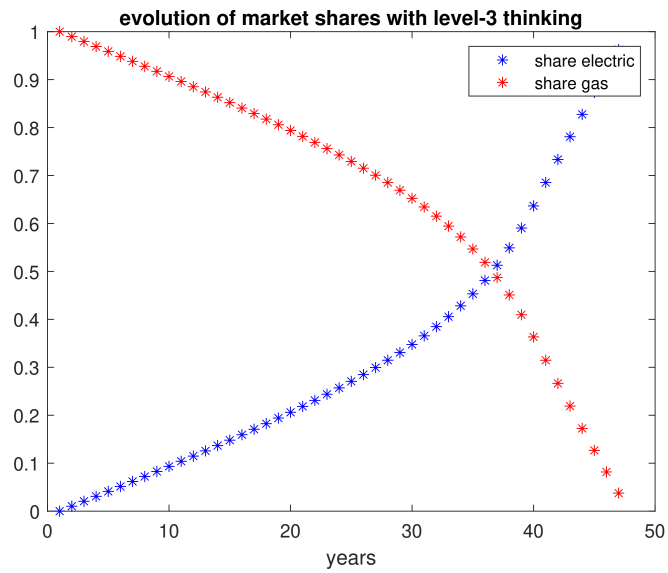



Figure 5: Level 2 thinking

Under level-2 thinking, disconnections from the gas systems proceed at an even faster pace as future price increases are now expected to an even greater extent thereby pulling disconnections forward. Continuing to even higher levels of thinking with $k$ tending to infinity results in a rational expectations where every customer wants to electrify as soon as the exogenous electrification policy is announced. The pure fact that the fossil fuel system has a known end date (with a $1\%$ exogenous electrification rate, the system could last at most 100 years) together with the fact that there are some customer for whom electrification is near cost-parity sets off a cascade of slowly increasing disconnections which trigger price rises, further disconnections, even further price rises and so on. Anticipating this cascade results in a rational expectations equilibrium where every customer would want to disconnect as soon as the policy is announced.

Implicit in this dynamic is the existence of a strategic complementary. Each customer's incentive to disconnect is increasing in the propensity of other customers to disconnect. That complementarity results from the presence of fixed costs in providing distribution services and the ability of the regulated monopoly to raise prices in response to a falling customer base. Of course, in practice there may be offsetting congestion effects in achieving large amounts of electrification in a short period of time, for example due to shortage of a skilled local electrification workforce. Nevertheless, there is a clear possibility for the gas distribution system to be fragile and in principle be subject to potentially self-fulfilling runs on the system.

**Discussion**

A key assumption in this simple model is that the total revenue requirement of the utility covering fixed costs ($b$) is constant over time and independent of the size of the customer base. This is our baseline assumption, because gas utilities have long lived assets and are guaranteed a rate of return on their regulatory assets. A large portion of the revenue requirements reflects sunk investments and the inability to adjust the mileage of pipes in the ground downwards when customers exit, see Davis and Hausman (2022). Furthermore, unless electrification is geographically targeted to certain areas where the distribution system is strategically abandoned, there appears to be little room to reduce expenditures over time as customers exit. At the same time, Hausman (2019) provides evidence that gas utilities appear to have some discretion in the timing of their capital expenditure and that they reduce capital expenditures when wholesale prices of natural gas are high. One possible interpretation is that maintenance can be deferred to some extent and maintenance expenditures are more likely to be deferred when other cost pressure are high. Quantitatively, the results in Hausman (2019) do not appear to be large enough to challenge our assumption that the utility revenue requirement is for all practical purposes constant along a path where the customer base shrinks towards zero. For example, her estimation results imply that even a doubling of the volumetric gas cost would cause the utility to reduce annual capital expenditures per customer by only about \$15, which is about 4 percent of mean annual per customer fixed costs in her sample.[6] Incorporating such small effects into our model would make little difference to the results.

At the same time, there may be reasons to believe that there may be an upper bound on the utility distribution charges in practice for political reasons. This would limit the incentive to disconnect and slow down electrification. We explore this possibility as part of the analysis of an empirically rich model to which we turn next. Our baseline settings assumed that exogenous electrification would eventually affect the entire customer base and hence the ultimate end of the gas utility is also exogenous and only the speed of the loss of customers is endogenous. It is possible that, certain end uses of gas would be prohibitively expensive to difficult and hence would be exempt from the forces of exogenous electrification. For example, combined heat and power (CHP) plants are often very economical to operate and commercial kitchens may be willing to pay a substantial

[6]Note that capital expenditures are only part of the total fixed cost of the utility.

premium for gas usage and are at times exempt from mandated building electrification measures. Here we assume that the total customer base has mass $1 + \theta$, where $\theta$ is the mass of end users who are assumed to remain gas users indefinitely. In this version of the model, the utility revenue requirement per capita continues to be $b$, but the total mass of gas users prior to any electrification is now $(1 + \theta)$. We again assume that this is a constant revenue requirement along the transition path. Let $\mu_t$ denote the payment that each user makes towards upkeep of the fixed costs. The break-even condition for the utility then is

$$\mu_t(S_t + \theta) = b(1 + \theta) \tag{8}$$

Unlike the previous case where $\mu_t$ grows without bound as $S_t$ tends to zero, the fixed costs contribution is now bounded. Essentially, the presence of some users that cannot evade the gas distribution system puts a ceiling on the rise in distribution costs. This ceiling then further slows endogenous exits from the gas system. Assuming that $\theta = 0.25$, we obtain the following dynamic evolution of market shares of the two fuel types (as a share of the market with unit mass for those customers for home electrification possible.)

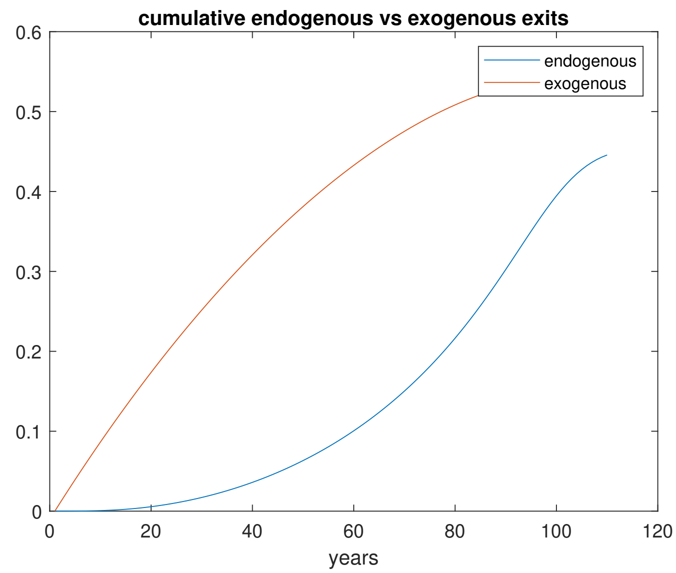



Figure 6: Evolution of exogenous and endogenous electrification an upper bound on price

For simplicity, this figure only plots the evolution of market shares of the two fuels within the group of users that can be electrified. Compared the baseline assumption, the fact that some users cannot electrify slows down the pace of electrification within the group of users that can electrify. In particular, there is now less endogenous electrification and complete electrification of the group of users that can electrify relies more on exogenous electrification.

## 2.2 The role of cost recovery regulation

The regulator allows a revenue requirement $b_t$ that consists of the rate of return $(r)$ on its rate base $(K_t)$, accounting value of depreciation $(D_t)$ and other expenses

$(O_t)$:

$$b_t = rK_t + D_t + O_t \tag{9}$$

The low of motion for rate base is

$$K_t = K_{t-1} - D_t + I_t, \tag{10}$$

where $I_t$ denotes investment.

### 2.2.1 Depreciation scenarios

New investments in gas pipe replacements are typically depreciated over periods that exceed target dates for carbon neutrality in many local jurisdictions, typically the year 2050. For example, regulators in New York State assume depreciation of new gas pipes over a 65 year lifetime, see . Consequently, regulators are studying accelerated depreciation schemes that would limit the size of undepreciated assets in place by 2050. This is particularly important in light of equity concerns for low income households who may not have the resource to electrify early and would be particularly hard hit be rising gas distribution costs should they be among the last to remain users of gas.

Regulators could front loading depreciation, thereby recovering more costs when the customer base in still relatively large. Front loading depreciation would also limit total cost of gas infrastructure, akin to paying off a mortgage early. As a result, the utility's revenue requirement will eventually fall below the revenue requirement from a baseline without early depreciation. Early depreciation therefore creates "fiscal space" that could be used in a number of ways. We study a scenario where the fiscal space is used to provide funding for electrification of low-income households.

That is, we assume that the revenue requirement evolves as

$$b_t = rK_t + D_t + O_t \tag{11}$$

$$O_t = \max(r(\bar{K}_t - K_t), 0) \tag{12}$$

Here, $\bar{K}_t$ is the rate base in a scenario without early depreciation. Under this early depreciation scenario, every period the regulator passes on interest savings from early depreciation, $r(\bar{K}_t - K_t)$ , into an electrification fund. In turn, the electrification fully covers electrification expenditures for low-income households.

We study a scenario where regulators depreciate assets over 25 years. Specifically, we assume a geometric book depreciation schedule at rate $\delta$. Physical investment into the stock of gas distribution infrastructure continues at constant amount equal to a fraction of the initial capital rate base $K_0$ reflecting a need to maintain the physical gas infrastructure even when gas throughput is low.

$$D_t = \delta K_{t-1} \tag{13}$$

$$I_t = \bar{\delta} K_0 \tag{14}$$

Here, we assume that $\bar{\delta} < \delta$ and hence the simulation features accelerated depreciation.

In our simulation, we assume that $\delta = 0.2$ and $\bar{\delta} = 0.1$. In our baseline simulation, rate base was not explicitly tracked, but rather assumed constant. However, we can back out a ”steady-state” rate base from the annual revenue requirement. In particular, taking the revenue requirement $b$ as a primitive, we invert (9)

$$K = \frac{b}{r + \bar{\delta} + \kappa} \tag{15}$$

Here, $\kappa \sim 0$ is the steady-state ratio of operating cost and taxes to the rate base and we calibrate as $r = 0.1$. Under this calibration, the steady state rate base is $5$ times the revenue requirement.

# 3 Empirical model

This section extends the stylized analysis to a richer model calibrated to micro datasets from the National Renewable Energy Laboratory. We use information on building characteristics such as energy usage and heating equipment along with local fuel prices for natural gas and electricity in Washington DC to calculate retrofitting costs for each building. We trace out the dynamic implications of potential electrification policies through the lens of our model.

## 3.1 Data description

We use two datasets provided by the National Renewable Energy Laboratory (NREL).[7] ResStock, the residential dataset, represents single-family homes, multi-family homes, and mobile homes in the contiguous United States. The dataset is based on "conditional probability distributions for each building component [that] were synthesized from data queried, translated, aggregated, and extrapolated from 11 sources, including U.S. census data, the U.S. Energy Information Administration Residential Energy Consumption Survey, builder surveys, and other data from field studies" (Wilson et al. (2017)).[8] ComStock, the commercial dataset, represents the 14 most common commercial building types in the country, which cover roughly 65 percent of commercial floor area. Each observation in ResStock is a dwelling unit, while each observation in ComStock is a building. We use energy use data and various other building characteristics from these databases to construct our own estimates of incremental electrification costs for each building, see Appendix **??** for details.

The most important information in the dataset for our analysis is the annual gas usage for each building. Consequently, we can trace out the loss of revenue to the utility as individual customers exit. Using estimates in Davis and Hausman (2022), we assume that 40 percent of the revenue loss from a customer exit in period $t = 0$ is lost revenue towards covering fixed costs. As in the stylized model,

[7] ResStock and ComStock

[8] It is important to recognize that the database has been validated to be representative for the national housing stock, but less is known about how representative it is at the sub-national level, see Wilson et al. (2022) for model calibration and validation.

we treat this cost as fixed over the entire simulation. At any given point in time, the time-varying number of users of the gas system must pay distribution charges on their bills that add up to this constant value. With this information at hand, we can model the upwards price pressure on remaining gas customers in subsequent periods resulting from the electrification decisions of individual customers.

Table 1 shows the distribution of fuel sources for space heating amongst major building types. Gas is the predominant space heating fuel for single-family residential and commercial buildings, whereas, electricity is the most common space heating fuel in multifamily buildings.

| | Single-Family | Multi-Family | Commercial |
|---|---|---|---|
| Electricity | 20.6 | 56.5 | 32.1 |
| Gas | 78.4 | 39.6 | 67.7 |
| Fuel Oil | 0.9 | 0.9 | 0.0 |
| Propane | 0.2 | 1.0 | 0.1 |

Table 1: Shares of space heating fuel by building type as identified in ResStock and ComStock.

A key issue with ComStock is that it underestimates aggregate gas consumption in Washington DC compared to the Energy Information Administration's (EIA) aggregate estimation of commercial gas consumption in Washington DC. We find that ComStock underestimates aggregate commercial gas consumption relative to the EIA by roughly 80%, whereas, it captures roughly half the floor area[9]. This suggests that ComStock is systematically underestimating gas uWe

[9]We use the Office of Tax Revenue's Computer Assisted Mass Appraisal (CAMA) dataset to find the total square footage in Washington DC.

scale up ComStock's gas consumption by a NREL to BEPS energy use intensity ratio by building type. Details about our scaling up process are in Section C in the appendix. By this method, we are able to better match the share of EIA consumption, given the floor area represented by the sample in ComStock.

| | % of CAMA floor area | % of EIA gas consumption |
|---|---|---|
| RESTOCK | 83% | 83% |
| ComStock | 58% | 51% |

Table 2: Comparison of dataset with external sources after after correcting gas energy use intensities

Table 3 shows that space heating is the dominant end use- accounting for 80.3% of total gas consumption in Washington DC. Water heating accounts for 14.1% of total gas use and the remaining 5.6% of total gas use is used by "interior equipment".[10]

| | Share (%) | Gwh |
|---|---|---|
| space heating commercial buildings | 34.7 | 2201 |
| space heating residential buildings | 45.6 | 2895 |
| of which single-family | 36.9 | 2340 |
| of which multi-family | 8.7 | 555 |
| water heating commercial | 5.4 | 342 |
| water heating residential | 8.7 | 557 |
| of which single-family | 5.0 | 320 |
| of which multi-family | 3.7 | 237 |
| Interior Equipment Commercial | 5.6 | 354 |

Table 3: Annual total gas consumption and shares by end use and building type in ResStock and ComStock, GWh stands for Gigawatt hours.

[10]In ComStock, the interior equipment category refers to any gas usage aside from space and water heating. Examples are pool heating, drying, cooking, fireplaces, etc.

## 3.2 Modeling assumptions

For simplicity, we abstract from general price inflation in our dynamic model. We assume a gas price of \$1.48 per therm at the beginning of the dynamic simulation and a constant electricity price of \$0.165 per kwH based on average 2024 prices [11]. Additionally, we assume a coefficient of performance (COP) of 3.5 for space and water heaters. We assume a minimum 96% efficiency standard for all gas furnaces based on the Department of Energy's (DoE) proposed gas furnace efficiency standards (see Office of Energy Efficiency and Renewable Energy (2022b))[12]. The maximum available efficiency for gas steam boilers is 83.4% (see Office of Energy Efficiency and Renewable Energy (2022c)). We assume that gas steam boilers installed over our model period will reach this efficiency. The assumptions about equipment efficiency are reflected in Table 4.

| equipment | efficiency |
|---|---|
| heat pump water heater | COP: 3.5 |
| heat pump space heater | COP: 3.5 |
| furnace | $\geq 96\%$ |
| hot water boiler | $\geq 96\%$ |
| new steam boiler heating efficiency | $\geq 84\%$ |

Table 4: Assumptions about efficiency

We make the simplifying assumption that the building age distribution is flat

[11] FRED DC Electricity Prices and FRED DC Gas Prices

[12] According to Office of Energy Efficiency and Renewable Energy (2022a), current efficiency standards for gas-fired hot water boilers require 86% efficiency, but the widespread availability of 96.1% efficient hot water gas boilers means that we project that DoE standards will increase to 96%. The term hot water boiler still refers to space heating

and that each building has a lifespan of 100 years before it is either torn down and replaced or heavily renovated. We use 100 years as the building lifespan based on Ianchenko et al. (2020), who find that ”age of highest likelihood of demolition (mode) ranges from 73 to 125 years”. This is a conservative estimate for building ages relative to other residential building lifetime studies such as O’Connor (2004) and Aktas and Bilec (2012) and even more conservative compared to industry estimates for commercial buildings.

We also make the simplifying assumption that heating equipment has a lifetime of 15 years. Agents discount costs over 15 years and make the best decision for that timeframe.

## 3.3 Costs

We use the cost-equations reported in the appendix **??** to construct retrofit installation costs for electric equipment and gas equipment for each piece of heating equipment in our dataset. Each customer faces idiosyncratic incremental electrification costs and operating costs which affect their heating equipment decision. Figure 7 shows the cumulative density of the total costs (installation and lifetime operating costs) of electric heating equipment relative to the corresponding cost of gas in the cross section of all buildings in the dataset. It shows that while there is a subset of customers for whom it is immediately cheaper to electrify, electrification is the more expensive option for most customers even after including heat pump’s lower operating costs. Importantly, this cost comparison holds electricity and gas prices in future periods constant at their initial values. It thus corresponds to calculations that an "uninformed" household might make who forecasts that future gas prices equal current prices.

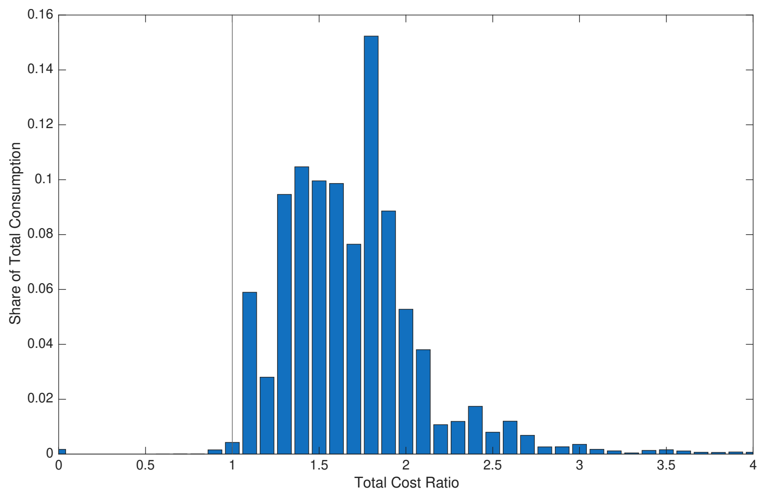



Figure 7: Histogram of the ratio of the present value of lifetime costs of electric equipment relative to gas equipment.

Table 5 shows that the lifetime costs for electric heating equipment are dominated by upfront installation costs in residential buildings. On the other hand, upfront costs are roughly equivalent to operating costs for gas equipment in residential buildings. Commercial buildings are characterized by relatively lower installation to operating cost ratios across the board than residential buildings.

Table 5 shows that lowering the electric to gas operating cost ratio is the only way that Duct installations are a significant component of electric space heating installation costs in larger buildings. Our cost equations imply that duct installation costs represent roughly half of heat pump installation costs for ductless buildings that are larger than 10,000 square feet. Given our fuel cost and equipment efficiency assumptions, operating costs are lower for the electric space and water heat pump equipment than gas counterparts.

| | **Residential** | **Commercial** |
|---|---|---|
| *Installation to Operating Cost Ratio* | | |
| electric water heating | 3.8 | 0.8 |
| electric space heating | 2.6 | 1.2 |
| gas water heating | 1.0 | 0.1 |
| gas space heating | 1.0 | 0.3 |
| *Electric to Gas Installation Cost Ratio* | | |
| water heating | 2.6 | 3.7 |
| space heating | 2.1 | 3.5 |
| *Electric to Gas Operating Cost Ratio* | | |
| water heating | 0.5 | 0.5 |
| space heating | 0.8 | 0.8 |

Table 5: Median of the installation to operating cost ratio, the electric to gas installation cost ratio and the electric to gas operation cost ratio.

## 3.4 How the empirical model departs from the stylized model

The core of the empirical model is similar to the stylized model specified in Section 2. However, instead of normalizing $S_0 = 1$, as the stylized model does, the empirical model uses the NREL dataset to set $S_0$ to the number of gas users in Washington DC and uses building characteristics to calculate idiosyncratic electrification costs with the cost formulas in Section B. In addition to calculating idiosyncratic installation costs, the empirical model also introduces variation in operating costs for electric and gas systems based on equipment efficiency and local electricity and gas prices. This is a departure from the equal operating costs assumption for electric and gas systems in the stylized model. The final aspect of the endogenous decision that is different in the empirical model is that each building owner makes a separate decision for space heating and water heating.

The exogenous electrification mechanisms are similar between the stylized and empirical models. The stylized model assumes that 1% of the remaining gas users electrify exogenously every period. Similarly, the empirical model assumes that buildings that reach the end of their lifespan are heavily renovated and, in turn, electrified in accordance with electrification requirements in the local building code. ResStock and ComStock include building vintage, but they don't track major renovations. Therefore, we make the simplifying assumption that the building age distribution is uniform across the range 0 to 100. The uniform age distribution assumption can be modified to change the rate of exogenous electrification.

Jadun et al. (2017) project residential air-source heat pumps' efficiencies will improve by approximately 65 percent to a COP of over 4 by 2035 under the study's "Moderate Advancement" scenario and by over 85 percent to a COP of about 4.5 under a more advanced technology scenario. Based on this, we find it plausible that available heat pump's efficiency improves 1% each year. We do not assume any improvements in gas efficiency beyond the one-time efficiency improvements described in our modeling assumptions in Section 3.2.

**Algorithm 1:** Simulation Pseudocode

Import $c_i$, equipment efficiencies, and building characteristics from NREL

Reshape data to one row per equipment unit

Compute installation costs

Compute operating costs for gas and electric equipment under current prices

Set utility fixed cost[1] $fc = 0.4 \times tc_0$

**while** *simulation proceeds over years* **do**

  Increment time $t$

  Electrify units reaching end-of-life (passive electrification): $s_t^p$

  **for** *each equipment unit* **do**

    Let $ry$ be remaining equipment lifetime

    Construct cost stream $\mathbf{e}$ (electric retrofit) over years $0, \ldots, ry$

    Construct cost stream $\mathbf{g}$ (gas replacement) over years $0, \ldots, ry$

    Evaluate both cost streams under current fuel prices and operating cost assumptions

    Select the lower-cost option between $\mathbf{e}$ and $\mathbf{g}$

    **if** *the optimal switch occurs in year 1* **then**

      Add unit to $\mathbf{upgrades_e}$ or $\mathbf{upgrades_g}$ depending on technology

  $S_t = S_{t-1} - \mathbf{upgrades_e} - s_t^p$

  Compute total consumption: $C_t = \sum_i^{S_t} c_i$

  Compute distribution charge: $dc_t = \frac{fc}{C_t}$

  Compute delivered price: $p_t = wg + dc_t$

[1] 40% parameter from Davis and Hausman (2022)

## 3.5 Consumer's problem in the flat charge scenario

When jointly evaluating the electrification decision for space and water heating in their building, an agent has 4 options- electrify both, electrify only the space heater, electrify only the water heater, and electrify neither. Since agents can electrify or upgrade their gas technology $m$ before the expiration of the existing gas technology (for the loss of a continuation value- $CV_m$), they have to make the additional decision of when to switch to electric or update their gas heating equipment. For example, there may be a scenario in which it is cheaper to electrify today than remain on gas, but it would be even cheaper to wait 2 years to electrify as the continuation value decreases. There are several other similar scenarios that emerge that require the agent to carefully consider the optimal electrification plans for all their options. The agent solves four distinct minimization problems for each action plan scenario to solve the best timeline for each. The choice variables $e_m, g_m$ represent the number of years after which they either electrify or retrofit gas technology. The subscript $m$ either equals $s$ or $w$ for space and water heating, respectively.

**Electrify water heater and space heater:**

$$
\begin{aligned}
\min_{e_w, e_s} CV_w + \beta^{e_w}[HPI_w] + \sum_{t=0}^{e_w} \beta^t GOC_w + \sum_{t=e_w+1}^{15} \beta^t HPOC_w \\
+ CV_s + \beta^{e_s}[HPI_{e_s}] + \sum_{t=0}^{e_s} \beta^t GOC_s + \sum_{t=e_s+1}^{15} \beta^t HPOC_s \\
+ \max(e_w, e_s) \times FC \qquad (16)
\end{aligned}
$$

**Electrify water heater, remain on gas space heating:**

$$\begin{aligned}\min_{e_w, g_s} & CV_w + \beta^{e_w}[HPI_w] + \sum_{t=0}^{e_w} \beta^t GOC_w + \sum_{t=e_w+1}^{15} \beta^t HPOC_w \\ & + CV_s + \beta^s[GI_s] + \sum_{t=0}^{g_s} \beta^t GOC_s + \sum_{t=g_s+1}^{15} \beta^t GOC_s \\ & + 15 \times FC \end{aligned} \tag{17}$$

**Electrify space heater, remain on gas water heating:**

$$\begin{aligned}\min_{g_w, e_s} & CV_s + \beta^{e_s}[HPI_s] + \sum_{t=0}^{e_s} \beta^t GOC_s + \sum_{t=e_s+1}^{15} \beta^t HPOC_s \\ & + CV_w + \beta^{g_w}[GI_w] + \sum_{t=0}^{g_w} \beta^t GOC_w + \sum_{t=g_w+1}^{15} \beta^t GOC_w \\ & + 15 \times FC \end{aligned} \tag{18}$$

**Remain on gas water heating and space heating**

$$\begin{aligned}\min_{g_w, g_s} & CV_w + \beta^{g_w}[HPI_w] + \sum_{t=0}^{g_w} \beta^t GOC_w + \sum_{t=g_w+1}^{15} \beta^t HPOC_w \\ & + CV_s + \beta^{g_s}[HPI_s] + \sum_{t=0}^{g_s} \beta^t GOC_s + \sum_{t=g_s+1}^{15} \beta^t HPOC_s \\ & + 15 \times FC \end{aligned} \tag{19}$$

All four of these equations are subject to the following constraints:

$$0 \leq e_m, g_m \leq ry^m \tag{20}$$

$$e_m, g_m \in \mathbb{Z} \tag{21}$$

$$CV_m = \beta^{e_m, g_m}[\frac{(ry^m - e_m, g_m)}{15} GI_m] \tag{22}$$

We take the minimum of the four minimized values of the objective functions from equations 16 to 19 to find the optimal electrification plan for the agent. Optimal solutions $e^*_m = 0$ or $g^*_m = 0$ require retrofitting in the current period. Any other solution means that the agent remains on the current technology for the current period.

This problem simplifies greatly for agents with either only gas space heating or only gas water heating or . The agent chooses between the cheapest electrification plan and the cheapest gas retrofit plan for technology $m$ resulting from equations 23 and 24. Again, either $e^*_m = 0$ or $g^*_m = 0$ requires the agent to retrofit either electric or gas technology, respectively, in the current period.

$$\min_{e_m} CV_m + \beta^{e_m}[HPI_m] + \sum_{t=0}^{e_m} \beta^t GOC_m + \sum_{t=e_m+1}^{15} \beta^t HPOC_m + e_m \times FC \tag{23}$$

$$\min_{g_m} CV_m + \beta^{g_m}[GI_m] + \sum_{t=0}^{g_m} \beta^t GOC_m + \sum_{t=g_m+1}^{15} \beta^t GOC_m + 15 \times FC \quad (24)$$

## 3.6 Results

As established in Section 3.3, electrification is the more expensive option for most households and businesses given current prices. However, at any given time, electrification is the cheaper option for a subset of customers (size of this subset is increasing in gas prices and, in turn, time). Additionally, buildings that age out and need to be rebuilt/heavily renovated are required to electrify by policy mandate. These departures from the gas system drive up per user distribution costs. The increased distribution charge burden on the remaining customers pushes more buildings to electrify, which raises the price further, creating a feedback loop. The evolution of the price for the first 40 years of the model can be observed in Figure 8. The gas price increases at an accelerating rate, taking 33 years to rise by 50% but just another 6 years to rise by 100%.

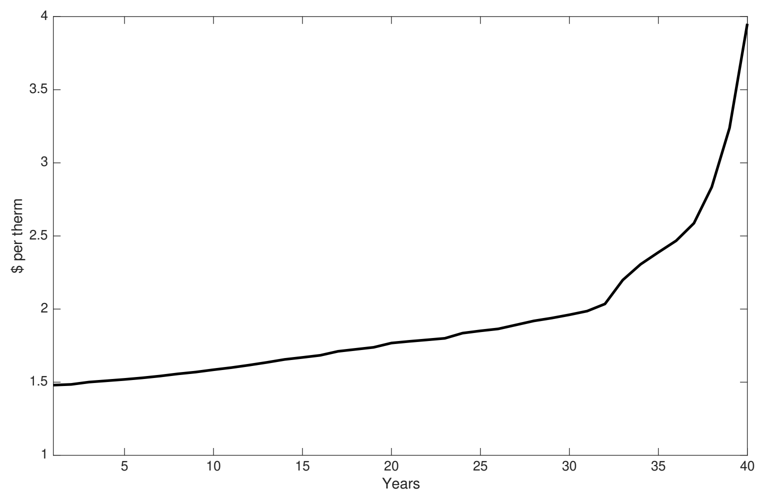



Figure 8: Evolution of the price of delivered gas (assuming a constant fuel cost component)

To isolate the role of the rising gas distribution costs over time (which we call the price mechanism), we consider a scenario where passive electrification occurs but the price of delivered gas is fixed over time (results in Figure 9). In the fixed price scenario, only the buildings that are to the left of the x=1 line in Figure **??** actively electrify. Intuitively, the fixed price and endogenous price scenarios are extremely similar in the initial years of the simulation. However, as observed in Figure 11, active electrification picks up later on in the endogenous price scenario and creates separation between the two models. Since the fixed price scenario relies entirely on passive electrification to electrify buildings other than the small share that are described above, the gas equipment electrifies linearly at a rate of roughly 1% per year for 100 years since we assume a flat age distribution and a lifespan of 100 years.

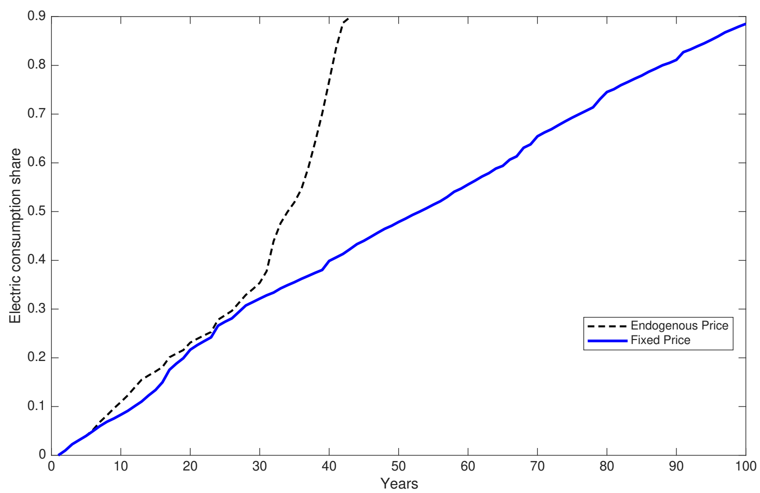
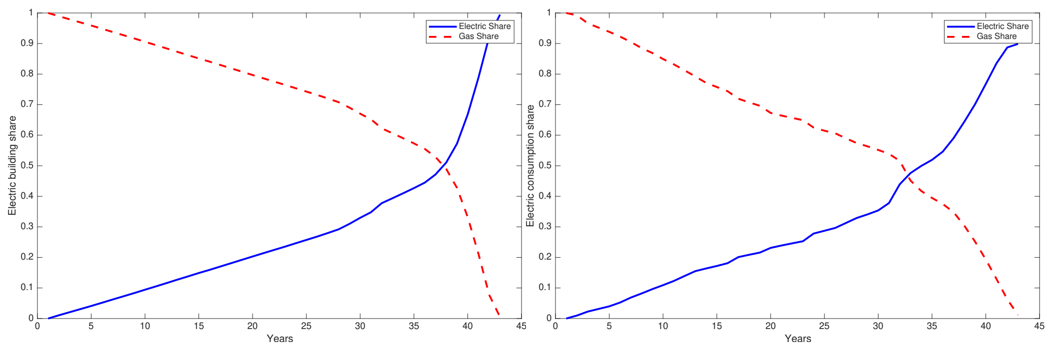



Figure 9: Electric consumption share with fixed and endogenous prices

Figure 10 shows the evolution of the market shares of electric and gas equipment by weighted by heating units and, alternatively, by consumption. 50% of gas consumption electrifies in 34 years in the baseline model. In results shown in Section A, we observe that commercial water heaters electrify the earliest. This is explained by commercial water heating's relatively low installation to operating cost ratios and water heating's low operating costs relative to gas due to gas water heaters' low efficiency (typically $< 70\%$). The combination of high share of operating costs and relatively cheap operating costs for water heat pumps compared to their gas counterparts make them prime candidates for early active electrification. Overall, figures 21 and 20 show that commercial buildings electrify at a relatively constant rate, whereas residential buildings electrify later on in the simulation. This occurs because residential buildings face greater installation to operating cost ratios than commercial buildings (refer to Table 5). Gas prices need to increase more for residential buildings than for commercial buildings to offset electric heating equipment's higher upfront costs[13].




(a) Unit weighted electrification (b) Consumption weighted electrification

Figure 10: Electrification in the baseline model

Since passive electrification applies to 1% of remaining gas buildings by assumption, it slows down over time. Active electrification takes over due to gas-powered heating's increased operating costs and the system continues to move at a steady rate. The distribution of electrification costs and efficiencies means that the empirical model behaves differently to the stylized model. The small number of remaining buildings and their extremely high electrification costs mean that electrifying the last 10% of consumption takes 19 years despite gas prices already being nearly four times as high as period $t = 0$.

[13]Figure 10b does not add up to 100% because some of the initially present gas consumption is made up due to efficiency gains within the gas sector as new gas equipment is assumed to be have greater efficiency than the old one it replaces . As a result, electrifying after updating gas equipment does not result in the full 100% of original consumption getting electrified even though 100% of units get electrified.

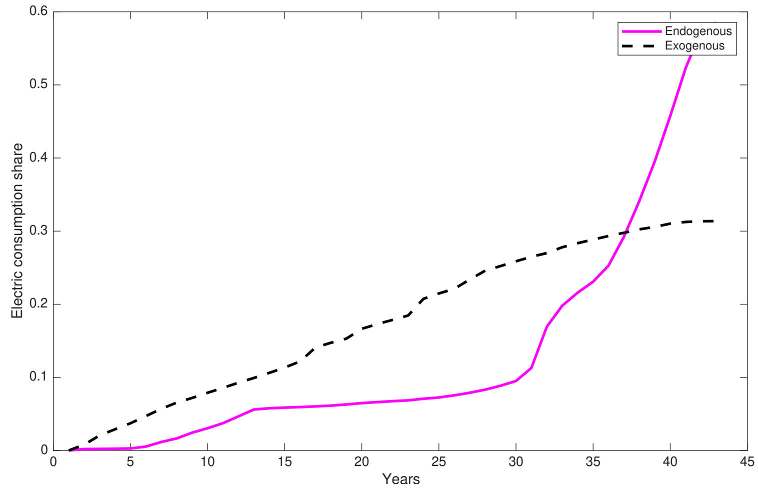



Figure 11: Endogenous and Exogenous Electrification

# 4 Sensitivity analysis

The policy scenario makes a number of baseline assumptions. In this subsection, we show how sensitive our results are to the following alternative assumption. First, we discuss whether a different design of the utility's rate structure affects our results. Second, we examine the implications of assuming that there are some end uses of fossil gas that cannot (or only at prohibitively high price) be powered with electric equipment. Finally, we consider the consequences of the electrification subsidies present in the Inflation Reduction Act for the dynamics of building electrification.

| **Scenario** | **25%** | **50%** | **75%** |
|---|---|---|---|
| Baseline | 23 | 34 | 40 |
| Level-1 | 19 | 23 | 27 |
| Flat Charge | 20 | 33 | 44 |
| Buffer | 24 | 38 | 47 |
| Depreciation | 24 | 53 | 66 |
| Carbon Tax | 22 | 32 | 37 |

Table 6: Years to Electrify for Various Scenarios

Percentages refer to shares of original gas consumption.

## 4.1 Relevance of gas rate design

Thus far, we assume that the utility adjusts its distribution rates in response to lost revenue needed to cover fixed costs by raising individual charges proportionately to the volume of gas consumption. In other words, we assume that utility revenue comes exclusively from a volumetric distribution charge. However, utilities in practice operate with two part tariff (that differs by customer class): a volumetric charge (typically well above the marginal cost of procuring fuel) and a flat "customer charge". Since customer charges are regressive, full recovery of fixed costs through flat charges is not observed in practice.

Costello and Hemphill (2014) show that utilities can avoid revenue losses by increasing customer charges and leaving volumetric charges largely unchanged in the context of electric utilities facing a loss of sales from the adoption of distributed energy generation (residential solar). Residential consumers would have an increased incentive to install solar PV and consume less from the grid when volumetric charges are higher [14] However, the importance of the type of cost recovery is less obvious for this analysis. Importantly, by fully electrifying all gas equipment, customers can avoid fixed and volumetric customer charges altogether, rendering the composition of costs somewhat moot.[15]

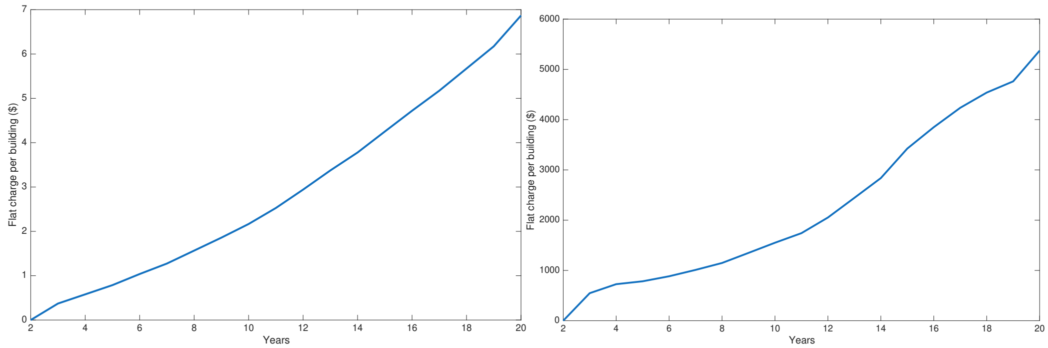
We model two types of customer charges- commercial and residential - that are denoted by subscript $k$. The commercial customer charge covers the lost distribution charge from commercial buildings that electrified in period $t$ ($DC^E_{t,c} = \sum_{i=0}^{E} dc_{i,t}$ where $E$ is the set of buildings that electrify in period $t$) on a per capita basis among commercial buildings. The residential customer charge does the same but for residential buildings. The volumetric share of the charge is denoted by $v$. Suppose that $\eta_{i,t} = \frac{c_i}{C_t}$. The change in the operating cost for building $i$ of type $k$ is shown by equation 25.

$$\Delta oc_{i,t,k} = v \times DC^E_t \times \eta_{i,t} + (1 - v) \times \frac{DC^E_{t,k}}{S_{t,k}} \tag{25}$$

Introducing a customer charge increases the burden of covering the gas rate design to smaller consumers relative to the volumetric rate design we model earlier. As a result, smaller customers electrify earlier. As the customer base dwindles and $S_{t,k}$ gets smaller, the customer charge component, the second term in equation 25, increases in $t$. The flat charge for the lifetime of the equipment is shown in Figure 12.

[14] As a complicating aside, it is not fully clear empirically whether customers respond to average or marginal prices, see Ito (2014).

[15] The same is typically not true for solar PV, because disconnecting from the electric grid entirely is often prohibitively expensive.

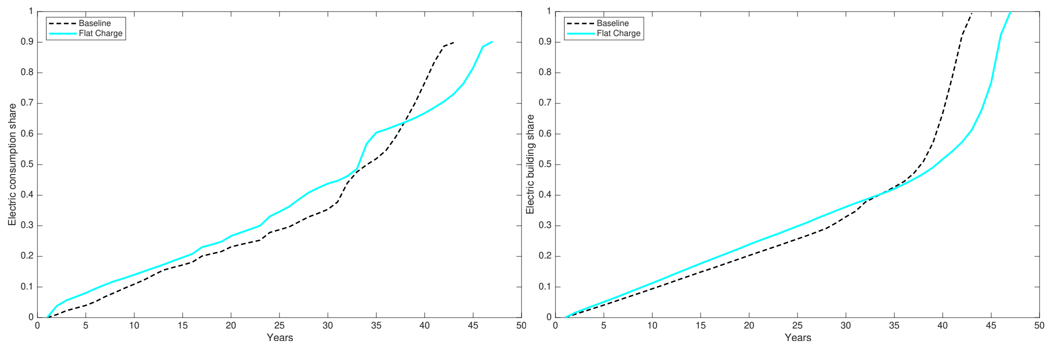



(a) Residential

(b) Commercial

Figure 12: Customer Charges by Building Type

We model a scenario in which $v = 0.5$. This rate structure slows down the rate of electrification. The slowdown is particularly acute for residential buildings. Recall that in the baseline scenario, the commercial sector raised prices which led to active electrification in residential buildings. Since the flat charges contains 50% of the distribution charge within the same customer class, the knock on effect of electrification in the commercial sector upon the residential sector is reduced. As a result, the second 50% of buildings electrify 6 years slower despite the first 50% electrifying 1 year faster. These dynamics can be observed clearly in Figure 13b.




(a) Consumption share (b) Building share

Figure 13: Flat charge scenario vs baseline scenario

An important aspect of the flat charge is that it shifts the distribution charge burden away from larger consumers towards smaller consumers. From the utility's perspective, this would be an effective strategy to stifle customer exits if electrification was relatively more expensive for smaller customers. However, the relative cost of electric space heating to gas space heating is negatively correlated with gas consumption for commercial (-0.10) and residential (-0.22) buildings alike. The relative cost of electric water heating to gas water heating is also negative correlated with gas consumption for commercial (-0.13) and residential buildings (-0.59). This partly counters the aforementioned effect.

Another feature of the flat charge is that it makes remaining on the gas system particularly expensive for customers that have a single piece of gas heating equipment as compared to those with two pieces of gas heating equipment [16].

[16] Table 14 in the Appendix shows that buildings with gas heating are more likely to have gas drying and cooking. We do not model electrification for drying and cooking, however, any customer that wants to avoid the flat charge would need to electrify all interior equipment in addition to space heating and water heating equipment.

## 4.2 Gas buffer share

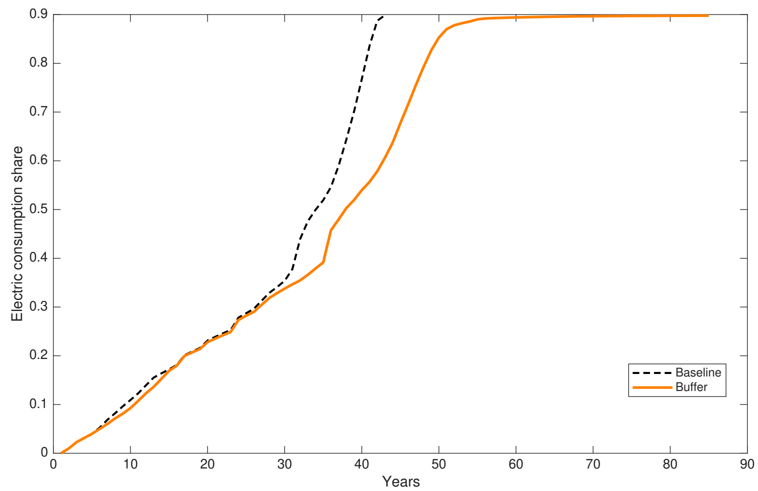



Figure 14: Buffer scenario vs baseline scenario

We introduce a "buffer" as a counterfactual scenario, which is represented in Figure 14. The buffer is a share of gas consumption which cannot be electrified- $\theta$. In this case, we set commercial interior equipment from Table 3 in the appendix as $\theta$. As shown in Figure 14, this share of permanent gas consumption slows down the rate of electrification in every period because $S_{t-1}$ is larger in every period compared to the baseline model. By placing a lower bound $\bar{S}$ on $S_{t-1}$, $d_t$ has an upper bound $\bar{d}$ [17]. As $\theta$ makes up a greater share of $S_{t-1}$, the remaining buildings, $S_{t-1} - \theta$, absorb an increasingly dwindling share of $d_t$. If $\bar{d}$ is not high enough to push gas bills high enough for certain buildings to actively electrify, then those buildings will only passively electrify.

[17] referring to Equation 2

## 4.3 Level-1 thinking

We assume that level-0 thinking refers to the static gas price case described in the baseline model. Level-1 thinkers assume that gas prices grow as they did in the level-0 scenario (i.e. they assume that everybody else is a level-0 thinker). This means that gas prices in the level-0 scenario are strictly greater than level-1 prices for all periods after year 1. As in the stylized model in Section 2.1, expectations about future prices are a key component of each decision. Strictly monotonic prices mean that the dynamics progress faster in higher levels of thinking.

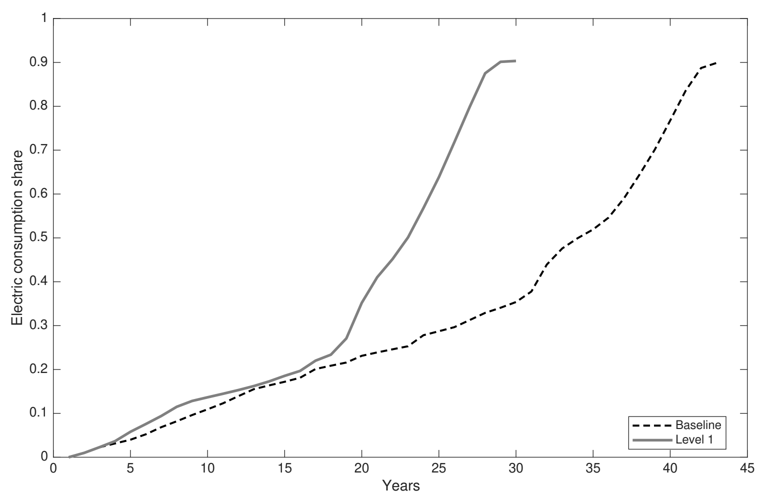



Figure 15: Level-1 thinking scenario vs baseline scenario

## 4.4 Carbon tax

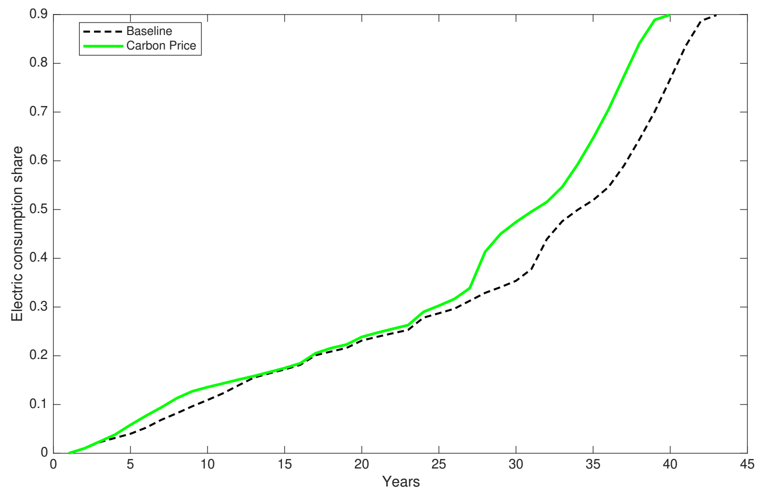



Figure 16: Electric Consumption Share with Carbon Price

We estimate the effect of a \$40 per ton carbon tax. A carbon tax increases heating equipment's operating costs relative to installation costs by increasing gas and electricity prices[18], which favors electric equipment. As per Figure 18, it also makes gas relatively more expensive than electricity since the marginal kwh of gas-powered delivered heat has a higher carbon footprint than the marginal kwh of electricity-powered delivered heat. Our analysis does not account for adaptation in the energy mix to a carbon tax by electricity generators that would likely dampen the effect of a carbon tax on electricity prices. For the aforementioned reasons, a carbon tax's effect on electrification is unambiguously positive. Relative to the baseline,

[18]We abstract from increased manufacturing costs due to a carbon tax.

## 4.5 Depreciation

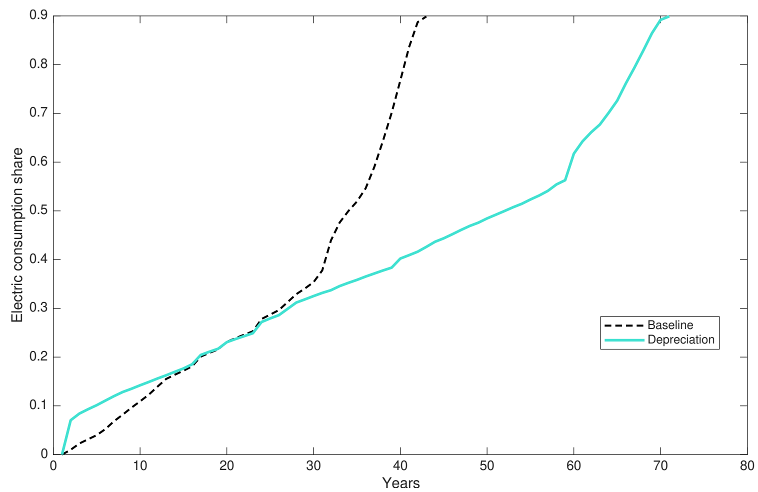



Figure 17: Accelerated depreciation scenario vs baseline scenario

This scenario is discussed in theory in 2.2.1. The baseline model assumes a constant fixed cost recovery over time, whereas, accelerated depreciation pulls the cost recovery forward. The accelerating dynamics in the latter part of the baseline model are arrested in the depreciation scenario because there is less fixed cost for the utility to recover.

# 5 Additional considerations

In this section, we discuss four additional factors that we do not model but impact the speed of electrification. First, we acknowledge the presence of exogenous factors aside from policy mandated switching that can cause switching from gas heating equipment to electric heating equipment. Second, we highlight our model's omission of heat pumps' cooling functions. Third, we note the ambiguous impact that a significant increase in demand would have on electricity prices and in turn customers' electrification decisions. Fourth, landlords may not undertake costly retrofits if it is tenants that pay utility bills.

Although our model assumes a small, policy-mandated reduction in gas customers, there are other exogenous factors that could raise distribution charges per unit of gas and, in turn, gas prices. The five-year aggregate gas consumption for 2019-2024 was 10% lower in Washington DC than the five-year average for 2014-2018. The reduction in consumption can largely be explained by a 8% reduction in heating degree days between these two five year periods. Reduced demand for gas due to warmer temperatures is a potential exogenous factor that reduces gas consumption and makes gas more expensive. Another example is increasing concern about climate change that drives environmentally conscious households and businesses to switch to electric heating equipment. Dwaikat and Ali (2016) find that certain building owners and investors are willing to pay a "green premium" in contexts in which the green option is costlier. An increasing green premium would mean that a greater share of customers are willing to switch to electric heating even if it is uneconomical, thereby prompting the feedback loop we discuss in our paper. Geopolitical events and uncertainties that raise gas prices like the Ukraine War are also exogenous factors that could prompt disconnections. Gas prices rose over three fold from 2021 to 2022 in Germany and were accompanied with a 53 % rise in heat pump sales between the two years. Even if certain gas distribution systems may not be impacted by policy induced disconnections, exogenous disconnections can still occur and have implications for remaining customers.

Our economic analysis of air source heat pumps is restricted to only its heating component, however, air source heat pumps have dual capabilities of heating and cooling. Murphy et al. (2021) deal with this by attributing just half of a heat pump's installation cost towards heating when evaluating electrification decisions (implying that the other half is for cooling). Comparing the heat pump's installation cost to the sum of installation costs for gas heating and an AC unit make the heat pump's economics more favorable. Mahone et al. (2019) find the air conditioning equipment price, \$3500, to be nearly three times as much as the cost of a gas furnace, \$1200, for a 1500 square foot home in San Francisco. Accounting for heat pumps' cooling capabilities is particularly relevant in mixed climates such as Washington DC that require heating and cooling. Byrne and Ghoubali (2019) find that heat pumps cool and heat more efficiently than their fossil fuel counterparts. Lower operating costs and a single fixed cost for all space conditioning would make heat pumps even more economical and would accelerate the dynamics at play.

Large scale building electrification would cause an increase in electricity demand. We do not model the effect of that increase on the transmission and distribution costs for the grid. Up to the point of exceeding peak load, a rising volume of electricity sales has the reverse effect of what we model for the gas utility. As the electricity grid supplies more electricity, the cost of distributing electricity gets cheaper per unit up until the point where new electricity distribution infrastructure investment is needed. Our model assumes a static, exogenous cost of electricity, but if the same feedback loop is applied to dynamic electricity prices, then the gas share falls more quickly initially. However, it is unclear what infrastructure investments would need to be made and how they would be financed if the grid had to be built out to handle space and water heating for the entire city. This question is beyond the scope of this paper but is an important one to answer in order to fully build a dynamic model of building electrification.

Our model assumes that the agent paying the upfront installation cost also benefits from future lower operating costs. However, this assumption will not hold perfectly in all scenarios. Therefore, it is important to consider principle-agent market failures for rental properties in form of the landlord-tenant problem. Petrov and Ryan (2021) explain that the ”landlord-tenant problem is characterised as an agency problem which leads to an under-investment in energy efficiency by the landlord”. This problem is mitigated by the fact that energy retrofits’ costs are often recovered through higher rental prices (von Platten et al. (2022)).

# 6 Cost-benefit analysis

The analysis so far has focused on the dynamics of buildings electrification, aka on the determinants of the speed with which electrification proceeds. Our model is also suited to study the costs and benefits of decarbonization building electrification with regards to carbon emissions. We combine our model’s electricity and gas consumption output with projections of marginal emissions in the power sector. Measuring greenhouse gas emissions from electrification requires taking a stand on the marginal emissions in the power sector and importantly their evolution over time. Holland et al. (2022) document that while the US power sector has seen a large decline in average carbon emissions since 2010 nationally, marginal emissions have risen slightly as a result of growing electricity demand. We use the "mid-case" projected marginal emissions rates for electricity for the RFCEc region from Gagnon et al. (2022b).[19] It is important for us to select the RFCEc region because marginal emissions rates have significant spatial heterogeneity, see Zivin et al. (2014) and Holland et al. (2016). As the name suggests, the mid-case provides a reasonable outlook between the more extreme "no-action" and "95% decarbonization" scenarios. We follow NREL and use long-run marginal emissions factors. The concept of long run marginal emissions factor deviates from the short run marginal emissions factor in that it assumes capital investments into renewable generation, capital asset retirement, and other structural modifications to the grid.

We presume that the building electrification policy is restricted to Washington DC, which is not a big enough player to endogenously change regional marginal emissions rates significantly. Gagnon et al. (2022a) only projects marginal emissions rates until 2050, so we use their 95% decarbonization scenario marginal emissions value as our endpoint after 100 years and interpolate with a cubic func-

[19]Gagnon et al. (2022a) explain this concept as follows "*The long-run marginal emission rate (LRMER) is the emission rate of the generation that would either be induced or avoided by a marginal change in electric load, including both the operational and structural (e.g., building new generation or transmission capacity) consequences of the marginal change. This is in contrast to the short-run marginal emission rate, which is the emission rate that would serve a marginal increase in load, but with the capital assets of the grid being fixed (i.e., the short-run marginal emission rate only reflects the immediate operational consequences of a marginal change in load).*"

tion to get figures for the remaining years. Gas has a constant emissions rate of 5.3 kg per therm [20]. Note that Figure 18 plots marginal emissions of delivered heat, which includes annual 1% COP growth. As shown in Figure 18 and in Row 1 of Table 7, there is a significant drop in marginal emissions in the first 15 years, however, the reduction slows down as electricity demand increases.

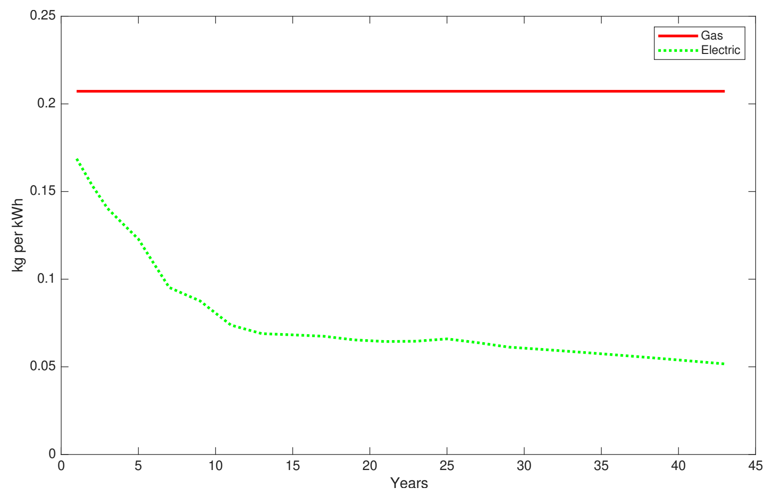



Figure 18: Electric vs Gas Marginal Emissions of Delivered Heat

Figure 19 shows the evolution of total, gas, and electric emissions over time. As follows from our empirical results in Section 3, electric emissions substitute gas emissions over time. The marginal emissions figure 18 and the higher efficiency of heat pumps relative to gas counterparts mean the electric emissions substitute gas emissions at less than a 1:1 rate. We include a leakage factor of 10% in our emissions calculation. It is important to note that there are many

[20]https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

dimensions to assessing benefits from decarbonization. Brockway et al. (2022) place cobenefits from energy demand reduction induced decarbonization into five broad categories "Health, Energy Security, Economy, Social, and Environment". Our model projects nearly a 75% reduction in emissions by 2080 from space and water heating due to falling marginal emissions and increasingly efficient heat pumps (see last row of Table 7).

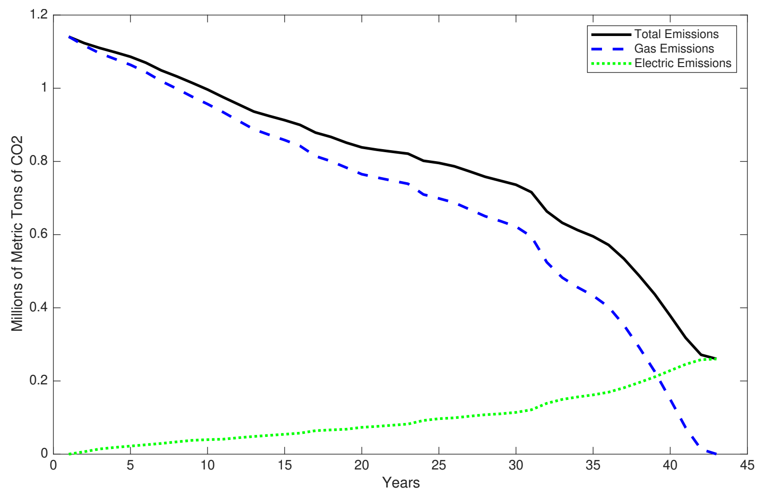



Figure 19: Emissions from Space and Water Heating

We calculate the policy's implied carbon abatement cost for active (endogenous decision made my building owner) and passive (exogenous decision made by policymaker) electrification in Table 7. Two factors determine the implied carbon abatement - the relative cost of a gas system to an electric system and the marginal emissions from the power sector. The implied carbon abatement cost is calculated by subtracting the total lifetime cost of using gas systems from the total lifetime cost of the using electric systems and dividing by lifetime emissions avoided. This gives us an implied cost of carbon in units of $ per CO2 ton. At the beginning of the simulation, passive electrification has a high implied cost, as electrification for random subsets of buildings in Washington DC is relatively expensive at lower gas prices. However, active electrification, by definition, has a negative implied cost of carbon. As gas prices increase and marginal emissions from the power sector fall, the implied cost of carbon for passive and electric electrification reduces and even becomes negative by the end of the simulation for passive electrification.

| **Years** | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 | 2060 | 2065 |
|---|---|---|---|---|---|---|---|---|---|
| **Gas Price** | 1.48 | 1.52 | 1.59 | 1.67 | 1.77 | 1.85 | 1.96 | 2.39 | 3.95 |
| **ME** | 452 | 311 | 277 | 277 | 296 | 286 | 238 | 184 | 131 |
| **MAC: PE** | 502 | 356 | 370 | 249 | 274 | 169 | 77 | -514 | -2899 |
| **TE** | 1.14 | 1.07 | 0.98 | 0.89 | 0.83 | 0.76 | 0.57 | 0.40 | 0.30 |

TE= District wide total emissions from space and water heating (millions of metric tons)
Gas price is in $ per therm

Table 7: emissions analysis

# 7 Conclusion

This paper has studied the dynamic spillover of building electrification policies from one segmented of the market to the stock of existing buildings. The key mechanism for spillover is that disconnections from the gas grid trigger price increases which trigger further disconnections and so on and so forth. At the heart of this mechanism is long lived infrastructure whose costs are largely invariant to the number of users. With guaranteed return on past investments by utility regulators, rates have to rise when the number of users or their gas demand falls. How quickly rising gas prices lead to additional disconnections depends crucially on the distribution of upfront cots of electric vs gas equipment in the cross section of users. We calibrate the model with detailed information on the costs of electrification equipment using data from Washington DC as a case study.

A central finding from our paper is the importance of households' beliefs about how electrification will shape the future price of natural gas. The results assuming bounded rationality along the lines of level-k thinking show that the belief that others gas users will electrify in future will trigger disconnection and hence speed up electrification. Signals from policymakers with regards to future gas consumption and hence future gas prices can play a significant role in expectations formation and, in turn, the rate of disconnections. Exogenous forces aside from policy mandates such as increased climate consciousness can also accelerate the rate of disconnections. In turn, the gas utility can adjust its pricing policy by choosing to change volumetric charges or change flat fees in response to a shrinking customer base. Reacting via customer class-specific flat charges can slow down the rate of disconnections somewhat but ultimately only has a limited impact on the speed of electrification.

The analysis has made a number of simplifying assumptions that should be relaxed in future research. First, we have assumed the annual revenue requirement is literally fixed over time. We could relax this by assuming that targeted disconnections are possible that reduce the fixed costs of the gas system strategically. Second, we have not considered an evolution of the gas monopoly franchise away from selling gas and towards selling zero emissions heating services, for example via networked geothermal systems. These issues would be fruitful avenues for future research.

# References


AKTAS, C., AND M. BILEC (2012): "Impact of lifetime on US residential building LCA results," *International Journal of Lifecycle Assessment*, pp. 337–349. 29

BROCKWAY, A., D. CALLAWAY, AND S. ELMALLAH (2022): "Can Distribution Grid Infrastructure Accommodate Residential Electrification and Electric Vehicle Adoption in Northern California?," Energy Institute Working Paper 327, Energy Institute at Haas. 55

BYRNE, P., AND R. GHOUBALI (2019): "Exergy analysis of heat pumps for simultaneous heating and cooling," *Applied Thermal Engineering*, 149, 414–424. 51

COSTELLO, K., AND R. HEMPHILL (2014): "Electric Utilities' 'Death Spiral': Hyperbole or Reality?," *The Electricity Journal*, 27(10), 7–26. 2, 42

DAVIS, L. (2021): "What Matters for Electrification? Evidence from 70 Years of U.S. Home Heating Choices," Haas Energy Institute Working Paper 309R, University of Berkeley. 1

DAVIS, L., AND C. HAUSMAN (2022): "Who Will Pay for Legacy Utility Costs?," *Journal of the Association of Environmental and Resource Economists*, 9, 1047–1085. 1, 4, 5, 18, 25, 33

DEETJEN, T., L. WALSH, AND P. VAISHNAV (2021): "US residential heat pumps:

the private economic potential and its emissions, health, and grid impacts," *Environmental Research Letters*, 16, 1–17. 4

DWAIKAT, L., AND K. ALI (2016): "Green buildings cost premium: A review of empirical evidence," *Journal of Energy and Buildings*, 110(1), 396–403. 50

FARHI, E., AND I. WERNING (2019): "Monetary Policy, Bounded Rationality, and Incomplete Markets," *American Economic Review*, 109, 3887–3928. 3, 15

GAGNON, P., W. FRAZIER, E. HALE, AND W. COLE (2022a): "Cambium Documentation: Version 2021," Discussion Paper 6A40-81611, National Renewable Energy Laboratory. 53

——— (2022b): "Long-Run Marginal Emission Rates for Electricity- Workbooks for 2021 Cambium Data," Discussion Paper 6A40-81611, National Renewable Energy Laboratory. 53

GRANDMONT, J. M. (1977): "Temporary General Equilibrium Theory," *Econometrica*, 45(3), 535–572. 15

HAUSMAN, C. (2019): "Shock Value: Bill Smoothing and Energy Price Pass-Through," *The Journal of Industrial Economics*, 67 (2), 242–278. 18, 19

HOLLAND, S., M. KOETCHEN, E. MANSUR, AND A. YATES (2022): "Why marginal CO2 emissions are not decreasing for US electricity: Estimates and implications for climate policy," *Proceedings of the National Academy of Sciences of the United States of America*, 119 (8), 1–11. 53

HOLLAND, S., N. MULLER, E. MANSUR, AND A. YATES (2016): "Are There Environmental Benefits from Driving Electric Vehicles? The Importance of Local Factors," *American Economic Review*, 106 (12), 3700–3729. 53

IANCHENKO, A., K. SIMONEN, AND C. BARNES (2020): "Residential Building Lifespan and Community Turnover," *Journal of Architectural Engineering*, 26(3). 29

ITO, K. (2014): "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing," *American Economic Review*, 104(2), 537–563. 43

JADUN, P., C. MCMILLAN, D. STEINBERG, M. MURATORI, L. VIMMERSTEDT, AND T. MAI (2017): "Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050," NREL Technical Paper 6A20-70485, National Renewable Energy Laboratory. 32

LAWS, N., B. EPPS, S. PETERSON, M. LASER, AND G. K. WANJIRU (2017): "On the utility death spiral and the impact of utility rate structures on the adoption of residential solar photovoltaics and energy storage," *Applied Energy*, 185, 627–641. 2

MAHONE, A., L. CHARLES, Z. SUBIN, M. SONTAG, G. MANTEGNA, A. KAROLIDES, A. GERMAN, AND P. MORRIS (2019): "Residential Building Electrification in California," Discussion paper, Energy & Environmental Economics. 51

MUAAFA, M., I. ADJALI, P. BEAN, R. FUENTES, S. KIMBROUGH, AND F. MURPHY (2017): "Can adoption of rooftop solar panels trigger a utility death spiral? A tale of two U.S. cities," *Energy Research and Social Science*, 34, 154–162. 2

MURPHY, C., T. MAI, Y. SUN, P. JADUN, M. MURATORI, B. NELSON, AND R. JONES (2021): "Electrification Futures Study: Scenarios of Power System Evolution and Infrastructure Development for the United States," Technical Report TP-6A20-72330, National Renewable Energy Laboratory. 51

O'CONNOR, J. (2004): "Survey on actual service lives for North American buildings," . 29

OFFICE OF ENERGY EFFICIENCY AND RENEWABLE ENERGY (2022a): "Energy Conservation Program: Energy Conservation Standards for Consumer Boilers," . 28

——— (2022b): "Energy Conservation Program: Energy Conservation Standards for Consumer Furnaces," . 28

——— (2022c): "Energy Conservation Program: Energy Conservation Standards for Consumer Products; Early Assessment Review; Boilers," . 28

PETROV, I., AND L. RYAN (2021): "The landlord-tenant problem and energy efficiency in the residential rental market," *Energy Policy*, 157. 52

ROSENOW, J., D. GIBB, T. NOWAK, AND R. LOWES (2022): "Heating up the global heat pump market," *Nature Energy*. 1

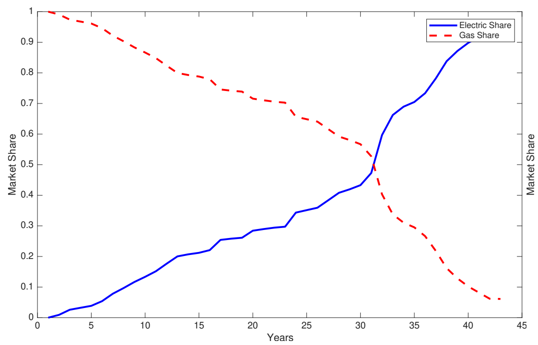
von Platten, J., M. Mangold, T. Johansson, and K. Mjörnell (2022): "Energy efficiency at what cost? Unjust burden-sharing of rent increases in extensive energy retrofitting projects in Sweden," *Energy Research and Social Science*, 92. 52

Wilson, E., C. Christensen, S. Horowitz, J. Robertson, and J. Maguire (2017): "Energy Efficiency Potential in the U.S. Single-Family Housing Stock," Technical Report TP-5500-68670, National Renewable Energy Laboratory. 25

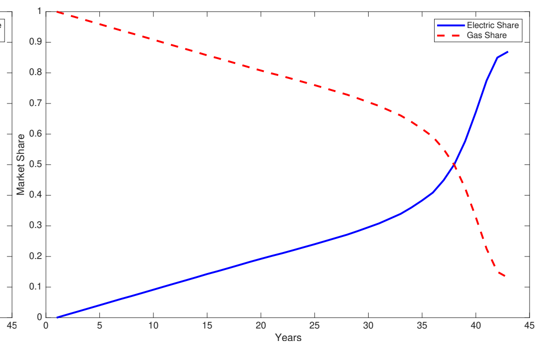
Wilson, E., A. Parker, A. Fontanini, E. Present, J. L. Reyna, R. Adhikari, C. Bianchi, C. CaraDonna, M. Dahlhausen, J. Kim, A. LeBar, L. Liu, M. Praprost, L. Zhang, P. DeWitt, N. Merket, A. Speake, T. Hong, H. Li, N. M. Frick, Z. Wang, A. Blair, H. Horsey, D. Roberts, K. Trenbath, O. Adekanye, E. Bonnema, R. E. Kontar, J. Gonzalez, S. Horowitz, D. Jones, R. T. Muehleisen, S. Platthotam, M. Reynolds, J. Robertson, K. Sayers, and Q. Li (2022): "End-Use Load Profiles for the U.S. Building Stock: Methodology and Results of Model Calibration, Validation, and Uncertainty Quantification," Technical report, US Department of Energy. 25, 70

Zivin, J., M. Kotchen, and E. Mansur (2014): "Spatial and temporal heterogeneity of marginal emissions: Implications for electric cars and other electricity-shifting policies," *Journal of Economic Behavior and Organization*, 107, 248–268. 53

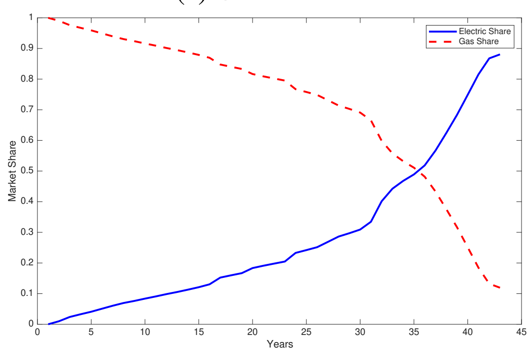
# A Additional Figures



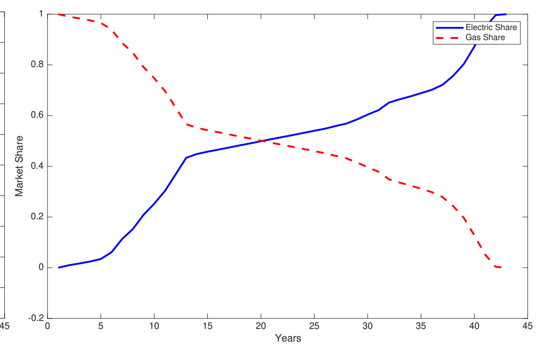

(a) Commercial




(b) Residential

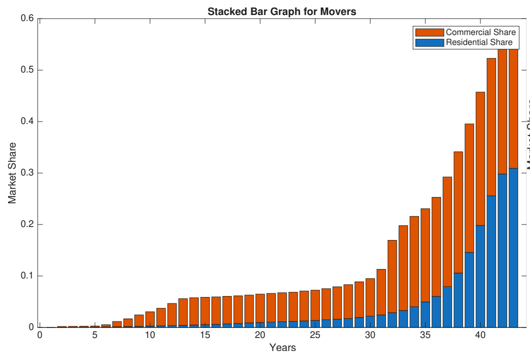



(c) Space Heating

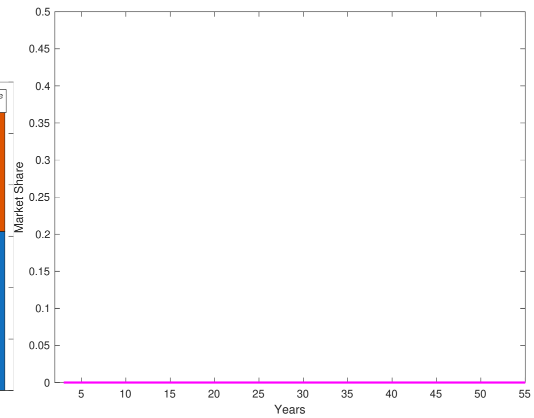



(d) Water Heating

Figure 20: Baseline Model Consumption Weighted Market Shares by End Use and Building Type




(a) Consumption Weighted Breakdown




(b) Ducted Share

Figure 21: Endogenous Movers

# B Additional Tables

| Building Size (sqft) | Ductwork Cost Share |
|---|---|
| Less than 10,000 | 23% |
| 10,000-100,000 | 51% |
| Greater than 100,000 | 50% |

Table 8: Share of ductwork in total installation costs for buildings without ductwork

| Units | SF det. | SF att. | 2 | 3-4 | 5-9 | 20-49 | >50 | Total |
|---|---|---|---|---|---|---|---|---|
| Electricity | 14 | 22 | 47 | 39 | 59 | 58 | 54 | 42 |
| Natural Gas | 86 | 78 | 53 | 61 | 41 | 42 | 46 | 48 |

Table 9: Space Heating Fuel Type by Residential Building Type

| | Single-Family | Multi-Family | Commercial |
|---|---|---|---|
| Electricity | 19.1 | 54.4 | 10.8 |
| Natural Gas | 79.7 | 41.1 | 66.5 |
| Fuel Oil | 1.1 | 2.0 | 0.7 |
| Propane | 0.2 | 0.8 | 0.4 |

Table 10: Shares of heating fuel by dwelling type

| | Share | Gwh |
|---|---|---|
| Space Heating Commercial | 30.7 | 2352 |
| Space Heating Single-Family | 27.5 | 2104 |
| Space Heating Multi-Family | 7.3 | 555 |
| Water Heating Commercial | 9.1 | 700 |
| Water Heating Residential | 7.4 | 572 |
| Interior Equipment Commercial | 17.9 | 1367 |

Table 11: Annual total gas consumption and shares by end use and building type in Restock and ComStock, GWh stands for Gigawatt hours.

All buildings

| | Electric Heat | Gas Heat | Unconditional |
|---|---|---|---|
| Gas Cooking | 3 | 33 | 20 |
| Gas Drying | 1 | 11 | 6 |
| Gas Water Heating | 14 | 80 | 51 |

Table 12: Shares of dwelling using gas for certain end uses conditional on fuel used for space heating, all buildings

| Single Family Buildings | | | |
|---|---|---|---|
| | Electric Heat | Gas Heat | Unconditional |
| Gas Cooking | 3 | 33 | 20 |
| Gas Drying | 1 | 11 | 6 |
| Gas Water Heating | 14 | 80 | 51 |

Table 13: Shares of dwelling using gas for certain end uses conditional on fuel used for space heating, single-family homes

| Multi Family Buildings | | | |
|---|---|---|---|
| | Electric Heat | Gas Heat | Unconditional |
| Gas Cooking | 3 | 33 | 20 |
| Gas Drying | 1 | 11 | 6 |
| Gas Water Heating | 14 | 80 | 51 |

Table 14: Shares of dwelling using gas for certain end uses conditional on fuel used for space heating, multi-family homes

| Residential Buildings | |
|---|---|
| No Gas | 36.7 |
| Some Gas Use | 63.3 |
| Total | 100 |

Table 15: Residential buildings that use natural gas

# C Scaling NREL consumption

DC commercial customer gas consumption as reported in 2018 (the reference year for building datasets) EIA data is $\sim$5 TWh. The corresponding usage in ComStock is $\sim$1 TWh.[21]. This discrepancy is so large that we need to correct our dataset in order to adequately capture aggregate dynamics of gas disconnections. We use a complementary dataset from the District Department of Energy and Environment that is used for reporting purposes in the District Building Energy Performance Standard program and its Energy Benchmarking program. The dataset covers all buildings that exceed 50,000 square feet in gross floor area. We use this dataset to compare energy use intensities by building type with what is reported in the ComStock dataset. In Table 16, we show that ComStock consistently has lower energy use intensities across all building types. To correct for this, We multiply the gas consumption variable in ComStock by the ratio of gas energy use intensities by building type in BEPS to ComStock.

[21] EIA reports 16.6 billion cubic feet of commercial gas usage in DC for the reference year 2018, equivalently 4.87 TWh

| | floor space | gas EUI | electric EUI |
|---|---|---|---|
| office | | | |
| BEPS | 151.1 | 1.7 | 15.3 |
| NREL | 165.0 | 1.4 | 14.4 |
| hospital | | | |
| BEPS | 73.4 | 50.9 | 32.6 |
| NREL | 88.0 | 1.7 | 22.5 |
| hotel | | | |
| BEPS | 25.2 | 13.7 | 16.9 |
| NREL | 35.8 | 7.2 | 15.9 |
| school | | | |
| BEPS | 5.9 | 19.8 | 32.5 |
| NREL | 8.9 | 4.9 | 9.8 |
| warehouse | | | |
| BEPS | 1.5 | 5.8 | 9.0 |
| NREL | 2.0 | 0.9 | 5.2 |

Table 16: Energy intensities of selected commercial buildings larger than 50,000 square feet in ComStock and the BEPS benchmarking database for 2018. Floorspace is measured in millions of square feet. EUI (energy intensities) are in kwh per square foot.

Having corrected the energy use intensities, we check whether the aggregate building floor area in ComStock and RESTOCK matches that from other sources. In Table 2, we compare NREL's floor area data with the Office of Tax Revenue's Computer Assisted Mass Appraisal (CAMA) dataset's measures of floor area. The table also reports gas consumption compared to EIA data once the intensities are scaled up using the ratios calculated from Table 16. We find that after correcting the gas energy use intensities in ComStock, the ratio of gas consumption in ComStock relative to commercial gas use in the EIA data roughly matches the ratio of the floor area in ComStock relative to CAMA. In other words, our rescaled Com-

Stock commercial gas usage data is only about half of what is reported in the EIA data likely because the buildings modeled in ComStock account for only half of actual commercial building floor area.

Our approach to correcting gas usage reported in the ComStock dataset to match aggregate EIA commercial customer gas usage is described in detail below.

- We compare buildings with floor space greater than 50K square feet in ComStock to DC benchmarking data in 2018, excluding multifamily buildings which are considered residential buildings in NREL classification. As Table 16 shows, total floor area is similar across datasets. Electricity use intensities are similar between ComStock and BEPS data (except for schools), the gas intensities are lower in ComStock than in BEPS for each building type. Wilson et al. (2022) appears to have adjusted the electric intensities, but we conjecture that the gas intensities have not been adjusted.

- We compare 7 common categories of building types in ComStock with their counterpart in BEPS: hospital, warehouse, school, outpatient facility, hotel, office, and other.

- For each of these building types, we create a ratio of gas intensities of BEPS intensities to ComStock intensities. We use these scalars to adjust upwards the gas usage of each building in ComStock. For the buildings that have no heating in ComStock, we replace the gas usage with the implied usage in the benchmarking dataset for that building type.