WHO WILL PAY FOR LEGACY UTILITY COSTS?

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ABSTRACT

The growing "electrify everything" movement aims to reduce carbon dioxide emissions by transitioning households and firms away from natural gas toward electricity. This paper considers what this transition means for the customers who are left behind. Like most natural monopolies, natural gas utilities recover fixed costs by spreading fees out over time across their customer base. In periods of a shrinking customer base, this can lead to a lack of fixed cost recovery. To shed light on these dynamics, we use historical evidence from growing and shrinking utilities. We show that in the U.S. during the period 1997-2019 there are many growing utilities, but also hundreds of utilities that experienced sustained periods of customer loss. We then study how the loss of customers impacts utility operations and finances. Utilities that lose customers maintain their pipeline infrastructure even as the customer base financing their operations is shrinking. As a result, historical capital cost recovery and some operations and maintenance costs do not decrease. In keeping with this, we observe that utility revenues shrink, but less than one-for-one -- indicating higher bills for remaining customers. We highlight resulting equity implications -- both across income levels and across racial groups -- of the current push for building electrification and other energy transition policies. We conclude by discussing alternative utility financing options, such as recouping fixed costs through taxes rather than rates.

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1 Introduction

Natural monopolies typically recover fixed costs by spreading fees out over their customer base across time, whether through per-unit fees, per-customer fees, or a combination. In the U.S., this is true of privately-held utilities, municipally-run utilities, and utilities run by other governmental agencies (e.g., federal) across a broad range of goods: electricity, natural gas, water, wastewater services, garbage collection, and more. Not discussed much in the literature is that in times of a shrinking customer base, this can lead to difficulties recovering fixed costs; either prices must rise, or costs (such as maintenance of infrastructure) must be cut.

This issue is currently coming to a head with U.S. natural gas utilities due to a growing number of policies aimed at transitioning customers away from natural gas and towards electricity. Building electrification has been called "a linchpin solution for decarbonization" (National Academies of Sciences, Engineering, and Medicine, 2021), and recent proposals for a transition to carbon neutrality rely on scenarios in which the vast majority of the building stock is transitioned to all-electric in a few decades (Larson et al., 2020; National Academies of Sciences, Engineering, and Medicine, 2021; Williams et al., 2021). A number of municipalities have adopted regulations to encourage electrification, including bans on natural gas in new construction, electric-preferred building codes, and subsidies for heat pumps.

This paper considers what such a transition would look like for the customers who are left behind. The current push for building electrification is still in its early stages, so it is too soon for an empirical analysis of how utility behavior responds to this policy push. Instead, we use historical evidence from growing and shrinking utilities. Although mostly driven by reasons other than building electrification, this evidence is nonetheless a valuable opportunity to learn how utilities change their operations and finances when customers enter or exit.

First, we demonstrate that both customer base growth *and* customer base loss are com-

monplace among U.S. natural gas distribution utilities during our sample period of 1997-2019. We observe, for example, nearly 250 utilities that experience five or more consecutive years of customer base decline. Although the total number of natural gas customers in the U.S. has increased 25 percent over this time period, many specific regions have lost population, and we show that customer base declines are associated with net migration patterns. For example, Alabama Gas Corp – a large utility serving Birmingham and much of central Alabama – has consistently experienced a shrinking customer base at the same time the city of Birmingham has lost population.

Second, we examine what these customer base changes mean for utility operations. For most natural gas distribution utilities, the pipeline infrastructure is the single largest asset and the single largest fixed cost. We compile annual data on the total number of pipeline miles operated by each utility, and test how this responds to changes in the customer base. We find that when utilities are growing, they add pipelines. A ten percent increase in the number of residential customers leads to a four percent increase in the length of the distribution network. However, when utilities are shrinking, they do not remove pipelines. A ten percent decrease in the number of residential customers has a precisely estimated zero percent effect on the length of the distribution network. Utilities *add* pipelines but rarely *remove* them, even when the customer base from which to recover costs is shrinking.[1]

Third, we test for changes in utility finances. As with pipelines, we find that utility revenues respond asymmetrically to changes in the customer base. New customers lead to one-to-one revenue increases, with a ten percent increase in residential customers increasing revenues by ten percent. In contrast, customer losses lead to a less than one-to-one decrease in revenue, with a ten percent decrease in residential customers decreasing revenues by only about five percent. This pattern implies that remaining customers make up about half of the lost revenue through increased rates.

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[1]In some ways this is related to "durable housing" and the idea that it is relatively easy to build more homes as demand increases, but that those homes remain even after demand decreases (Glaeser and Gyourko, 2005). Utility infrastructure is different, however, in that unlike homes there is no market by which pipelines are bought and sold, and thus nothing analogous to housing prices.

These increased bills for remaining customers have significant equity implications. We show that many of the utilities with the most customer loss serve cities with high rates of poverty. We also show high rates of customer base loss in cities with large African-American populations; in parts of the Rust Belt and Appalachia; and in some rural areas. Thus the places where remaining customers face higher prices may be places with broader economic challenges, making it even more difficult for these remaining customers to pay rising bills.

Finally, we use our empirical estimates to predict how customer bills will increase in the future for different levels of building electrification. We find that bill impacts are highly non-linear. For a 15 percent reduction in residential gas customers, we calculate bill increases of around \$30 per year for remaining customers – but for a 90 percent reduction in customers, we calculate bill increases of over \$1,500 per year. To understand the changes in utility expenditures that could lead to these outcomes, we examine data on categories of expenditures for a sample of large utilities. We show that a substantial portion of expenditures are fixed costs that, at least in the short-run, are unlikely to change as customers leave service. This includes returns for investors on past capital expenditures, maintenance of existing pipelines, and some administrative expenses such as pension payments. Finally, we discuss various financing alternatives, including paying for fixed costs through general taxes, and we discuss likely impacts for remaining customers.

Several features of the natural gas market make it a particularly good setting for such an analysis. First, natural gas distribution is a quintessential natural monopoly, making it an ideal setting for studying what happens to legacy utility costs during market transitions. Second, even relative to other utilities like electricity distribution companies, both the physical pipeline infrastructure and financial data such as revenue are particularly well observed, a product of the highly regulated nature of the industry. We note that the industry is regulated in part precisely because it is a natural monopoly, but also because proper maintenance of the distribution network is important for safety and environmental reasons. Finally, natural gas has historically provided important services (heating, cooking, and water heading) to

a large portion of U.S. households and firms. This is a major energy market in the U.S., serving 70 million households in addition to millions of commercial establishments. Sales in this sector to residential and commercial customers totaled nearly $70 billion in 2019.

Our paper contributes to a broader literature on infrastructure investment, fixed cost recovery, and the optimal regulation of natural monopolies. This literature has emphasized a number of regulatory challenges in this environment, including how to create incentive-compatible regulations that allow for cost-minimization without sacrificing infrastructure quality or other goals (Bonbright, 1941; Averch and Johnson, 1962; Viscusi, Vernon and Harrington, 2005; McRae, 2015). We consider a previously understudied dynamic issue: the role of net migration and depopulation in recovery of legacy infrastructure costs.

While we focus on natural gas in our empirical example, the mechanisms we document are likely to apply to any natural monopoly that recovers fixed costs from ratepayers. Thus our paper can contribute to a better understanding of an issue that applies broadly across many different natural monopolies: urban transit; water quality; landlines to wireless; rooftop solar; etc.[2,3]

Our paper also contributes to a broader literature on the economics of natural gas utilities. Rate design has been explored by Knittel (2003); Davis and Muehlegger (2010); Borenstein and Davis (2012); Auffhammer and Rubin (2019); and Hausman (2019).[4] Hausman

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[2]Cost recovery difficulties associated with customer base changes have been pointed out for water utilities (Beecher, Mann and Landers, 1990; Beecher, Dreese and Landers, 1992; Beecher, 2020; Swain, McKinney and Susskind, 2020). Faust, Abraham and McElmurry (2016) investigates potential solutions for water utilities, as well as public attitudes towards them. However we are not aware of in-depth empirical analyses of these issues of the sort we conduct here on natural gas. Gabel and Burns (2012) similarly discuss cost recovery issues in the transition from landlines to wireless and voice-over internet. Finally, the asymmetries between growing and shrinking cities have been investigated by Galster (2017), who notes the importance of infrastructure costs but does not examine them empirically.

[3]Note that these issues *do not* typically come up with retail choice of natural gas service. In retail choice states, the customer is able to select a provider of the gas product, but continues to pay pipeline-related costs to the same local distribution company, so fixed cost recovery has not changed.

[4]Knittel (2003) examines pricing decisions of gas-only, electric only, and combined gas and electric firms, finding some cross-subsidization across product types and customer types. Davis and Muehlegger (2010) show that fixed costs are generally recovered through volumetric mark-ups more than through fixed fees. Borenstein and Davis (2012) further explore the equity implications of these mark-ups. Auffhammer and Rubin (2019) show differing demand elasticities in summer and winter months, suggesting a role for differential fixed cost recovery across seasons. Hausman (2019) shows that fixed cost recovery varies over time in ways that smooth out bill totals.

and Muehlenbachs (2019) look at regulatory impacts on the incentives for environmental and safety protection. Perhaps most closely related is the work on bypass, which examines industrial customer retention (Laffont and Tirole, 1990), for instance at the time of deregulation of wholesale natural gas prices.

Our paper speaks directly to policy issues around building electrification. Davis (2021) empirically examines the customer decision-making around home heating technologies, calculating willingness to pay to avoid an all-electric transition. A number of white papers have examined costs and benefits of building electrification in California (Bilich, Colvin and O'Connor, 2019; Greenlining Institute, 2019; Gridworks, 2019; Mahone et al., 2019; Aas et al., 2020). But we are not aware of any statistical analysis applying to the broader U.S., and we note that many of the issues we raise do not appear in the California-specific results (the impact on majority-African American cities; the impact on municipal utilities; etc.).

Our work is also related to a recent and growing literature on equity issues in energy transitions. Most closely related is the work in this field examining how rooftop solar can push fixed cost recovery onto low-income customers (Burger, 2019; Borenstein, Fowlie and Sallee, 2021) – this is a function of high mark-ups in high-solar penetration areas like California. In contrast, the mechanism in our paper is a function of customer losses, which applies even when fixed costs are recovered through fixed fees. Thus the standard rate reforms that are frequently suggested for rooftop solar would still lead to fixed cost recovery issues and equity issues in our setting. A similar mechanism could apply to the electricity sector in future scenarios with so-called "grid defection," in which the installation of storage along with the rooftop solar allows a customer to disconnect from an electric utility altogether (Gorman, Jarvis and Callaway, 2020). More broadly, the equity issues we document may interact with pre-existing equity issues in residential energy markets (Reames, 2016; Carley and Konisky, 2020; Lyubich, 2020).

Finally, our results on economic and racial inequities also contribute to the literature on rural depopulation (Johnson and Lichter, 2019) and on shrinking cities (Beauregard,

2009), where a combination of economic forces and racial antagonism have been identified (Boustan, 2010; Galster, 2017). We empirically show that these broad migration patterns in the United States can directly the impact the ability of utilities to provide the basic services that households require. While we focus on natural gas, similar mechanisms are expected in water and other utility services.

2 Data

2.1 Data Sources

Our empirical analysis takes advantage of the unusually rich data available for the U.S. natural gas distribution sector. The highly regulated nature of this sector means that detailed information is available from multiple government agencies, including the Department of Energy and the Department of Transportation. Thus we are able to observe key aspects relating to both the physical infrastructure and to the utilities' financials, including sales, revenues, and prices.

Our core dataset is an annual panel describing essentially the universe of U.S. natural gas distribution utilities for the years 1997 to 2019. Most of this information comes from an annual census of natural gas distribution utilities conducted by the U.S. Department of Energy's Energy Information Administration (EIA).

This EIA-176 dataset reports on customer count, volume sold, and revenue collected by end-user sector (e.g. residential versus commercial). It also reports the utility's ownership structure (investor-owned, municipal, etc.).[5] For companies that operate across multiple states, there is a separate entry for each state's operations. From EIA, we also observe the

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[5]We simplify the designations somewhat by combining some categories. For instance, we combine "investor-owned utilities" and "privately-owned utilities," regardless of whether they are, for instance, publicly traded. We also group into the "municipal" category some rural cooperatives and a few other kinds of government-run agencies such as county-run utilities. Note also that the raw data appears to have some reporting errors, which we correct. Details on this are in the Appendix.

state-level citygate price.[6] This represents the price (in dollars per mcf) paid by utilities in that state when purchasing natural gas. We deflate all revenue and prices by the annual consumer price index from FRED, reporting all dollar amounts in 2020 dollars.

One of our primary outcome variables is "net revenue," which we calculate by taking total utility revenue and subtracting off the portion of revenue that is collected to pay for purchasing natural gas. These additional revenues are collected to pay for all non-gas costs, including pipeline investments, maintenance and operations, administrative salaries, and a return for investors. Whereas natural gas purchases can be easily adjusted upward and downward in response to changes in customer counts and fluctuating consumption levels, this net revenue stream is how the utility pays for fixed costs. An additional advantage of focusing on net revenue is that it means we will be able to largely ignore variation in natural gas commodity prices, weather, macroeconomic shocks, and other factors that lead to short-run fluctuations in utility total revenue.

Our other key data source is an annual utility-level census (1997 to 2019) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the Department of Transportation. Natural gas distribution utilities are required under federal law to submit annual reports to PHMSA. This information is used by PHMSA and other government agencies to enforce pipeline safety regulations, track and investigate incidents, and plan inspections. Utilities are required to submit separate reports for each state in which they operate.

The primary variable we use from this dataset is the total "distribution main mileage" per utility per year. Distribution mains are the pipelines that carry natural gas under city streets. To merge the EIA and PHMSA data, we use a fuzzy string match on company names and an exact match on the state within which the company operates. We are able to match 83 percent of the EIA observations to PHMSA data (representing 87 percent of residential customers). Details on the unmatched observations are in the Appendix.

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[6]EIA assembles state-level citygate data from Form EIA-857.

Finally, we collect weather data from NOAA, specifically annual heating and cooling degree days at the state level.[7]

2.2 Summary Statistics

Summary statistics are provided in Table 1. Our sample consists of an unbalanced panel with 1,565 company identifiers, with around 1,300 companies per year. Of these, around one quarter are investor-owned utilities and three quarters municipal utilities.

The most notable thing that emerges in the summary statistics is the tremendous variation in utility size, including substantial skew. The mean number of residential customers is 41,000, but the median number is 1,000. The largest utility in our sample has nearly 6 million customers. This results from the fact that there are numerous small municipally-operated natural gas utilities around the country, at the same time that a large investor-owned utility like PG&E serves one third of all of California.

Our main specification limits the sample in a few ways, to alleviate the potential for measurement error and to bring the specification closest to our thought experiment of a utility losing some marginal amount (say, five percent) of its customers in a year due to electrification.

First, we focus on utilities for which at least 90 percent of residential customers are "bundled," rather than "retail choice." Most natural gas distribution utilities in the U.S. serve primarily bundled customers, meaning that they provide distribution service (e.g. pipeline operation) and they procure the natural gas commodity itself. In most states, less than ten percent of natural gas customers are retail choice customers, meaning that they buy natural gas from a supplier that is different from the distribution company that provides distribution services. We face one data limitation with the utilities with retail choice customers: total

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[7]The daily number of heating degrees is equal to $min(0, 65 - T)$, where T is the day's temperature in degrees Fahrenheit. We calculate the sum across days in a year. Cooling degree days (CDDs) are analogous to heating degree days, and are given by $min(0, T - 65)$. NOAA does not report these variables for the District of Columbia. We use Maryland weather for the DC utility in our sample. We similarly use the Maryland citygate price, as the EIA does not report a DC-specific citygate price.

Table 1: Summary Statistics

	N	Mean	Median	SD	Min	Max
Residential:						
Customers, '000s	29,392	41.31	1.07	229.60	0.00	5607.69
Traditional portion of customers	29,392	1.00	1.00	0.01	0.90	1.00
Dummy, customer base growing	27,671	0.51	1.00	0.50	0.00	1.00
Sales, Bcf	29,388	2.91	0.06	14.58	0.00	277.72
Average price, $/mcf	29,382	13.56	12.95	5.41	0.58	445.40
Revenue, '000,000s	28,992	27.54	0.72	129.94	0.00	3515.88
Net revenue, '000,000s	28,644	17.44	0.37	86.02	0.00	2101.42
Per customer, '000s	28,630	0.37	0.35	0.19	0.00	3.40
Per mcf	28,641	6.99	6.27	4.02	0.00	52.48
Commercial:						
Customers, '000s	29,392	3.39	0.13	14.02	0.00	213.96
Traditional portion of customers	28,083	0.99	1.00	0.05	0.00	1.00
Dummy, customer base growing	27,671	0.46	0.00	0.50	0.00	1.00
Sales, Bcf	28,080	2.03	0.04	9.03	0.00	158.12
Average price, $/mcf	28,028	12.06	11.45	4.49	0.58	181.40
Revenue, '000,000s	26,832	9.18	0.36	43.74	0.00	1078.79
Net revenue, '000,000s	27,138	8.29	0.20	39.31	0.00	1369.44
Per customer, '000s	26,859	1.70	1.27	1.57	0.00	13.00
Per mcf	27,136	5.51	4.86	3.46	0.00	42.92
Citygate price, $/mcf	29,392	6.77	6.13	2.53	2.03	36.07
Miles of pipeline, '000s	24,452	0.77	0.06	3.07	0.00	51.25
=1 if investor-owned utility	29,392	0.24	0.00	0.43	0.00	1.00
=1 if municipal utility	29,392	0.76	1.00	0.43	0.00	1.00

Note: This table provides summary statistics for our main estimation sample, an unbalanced panel of 1,565 natural gas distribution utilities over the period 1997-2019, with approximately 1,300 companies per year. The sample excludes a small number of utilities for which more than ten percent of customers buy natural gas from a retail choice provider. There are fewer observations for the two "Dummy, customer base growing" variables because they cannot be calculated for the first year a company appears in the sample. There are fewer net revenue observations for the commercial sector because some utility-year observations have zero commercial customers. There are fewer observations for the "Miles of pipeline" variable because of imperfect matches across data sources.

revenues at these utilities are not reported until the year 2008. In prior years, revenues from traditional customers are reported, but revenues from retail choice customers are not. However, volumes and customer counts are reported for both traditional and retail choice customers for all years, allowing us to impute net revenue for all customers.[8]

Second, we assign new utility identification numbers when we observe an annual resi-

[8]Specifically, we construct two versions of the net revenue variable. In the first, we assume that non-gas costs are the same for traditional and retail choice customers. So, we apply the mark-up from traditional customers to all volumes sold. This allows us to keep all utilities in all years. We limit regressions with this variable to just those utilities for whom a substantial fraction (90 percent) of residential customers are bundled customers. This allows us to keep several large utilities (like DTE in Michigan) with primarily traditional customers. In a second version of the net revenue variable, we construct net revenue using total revenue. For 1997 to 2007, this allows us only to keep utilities with zero retail choice customers. These utilities represent 96 percent of observations but only 50 percent of customers. For 2008 to 2019, we are able to keep all utilities. Across the whole sample, this unbalanced panel represents 97 percent of observations and 76 percent of customers.

dential customer change of more than 20 log points or a commercial change of more than 50 log points, as these likely indicate service territory changes, mergers, or acquisitions – the differing cut-off values across the two variables are informed by where the first and 99th percentiles lie for each variable. In specifications using differences, this will drop the year with the large change but keep subsequent years. While the EIA collects data on service territory changes, these data are not available in its EIA-176 reporting so we must infer such changes from customer counts. Thus we do not *drop* such utilities (other than the first year); we simply infer that they represent a reorganization of the utility in some way. Details and examples are in the Appendix.

Next, we drop some observations that appear to be outliers arising from measurement error; we have looked carefully at the distribution of each variable, and there is a small number of observations that look unreasonable, which we attribute to clerical errors and other reporting mistakes. In regressions using pipeline miles data, we drop utilities with less than 20 miles of pipeline mains, because growth or loss is likely to measured as very lumpy log changes.[9] We also drop observations with a change in miles of more than 100 log points.

Our net revenue measure is also somewhat subject to outliers; the raw data show both a very large maximum and a negative minimum for the per-customer and per-unit net revenue variables. However, histograms otherwise show a distribution that is fairly close to log-normal. In our main specification, we drop these outliers.[10]

Finally, we focus on utility-years that are part of at least a two-period sustained growth or loss. That is, we drop observations where a utility grows in one year, shrinks in the next, etc. We do this for two reasons. First, for our thought experiment of a utility losing customers because of electrification, we are interested in sustained patterns of loss. Second,

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[9]For instance, if the utility records in rounded integer values, no change will be recorded for a change from 10.2 to 10.3 miles, but a large log change will be recorded for a change from 10.4 to 10.5 miles. In the raw miles data, utilities vary in the level of precision they report, even across years within the same utility.

[10]We define net revenue outliers in four ways. We drop net revenue observations less than or equal to zero; year-on-year net revenue changes greater than 200 log points; net revenue *per customer* observations that are more than ten times the median value; and net revenue *per unit of gas* observations that are more than ten times the median value. In the Appendix, we shows results keeping these observations.

if the miles and customer counts are measured at different times in a year, the year-on-year changes may not match up in time. This would be most concerning if a utility grows in one part of a year but shrinks in another part of the year; it is less concerning if the utility is on a continued trajectory. In the Appendix, we shows results relaxing each of these sample choice criteria.

3 Growing and Shrinking Utilities

We are interested in how utility operations and infrastructure investments respond to changes in the size of the customer base. Of course, historical evidence of these patterns is only valuable to the degree that utilities actually experience meaningful changes in the customer base. In this section, we describe the patterns of customer base growth and loss over the past two decades. As can be seen in Table 1, the customer base is shrinking in *half* of our utility-year observations. Absent from many policy discussions around the energy transition is ex-post evidence on how utilities have managed customer base loss, but we show that such experiences are commonplace, and that lessons can be drawn from these utilities.

3.1 Preliminary Graphical Evidence

Figure 1 plots residential customer counts over time for a random 4% of utilities. We normalize each utility's count to 1 at the beginning of the sample. As illustrated by the figure, there is a wide variety of experiences across utilities. Even though the U.S. population is growing, a substantial portion of utilities lose customers over this period. There are many utilities that grow by 20% or more, but also many utilities that shrink by 20% or more.

The figure also reveals considerable persistence in both growth and loss. Recall that Table 1 shows that half of our observations involve customer base loss; Figure 1 illustrates that this is not due to one-year "blips." We observe prolonged periods of both growth and loss. For example, we observe around 320 utilities that experience five or more consecutive

Figure 1: We Observe Shrinking and Growing Utilities
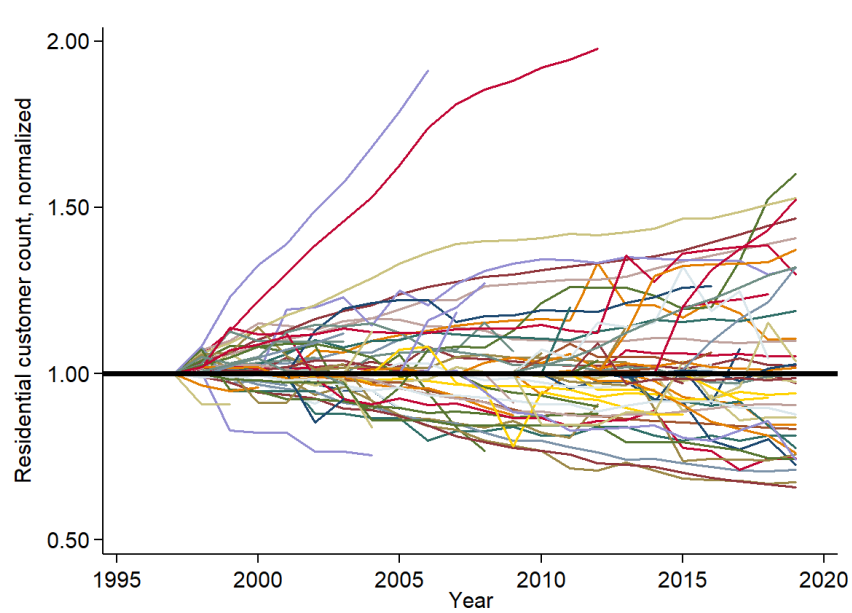
Note: This figure shows residential customer counts for a random 4% of utilities, normalized to 1 in their first year (1997 for many; later years for some). Large changes have been assigned a new utility id to account for the possibility of mergers and acquisitions. The graph has been zoomed in to a maximum of 2.0 on the y-axis; the two utilities with the largest growth continued on an upward trend (not shown).

years of customer base growth, but also around 250 utilities that experience five or more consecutive years of customer base loss.

3.2 What Types of Utilities Are Growing?

To better understand the patterns driving these periods of growth and loss, we summarize in Table 2 the "proportion growing" variable across different utility types. Investor-owned utilities are more likely to be growing than are municipal utilities, but even for investor-owned utilities more than one quarter of utility-year observations are not growing. The high loss portions in municipally-owned utilities may be related to rural depopulation in the U.S., discussed further below.

Similarly, the utilities that are largest in the first year they appear in our sample are much more likely to be growing, and the smallest utilities are more likely to be shrinking;

Table 2: What Types of Utilities are Growing?

	N	Proportion With Residential Growth
All utility-years	24,543	0.52
By ownership type:		
Investor-owned utilities	6,094	0.71
Municipally-owned utilities	18,449	0.46
By number of residential customers in first year:		
1 million or more	156	0.92
100,000 − 1 million	1,811	0.82
10,000 − 100,000	2,695	0.75
1,000 − 10,000	8,710	0.56
100 − 1,000	10,678	0.39
1 − 100	493	0.31
By time period:		
1997–2007	10,921	0.54
2008-2019	13,622	0.51
By geographic region:		
New England (CT, MA, ME, NH, RI, VT)	504	0.89
Pacific (CA, OR, WA)	465	0.83
Mountain (AZ, CO, ID, MT, NM, NV, UT, WY)	1,230	0.74
Middle Atlantic (NJ, NY, PA)	642	0.70
East North Central (IL, IN, MI, OH, WI)	3,134	0.55
West North Central (IA, KS, MN, MO, ND, NE, SD)	4,541	0.54
East South Central (AL, KY, MS, TN)	5,483	0.53
South Atlantic (DC, DE, FL, GA, MD, NC, SC, VA, WV)	3,640	0.48
West South Central (AR, LA, OK, TX)	4,904	0.37

Note: This table describes our main estimation sample, classifying observations along several different dimensions. For each subset of the sample, the table reports the total number of utility-year observations as well as the proportion of utility-year observations for which the residential customer base grew.

this pattern is monotonic across the buckets of size we display in Table 2. The "break-even" size at which utilities are equally likely to be growing or shrinking is 1,000 to 10,000 initial customer count.

Finally, we see a clear geographic pattern emerge. The regions with the most customer growth include New England and the West ("Pacific" in the Census region nomenclature), with over 80 percent growth in each. The regions with the most customer loss include the South Atlantic and the Gulf Coast/Oklahoma/Texas area ("West South Central" in the Census region nomenclature). These geographic differences are difficult to interpret by themselves, because different regions have different utility *sizes* and different utility ownership patterns, for historical reasons. As such, we next analyze these regional differences separately for investor owned utilities and municipal utilities.

Figure 2: Regional Patterns in Residential Customer Base Changes

(a) Investor-Owned Utilities   (b) Municipal Utilities
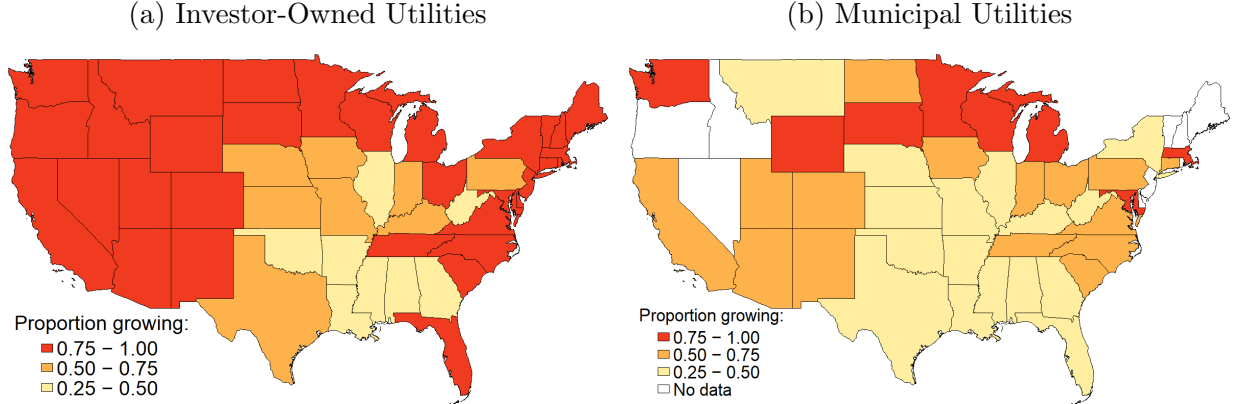
Note: These maps show the portion of utility-year observations with residential customer growth separately for investor-owned and municipally-owned utilities. Red and orange reflect states (such as in the West) where utilities tend to be growing; yellow reflects areas where utilities tend to be shrinking. White states in panel (b) do not report any municipal utilities.

3.3   Additional Geographic Evidence

In Figure 2, we provide two maps aimed at better understanding the geographic pattern. We plot, at the state level, the proportion of utility-year observations with residential customer growth for investor owned utilities (Panel A) versus municipal utilities (Panel B). The high proportion of growth in New England reflects that the region is served only by investor-owned utilities and not by any municipal utilities. In contrast, the high proportion of growth in the Pacific region is seen in both the investor-owned and municipal utility maps.

We unfortunately lack detailed service territory data across time for the universe of natural gas utilities. However, these maps suggest that customer base changes are somewhat correlated with regional population changes. Western states such as New Mexico, Washington, Utah, Nevada and Idaho experienced growth at *all* investor-owned utilities in *all* years; all of these states experienced substantial population growth over the 1997-2019 time period, with Nevada, Arizona, and Utah experiencing the largest population growth rates in the country. In contrast, West Virginia *lost* population over this time period, and Southern states like Mississippi and Louisiana had fairly slow population growth rates compared to much of the country.

To corroborate this pattern, we merged population estimates from the U.S. Census Bu-

reau with the geographic boundaries of U.S. natural gas distribution utilities as of 2017.[11] This exercise is imperfect because it fails to capture changes in service territory boundaries over time and because overlapping service territory boundaries and other issues introduce measurement error. Nevertheless, we are able to show using these merged data that population changes are highly predictive of changes in residential customer counts, particularly for larger utilities. Although there are certainly many factors driving residential customer counts, it seems clear that population changes are the primary driver. See Appendix Table A2.

3.4 Qualitative Evidence from Selected Utilities

The correlation between customer count changes and population changes matches anecdotes from several utilities. In a rate case filing for DTE – a large utility serving Detroit and Southeast Michigan – one analyst testified that "The poor local economic conditions in DTE Gas's service territory as well as declining population exacerbate the effect of declining sales in increasing the downside risk that DTE Gas may not be able to fully recover its fixed costs."[12] National Fuel, serving upstate New York and parts of Pennsylvania (such as Pittsburgh) similarly argued that "it grapples with a declining population and a weak economy in its service territory."[13] A rate case for Centerpoint Arkla (Arkansas) discusses related challenges, with a growing number of pipeline miles but a decreasing number of customers: "declining revenues and increasing costs make it difficult, if not impossible, for

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[11]Population estimates by census block group from the decennial census 2000 and five-year data from the American Community Survey 2015-2019 were extracted from IPUMS National Historical Geographic Information System (Manson et al., 2020). These data were then merged with information on the geographic boundaries of about 1,200 U.S. natural gas distribution utilities as of 2017 from the Homeland Infrastructure Foundation-Level (HIFLD) Database, `http://hifld-dhs-gii.gov/HIFLD`. This HIFLD data were constructed by Oak Ridge National Lab using information from EIA-176, corporate websites, maps, American Gas Association data, and other sources. The HIFLD data provide a snapshot of utility service boundaries as of 2017 and we are not aware of any similar national-level data for other years.

[12]LARA Filing U-17999-0002. 18 December 2015. DTE Energy Company. Testimony, Case Number U-17999. `https://mi-psc.force.com/s/filing/a00t0000005pl9SAAQ/u179990002`. Accessed 18 May 2021.

[13]Robinson, David. 8 November 2001. "NFG sees new pipelines as boost to U.S. security." *Buffalo News*. `https://buffalonews.com/news/nfg-sees-new-pipelines-as-boost-to-u-s-security/article_7eab74c6-5791-54fd-82a8-9034d7ecdca2.html`. Accessed 2 February 2021.

the Company to recover its cost of service."[14]

An especially compelling case study is that of Philadelphia Gas Works, the largest municipally-owned gas distribution utility in the country. A white paper details the financial struggles, noting: "The challenging demographics of PGW's customer base are a byproduct of Philadelphia's shrinking population and high concentration of poverty. The City has lost nearly 30 percent of its population over the past half-century." The report goes on to note implications for prices that we discuss further below: "with a declining customer base characterized by a high concentration of poverty, the need for additional rate increases to cover fixed expenses seems inevitable."[15]

Municipal utilities tend to serve rural populations, and as such their customer base loss (with the exception of some urban utilities like Philadelphia Gas Works) may reflect rural depopulation. For this utility type, Cairo Public Utility Co of Illinois provides a clear case study. A series of news articles from 2017 summarizes the financial challenges facing this rural utility and the high bills facing its customers. As one of the articles notes, "[utility administrators] said that part of the issue with Cairo Public Utility Co. is that they are managing a system that was originally built for 20,000 people, and today Cairo is home to only about 2,500."[16]

In contrast to these anecdotes from rural areas, the Rust Belt, and parts of the Southeast, companies in the Southwest and the West note a very different experience. For instance, the annual report for Southwest Gas (serving Arizona, Nevada, and California), notes "Southwest Gas remains among the top utilities for customer growth with 26,000 net new customer additions in 2015. This is due in part to a growing economic recovery across Southwest Gas

[14]Docket No. 04-121-U. Filed 3 December 2004. `http://www.apscservices.info/pdf/04/04-121-u_35_1.pdf`. Accessed 2 February 2021.

[15]Economy League of Greater Philadelphia. 2008. "The Philadelphia Gas Works: Challenges and Solutions." `https://www.pewtrusts.org/en/research-and-analysis/reports/2008/10/21/the-philadelphia-gas-works-challenges-and-solutions`. Accessed 18 May 2021.

[16]Smith, Isaac. 26 July 2017. "For citizens and business owners, high utility bills are a way of life in Cairo." *The Southern.* `https://thesouthern.com/news/local/for-citizens-and-business-owners-high-utility-bills-are-a-way-of-life-in-cairo/article_103a8531-55bd-54a3-9415-3fae8a319ef6.html`. Accessed 3 February 2021.

service territories," going on to describe how projected population growth rates in its major metro areas are much higher than for the U.S. as a whole.[17] Similarly, Questar Gas's annual report notes "The population of the Company's service area in Utah continues to grow faster than the national average."[18]

Overall, the main takeaway is that many U.S. natural gas utilities have faced years of customer base loss. This is especially true of small utilities and of municipal utilities, and a major factor appears to be population changes. The experience of these utilities might be informative as policies seek to transition building energy use from natural gas to electricity. We next turn to an empirical examination of utility operations and finances.

4 Results

4.1 Pipelines

We begin by examining the relationship between the physical pipeline network and the number of customers. Figure 3 plots the relationship between the log change in miles and the log change in residential customer counts. The figure also shows a histogram of log residential customer count changes – matching the summary statistics in Table 2, the histogram shows that roughly half of residential customer changes are positive and half are negative.[19]

A clear positive relationship emerges in Figure 3. As utilities grow, they add pipelines. However, a clear asymmetry is also visible. In addition to the scatterplot (with markers sized by initial utility size), we overlay a lowess smoother. Importantly, this lowess smoother does not *impose* any asymmetry – but one emerges naturally. With growth in the residential count, i.e. on the right-hand side of the plot, there is an upward sloping, nearly linear fit

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[17]Southwest Gas 2015 Annual Report. `https://www.swgas.com/www/flipbooks/Swgas_Annual_Report_2015/mobile/index.html#p=2`. Accessed 18 May 2021.

[18]Questar Gas 1999 Annual Report. `https://www.sec.gov/Archives/edgar/data/68589/0000068589-99-000002.txt`. Accessed 18 May 2021.

[19]In the Appendix, we show a histogram for the change in log miles. Five percent of observations involve a reduction in log miles from one year to the next; these observations have a median log change of -0.006.

Figure 3: The Asymmetric Relationship Between Pipelines and Customers
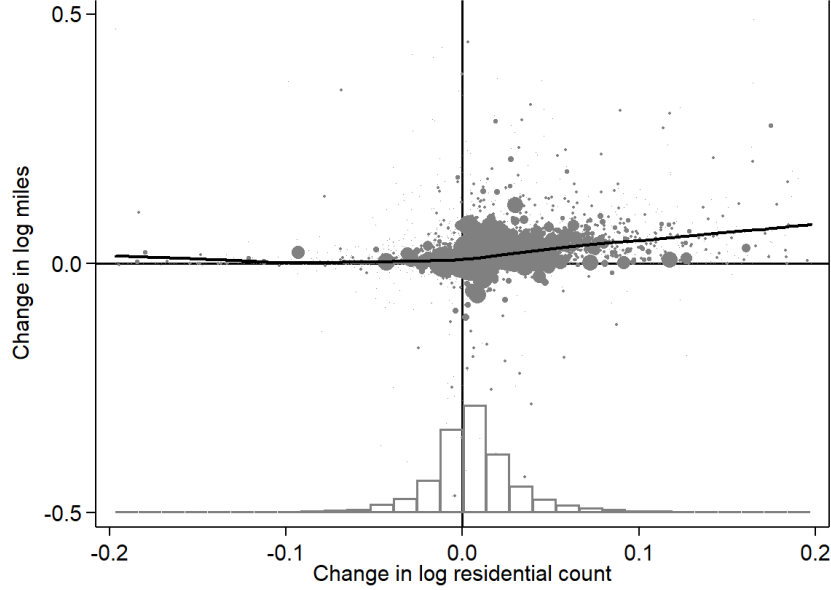
Note: The thick black line shows a lowess fit. The lowess has been fit to the full estimation sample, but the scatter plot is zoomed in to [-0.5, 0.5] on the y-axis to make the lowess slope more visible. A histogram for changes in residential counts is included at the bottom of the figure.

between the log growth in miles and the log growth in residential customers. With loss in the customer count, i.e. on the left-hand side of the plot, there is essentially no change in the log mile count. There is a slight upward tick on the far left side of the plot, but there are almost no observations in that region, as shown in the histogram along the bottom. In contrast, there is a substantial mass of observations closer to the origin, i.e. at around zero to five log points of loss. That is, when a typical utility loses customers, it experiences *no change* in its pipeline miles.

We next formalize this intuition with two sets of regressions. First, we regress the log change in miles on the log change in residential and commercial counts. The regression takes the form:

$$\Delta \ln M_{i,t} = \alpha + \beta \Delta \ln R_{i,t} + \gamma \Delta \ln C_{i,t} + \varepsilon_{i,t}, \tag{1}$$

where $M_{i,t}$ is the miles of pipeline mains at utility i in year t, R is the count of residential customers, and $C_{i,t}$ is the count of commercial customers. Standard errors $\varepsilon_{i,t}$ are clustered

by utility, to account for serial correlation arising from the fact that utilities tend to be in growing or shrinking periods for multiple years in a row, reflecting broader demographic trends.

We use logs to ease comparisons across large and small utilities. We use differencing because we are interested in what happens as utilities grow or shrink, rather than in cross-sectional differences between large and small utilities. One could instead use fixed effects, which we show in the Appendix. In our baseline specification, we do not use any controls; as we do not expect there to be factors that require a utility to grow its pipeline network other than the growth of its customer base, but we examine specifications with additional controls in the Appendix.

Table 3, Column 1 shows the estimation results for Equation 1. A ten percent increase in the residential customer count is associated with a 2.5 percent increase in pipeline miles, statistically significant at the one percent level. A ten percent increase in the commercial customer count is associated with a 0.3 percent increase in pipeline miles, statistically significant at the one percent level. The magnitude difference between the residential and commercial estimates is intuitive: as shown in Table 1, the typical utility has 10 times as many residential customers as commercial customers, so a one percent increase in residential customers translates into a much larger increase in customers than does a one percent increase in commercial customers. This can be seen by looking at level effects of the estimates at the median values. The elasticity of 0.25 for residential customers translates into 1.1 miles for every 100 residential customers, as shown at the bottom of the table. The elasticity of 0.03 for commercial customers translates into 1.3 miles for every 100 commercial customers (not shown, for space).

4.2   Asymmetric Impacts

The first regression results, however, mask important differences between periods of customer base growth and loss. Once a mile of pipeline is built, a utility is very unlikely to remove it,

Table 3: The Impact of Customer Base Changes on Pipeline Infrastructure

	(1) Miles (log)	(2) Miles (log)
Residential customers (log)	0.249***	
	(0.023)	
Commercial customers (log)	0.034***	
	(0.011)	
Residential customers (log), when growing		0.385***
		(0.037)
Residential customers (log), when shrinking		-0.001
		(0.039)
Commercial customers (log), when growing		0.028
		(0.020)
Commercial customers (log), when shrinking		-0.007
		(0.016)
Constant	0.011***	0.003***
	(0.000)	(0.001)
Observations	9,538	9,538
R^2	0.04	0.06
Miles per 100 residential customers	1.09	
When growing		1.68
When shrinking		-0.01
P-value: null of symmetry		
Residential		0.00
Commercial		0.18
Combined		0.00

Note: This table shows point estimates and standard errors corresponding to two separate least squares regressions. In both columns the dependent variable is the regression of miles of pipeline mains in logs. The regressions are estimated in differences. The p-value rows show the results of tests that the growing and shrinking coefficients are equal to one another. The "miles per 100 customers" rows show the marginal effects at the median values of the dependent variable and the median customer count. The sample covers 1997-2019, with around 600 companies per year. Residential customer log changes of more than 0.2 (in absolute value) and commercial log changes of more than 0.5 (in absolute value) are dropped, as they may indicate service territory changes. Sample is limited to periods when the utility grew or shrank for two or more consecutive years, matching the policy thought experiment in the paper. Alternative samples and specifications are shown in the Appendix. Standard errors are clustered by company.

or to stop selling gas via it. This is particularly true if customer base loss is geographically dispersed, for instance if driven by urban vacancy rates.

We next estimate an asymmetric specification, allowing for separate impacts of customer count changes when they are positive versus negative:

$$\Delta M_{i,t} = \alpha + \sum_{s \in R,C} \beta_s^+ \left(\Delta N_{i,t}^s \right)^+ + \sum_{s \in R,C} \beta_s^- \left(\Delta N_{i,t}^s \right)^- + \sum_{s \in R,C} \eta_s \mathbf{1} \left(\Delta N_{i,t}^s \right)^+ + \varepsilon_{i,t}. \quad (2)$$

For the sake of brevity, we use slightly different notation from that in Equation 1. Here $\Delta M_{i,t}$ is the log change in pipeline miles for utility i in year t. The coefficient β_s^+ is the impact of the log change in customer counts for sector s (residential or commercial) at utility i $(\Delta N_{i,t}^s)$ when the log change is strictly positive, and β_s^- is the impact when the log change is weakly negative. Because $(\Delta N_{i,t}^s)^+$ is an interaction term between the log change in customer counts $\Delta N_{i,t}^s$ and an indicator for whether than change is positive, we also include this indicator on its own: $\mathbf{1}(\Delta N_{i,t}^s)^+$. We expect the coefficient on this indicator to be close to zero, as we do not expect a differential change in miles for utilities with very slightly positive versus very slightly negative customer count changes.

Results are presented in the second column of Table 3. In keeping with the Figure 3, this specification shows statistically and economically significant asymmetry in the impact of a changing customer base on pipeline infrastructure. For each ten log point increase in the number of residential customers, the typical utility sees a four log point increase in its length of main pipelines. This coefficient is precisely estimated, and statistically different from 0.25, the coefficient in Column 1. In contrast, for *decreases* in the number of residential customers, the typical utility sees essentially no decrease in the number of miles; the coefficient is -0.001 and is not statistically different from zero. As shown at the bottom of the table, symmetry can be rejected at the one percent level for the residential specification. As in the symmetric specification, the coefficient for commercial count growth is fairly small; and again, there's essentially no response for commercial loss.

The coefficient when growing in Table 3 is statistically different from one at the one percent level. This is somewhat surprising. However, there are a few potential explanations. First, residential customers do not make up all of the utility network; one must also consider commercial customers. That is, when a utility grows its residential customer base by one percent, it is not growing its *entire* customer base by one percent. So, a test of the linear combination across sectors is a more appropriate comparison. Second, some of the time when utilities are growing, they are adding customers back in to existing neighborhoods,

and therefore not constructing new pipelines. Finally, there may be differences in the *timing* of when utilities measure the addition of new pipelines versus the addition of new customers (e.g., year-end versus mid-year). In the Appendix, we consider long-run estimates that address these latter two potential explanations, using an error correction model. The long-run results again show an asymmetry, with a larger coefficient when growing (0.65) and a near-zero coefficient when shrinking.

Finally, it is worth noting that the constant is positive and statistically significant in both columns. That is, even a utility with flat residential and commercial counts tends to see a modest increase in pipeline miles. This is consistent with some churn within the service territory, for instance if urban customers leave the city center to move to new suburban developments within the same utility's service territory.

4.3   Finances

To understand how adding or losing customers changes a utility's finances, we next examine the impact of customer base changes on utility revenues. Specifically, we regress net revenue (total revenue collected minus gas costs, as described above) on customer counts. We begin with a symmetric specification, as in Equation 1 and then proceed to an asymmetric specification, following Equation 2. As before, we drop large changes that likely indicate mergers, acquisitions, etc.

These specifications differ from the estimation with pipeline miles in a few ways. First, our sample size is larger, as we can now include the utilities for which we were unable to merge the EIA data on customer counts and revenues with the PHMSA data on miles. Second, because we observe net revenue separately for the residential and commercial sectors (whereas we only observed combined miles), we can now estimate separate regressions by sector. Finally, we introduce three new control variables.

We now include the log change in quantity sold per customer (also in differences). Utility net revenues are directly impacted by changes in quantity, as the typical utility includes a

substantial per-unit mark-up to cover fixed costs. As a result, exogenous changes in quantity consumed per customer as a result of weather changes or economic shocks can substantially change net revenues. In addition, we now include weather, both heating degree days and cooling degree days (in differences, just as the other variables are in differences). Some utilities use weather normalization, designed to decouple net revenue from weather shocks that change quantity sold. Together, this quantity sold variable and the two weather variables assist in two ways. First, they reduce noise in the net revenue variable and thus improve the precision of our estimates. Second, it is possible that *new* customers and *departing* customers have different consumption patterns. Thus growing or shrinking the customer base could change the average quantity sold and thus net revenues. By controlling for quantity sold per customer, our primary specification purges our estimates of the customer base impact of this effect on average. Thus our regression is designed to ask "if the customer base grows or shrinks, while weather remains unchanged and while the quantity sold to the typical customer remains unchanged, what happens to a utility's revenue net of gas costs?"

Results are shown in Table 4 (for brevity, we display only the coefficients on customer counts; point estimates on the control variables are shown in the Appendix, Table A5). The first two columns show that a utility that has ten log point more residential customers has a seven log point higher net revenue, on average. The estimate is slightly higher for commercial. This translates into roughly $200 of net revenue per residential customer and $1,000 per commercial customer. The right-most columns, however, show marked asymmetry, particularly for residential customers. Although the point estimates suggest less asymmetry for commercial customers, the standard errors are wide enough that we are hesitant to draw strong distinctions between customer classes.

A utility that adds ten log points more residential customers increases its net revenue by ten log points; an elasticity of one. This translates into $328 per customer (as shown at the bottom of the table), roughly matching the median net revenue per customer in our sample (Table 1). This is intuitive if utilities do not change their pricing structure when they are

Table 4: The Impact of Customer Base Changes on Net Revenue

	(1) Residential	(2) Commercial	(3) Residential	(4) Commercial
Customers (log)	0.65***	0.75***		
	(0.09)	(0.06)		
Customers (log), when growing			1.01***	0.86***
			(0.13)	(0.10)
Customers (log), when shrinking			0.47**	0.77***
			(0.20)	(0.11)
Constant	0.00*	0.00*	0.00	0.01**
	(0.00)	(0.00)	(0.01)	(0.01)
Observations	14,437	14,017	14,437	14,017
R^2	0.02	0.08	0.02	0.08
Dollars per customer	211	988		
When growing			328	1137
When shrinking			152	1015
P-value: null of symmetry			0.02	0.53

Note: This table reports point estimates and standard errors corresponding to four separate least squares regressions. The dependent variable in Columns (1) and (3) is net revenue from the residential sector, in logs. The dependent variable in Columns (2) and (4) is net revenue from the commercial sector, in logs. The regressions are estimated in differences. The p-value rows show the results of tests that the growing and shrinking coefficients are equal to one another. The "dollars per customer" rows show the marginal effects at the median values of the dependent variable and the median customer count. The sample covers 1997-2019, with around 600 companies per year. Residential customer log changes of more than 0.2 (in absolute value) and commercial log changes of more than 0.5 (in absolute value) are dropped, as they may indicate service territory changes. Sample is limited to periods when the utility grew or shrank for two or more consecutive years, matching the policy thought experiment in the paper. Alternative samples and specifications are shown in the Appendix. Standard errors are clustered by company.

growing, so that new customers translate directly into new revenues.

In contrast, a utility that loses ten log points of residential customers decreases its net revenue by only five log points. This translates into $152 per customer. The growing and shrinking estimates are statistically different from one another at the five percent level, as shown in the bottom row of the table. That is, utilities with shrinking customer bases do not experience shrinking revenues at a one-for-one rate. This indicates that revenue collection from the customers that remain with the utility must be increasing, i.e. it is consistent with prices rising.

A hypothetical numerical example is helpful. Suppose a utility initially has 10,000 customers and collects $300 per customer, so that its net revenue is $3 million. It then loses

one percent of its residential customer base, i.e. 100 customers. If prices didn't change, net revenue would be $2.97 million. But according to the estimates in Table 4, the utility's residential net revenue would decrease by 0.5 percent, leaving it with a net revenue of $2.985 million. This translates into $301.5 per customer – rates on the remaining customers have risen by 0.5 percent. We further explore this under future potential scenarios below.

4.4 Robustness Checks and Additional Specifications

In the Appendix, we show a large number of robustness checks and additional specifications, ultimately conclude that our results on the impacts of a changing customer base on pipeline miles and on net revenue collected are robust.

Results for the impact of customer base changes on pipeline miles are shown in Table A3. We include utilities with a large fraction of retail choice customers; this adds around 300 observations but essentially does not change the point estimates. We next include large year-on-year customer changes that likely indicate mergers, acquisitions, etc.

We next include one-year periods of growth or loss. This has the greatest impact on our observation count of any robustness check – in the raw data, many utility-year observations are one-year blips in either customer growth or customer loss. This is especially true because we drop the observations that experience such a blip in *either* the residential or the commercial sector. The robustness check that includes these one-year periods yields qualitatively similar coefficients and conclusions. Most importantly, the asymmetry we see in customer growth or loss is still notable in this robustness check. The coefficient on residential customer growth is somewhat smaller, which is intuitive if pipeline miles do not need to grow in response to one-year blips that do not represent sustained customer growth.

We include utilities with small mile counts, which somewhat attenuates the coefficient on growing miles but does not change our conclusions about asymmetry.[20] We next include large changes in miles that may indicate measurement error. Alternatively, we use a more

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[20]This is explored in greater depth in Table A4.

stringent definition of outliers in this variable.

We next limit the sample just to investor-owned utilities, dropping municipal utilities. Alternatively, we limit the sample to medium and large utilities, i.e. those with at least 10,000 residential customers in every year. Next we include the additional weather and quantity-per-customer controls that we include in the net revenue specifications. Next we add either year effects or fixed effects, while still estimating the regression in differences.

Across all of these additional specifications, we continue to find an asymmetric impact of customer base changes on miles. The coefficient on residential customer growth ranges from 0.18 to 0.46, and all specifications have comparable statistical significance. The impact of customer loss is generally close to zero. The one exception is the specification that limits the sample to investor-owned utilities. For that specification, we are unable to precisely estimate the impact of residential customer loss. This is intuitive, given that 73 percent of observations for investor-owned utilities have increasing residential customer counts (Table 2).

We similarly estimate several additional specifications for the net revenue variable, concluding that our main results are robust (Tables A6 and A7). We estimate regressions using alternative samples as we did for the miles specification (e.g., including retail choice, limiting to investor-owned utilities, etc.). In addition, we include a specification that has both residential and commercial counts on the right-hand side; a specification with an alternative net revenue measurement; and a specification that limits the sample to just those utilities for which we observe pipeline miles. Across this broad suite of robustness checks, we continue to estimate a coefficient close to 1 when residential customer count is growing and a coefficient of around 0.5 when the residential customer count is shrinking. As with the miles specification, we lose power on the shrinking coefficient when we limit to investor-owned utilities; we also lose power when we limit to large utilities, or when we add fixed effects (akin, in this differences specification, to utility-specific trends). Commercial results are similarly robust across these additional specifications.

To summarize, we show that growing utilities add new pipeline infrastructure, but utilities with shrinking customer bases continue to maintain the same amount of legacy pipeline infrastructure. In keeping with this, utility revenues rise (with an elasticity of one) when the customer base grows, but shrink by an asymmetric amount when the customer base shrinks. That is, prices for remaining customers rise. We next turn to a discussion of the implications for equity across customers as well as an examination of utility expenditures.

5 Discussion and Policy Implications

5.1 Income and Racial Equity

Rising prices for remaining customers at a shrinking utility will clearly have equity implications. This is true both historically, for the customer base shrinking that we observe in our sample, and in the future, for example, with customers leaving the utility following building electrification. As customers leave natural gas service, they stop paying for the pipeline infrastructure that they leave behind. How this interacts with income, racial, or other inequality depends on the characteristics of the customers who leave, as well as on the characteristics of the customers who get left behind. Unfortunately, our data does not allow us to explore this in depth. Ideally, one would observe the demographic and socioeconomic characteristics of each customer, which our data do not provide.[21]

However, we are able to provide suggestive evidence of inequality, particularly along racial lines, induced by the customer net migration that we have documented. In Table 5, we list the eight utilities which experienced the largest loss in residential customers from 1997 to 2019. The table also reports the eight utilities which experienced the largest increase in residential customers. These sixteen utilities are generally large utilities (almost all have more than 100,000 residential customers at the beginning of our sample, and the largest

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[21]Moreover, as described above, our HIFILD data on service territories are only a single snapshot, not a panel.

Table 5: Demographic Characteristics of Shrinking and Growing Utilities

State	Utility	Initial Residential Count	Change	Largest City Served	Poverty Rate	Pop. Change 2000-19	Percent Black or Afr-Am.	Income Per Cap. $000's
Panel A: Utilities with largest customer loss:								
AL	Alabama Gas Corp	423,130	-29,865	Birmingham	26	-13	70	24
AR	Centerpoint Energy Arkla	386,572	-25,949	Little Rock	17	8	42	36
AL	Spire Gulf Inc	95,021	-16,279	Mobile	21	-7	52	27
OK	Centerpoint Energy Arkla	100,850	-13,385	Lawton	19	0	20	24
PA	Philadelphia Gas Works	492,945	-10,100	Philadelphia	24	5	42	28
WV	Hope Gas Inc	111,216	-9,553	Charleston	21	-13	16	35
LA	Centerpoint Energy Entex	116,781	-9,085	Shreveport	26	-6	57	26
GA	Albany Wtr Gas Lt Comm	16,298	-5,864	Albany	31	-7	74	20
Panel B: Utilities with largest customer gain:								
IL	Nicor Gas	1,722,299	342,511	Aurora	11	37	10	31
NV	Southwest Gas Corporation	337,465	393,567	Las Vegas	15	35	12	31
UT	Questar Gas Company	560,717	411,496	Salt Lake City	17	10	3	37
CO	Pub Service Co Of Colorado	889,902	419,749	Denver	13	31	9	44
AZ	Southwest Gas Corporation	598,050	453,019	Phoenix	18	27	7	29
TX	Centerpoint Energy Entex	1,103,814	545,829	Houston	20	18	23	33
CA	Pacific Gas	3,493,097	791,719	San Jose	9	13	3	47
CA	Southern California Gas	4,599,840	1,007,849	Los Angeles	18	8	9	35

Note: This table describes the eight natural gas utilities in our sample which experienced the largest loss in residential customers along with the eight utilities which experienced the largest gain in residential customers from 1997 to 2019. The last four columns provide demographic statistics from the U.S. Census Bureau for the largest city served by each utility.

serves more than 4 million residential accounts). They are generally investor-owned utilities, with the exception of the municipally-operated Philadelphia Gas Works and a municipal utility in Albany, Georgia. And, they generally experienced *prolonged* periods of either growth or loss over our time period, as opposed to one-time changes (Appendix Figure A2).

For each utility, we list the largest city served, according to the utility's website. Again, we do not have comprehensive information on service territories across time, but it is straightforward to find information on the largest cities served. We then list four demographic characteristics for each city: the poverty rate, the population change over the 2000-2019 period, the percentage of the city's population that is Black or African-American, and the annual per capita income (in thousands of dollars).[22]

Several striking things emerge from Table 5. First, the utilities with the largest customer losses generally serve cities with declining or flat populations. Several cities experienced

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[22]The socioeconomic variables are reported at the city level by the Census Bureau using data from the American Community Survey five-year estimates; we report vintage year 2019 estimates.

large losses in population: Birmingham, Alabama and Charleston, West Virginia, each with a drop of 13 percent; also Mobile, Alabama; Albany, Georgia; and Shreveport, Louisiana. In contrast, the utilities with the largest customer gains generally served cities with growing populations: Aurora, Illinois experienced a staggering 37 percent increase in population and Las Vegas 35 percent. The growing utilities nearly all serve states in the West and Southwest, consistent with regional demographic trends in the U.S. over this time period.

Second, the utilities with large customer losses overwhelmingly serve cities with large African-American populations. With the exceptions of Charleston, WV and Lawton, OK, the largest cities served by the shrinking utilities have populations that are 40 percent or more African-American. In contrast, the utilities with growing customer bases generally serve cities with much smaller African-American populations. A number of economic and social forces may be at play here; Beauregard (2009) identifies several factors responsible for shrinking cities over the 1980-2000 period, including suburbanization, racial antagonisms, and more. For instance, one important force behind migration in the U.S. has been White flight and suburbanization, the latter frequently racially restricted. While most work has emphasized the post-War period, Crowder and South (2008) and Beauregard (2009) suggest this legacy continues in more recent decades. Future work could look at whether historical White flight has led to a stranded pipeline infrastructure that must be maintained by the remaining African-American population.

Table 5 also shows a pattern of income inequality that is correlated with shrinking or growing customer bases. The median poverty rate in the large cities served by shrinking utilities is 23, and the median rate for the growing utilities is 16. Similarly, the median per-capita income in the shrinking sample is $27,000, compared to $34,000 in the growing utilities. This pattern matches that explored by Faust, Abraham and McElmurry (2016), who examine water infrastructure management in four shrinking cities. They focus on the Rust Belt and not the South, but like us, show that the shrinking cities have low incomes, and therefore "shrinking cities face not only a decline in [water] customers but also the inability

of the existing customers to afford drastically increasing rates" (p. 133). The pattern is also consistent with the vicious cycle of urban economic decline described by both Faust, Abraham and McElmurry (2016) and Galster (2017); the latter writes that "selective outflow renders the city increasingly occupied by the disadvantaged," noting also that "[o]ut-mobility of disadvantaged households who are African-American or Latino may be further constrained by illegal discrimination in housing markets outside of declining cities" (p. 357).

The evidence on mostly larger, mostly urban utilities in Table 5 complements the evidence shown earlier on declining residential customer counts for municipal utilities (Table 1). This customer base loss for municipalities is intuitive given the rural depopulation of much of the United States. As Johnson and Lichter (2019) write, "[p]opulation loss has seemingly become the new demographic norm across broad regions of rural America" (p 4).

Overall, we highlight three equity-related implications of our work. All three are suggestive, but future work could explore these on a national scale. First, we show patterns of customer base loss in predominantly African-American cities, which may contribute to higher energy bills for urban African-American populations. Second, rural depopulation may also lead to rural/suburban divide in energy bills and infrastructure quality. Finally, if future electrification leads to inequality in energy expenditures (an issue we next explore in depth), it may be worth investigating how these future issues interact with the past inequities described above.

5.2 Simulating Building Electrification

As we discuss above, building electrification is emerging as a central policy issue for climate change mitigation. Our results point to a thorny issue during a transition period in which some, but not all, buildings electrify. If building electrification occurs in a geographically dispersed manner, utilities will need to maintain legacy pipeline networks but will have fewer customers to pay for this maintenance. As we show above, shrinking customer bases lead to rising prices for remaining customers, with implications for equity. In this section, we explore

potential price impacts in greater detail. We focus on the residential sector, for which the equity implications are clearest, but we note that similar mechanisms are at play in the commercial sector. We assume throughout this analysis that there is no cross-subsidization across sectors, i.e. the revenue requirement in the residential sector does not depend on what occurs in the commercial sector, consistent with traditional utility practice.

In Figure 4 we plot (middle black line) the implications of the estimates from Table 4 for a rise in prices under different magnitudes of natural gas customer exit. Specifically, in a scenario in which zero percent of residential natural gas customers exit, we assume the typical customer pays $328 per year in net revenue.[23] Then we assume that each one percent of lost gas customers leads to a 0.53 rise in prices for everyone else, based on our estimates in Table 4.[24]

As Figure 4 shows, this percentage rise in bills is fairly small when only a few customers exit the natural gas sector, but bills can rise a substantial amount if many customers exit. To see this, imagine that all customers but one exit, and that remaining customer must cover all of the utility's legacy costs. Recent papers on economy-wide decarbonization assume a fairly rapid transition to residential building electrification. The papers assume something on the order of a 15 percent reduction in natural gas residential customers by 2030; 40 percent by 2040; and 90 percent reduction by 2050 (Aas et al., 2020; Larson et al., 2020; National Academies of Sciences, Engineering, and Medicine, 2021; Williams et al., 2021). Our estimates imply that customer exit of this level this would translate into annual bill increases of $31, $116, and $1,565 per customer, respectively.

This general pattern is similar to previous calculations by policy analysts. Gridworks (2019) calculates a roughly 100 percent increase in residential natural gas bills for a 60 percent decrease in residential gas demand in California (although note that figure includes gas commodity costs, which we have not included). As another point of comparison, a CEC

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[23]$328 is our estimate for net revenue at growing utilities in Table 4; it is also similar to the median residential net revenue value of $350 in Table 1.

[24]Recall that in Table 4, 47 log points of net revenue are lost, leaving 53 log points for other customers.

Figure 4: Utility Bills Rise Non-Linearly With Customer Exit
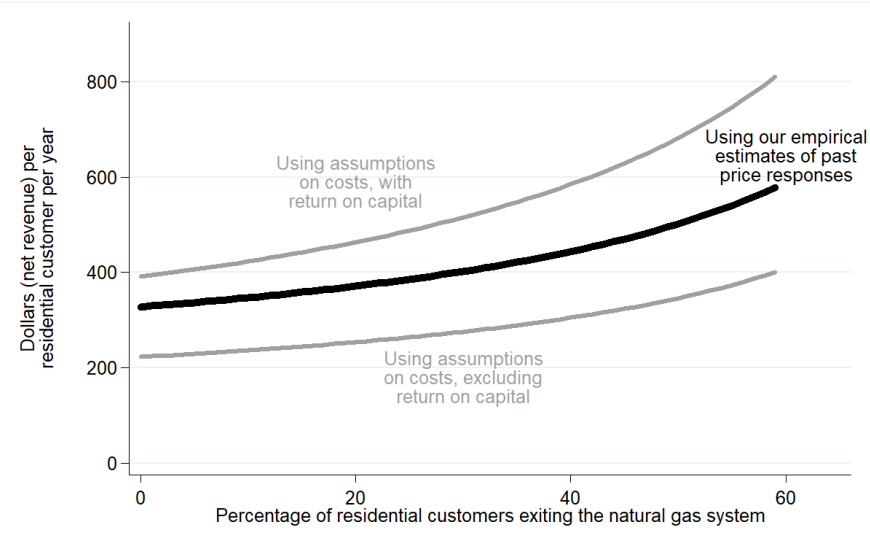
Note: This figure plots how the net revenue per residential customer (that is, bill totals net of gas costs) changes as other customers exit, for instance because they switch to electric heating and cooking. The middle black line uses empirical estimates from past utility behavior, specifically the estimates in Table 4. The top and bottom lines use assumptions about fixed versus marginal costs based on financial data from a representative sample of utilities, as explained in Section 5.3. Note that if gas costs were included, it would simply shift all three lines up by a constant amount, equal to around $300 per customer per year (Table 6) but fluctuating with weather and macroeconomic conditions.

analysis (Aas et al., 2020) describes a scenario in which rates increase by 80 percent by 2030 and 480 percent by 2050, although that includes other cost drivers too. Of course, the previous analysis assumes that the cost structure in the future for a typical utility can be inferred from our empirical analysis of past customer losses. To better understand how the impact of future electrification might differ from the past impact of customer base loss, and to inform potential policy options, we next examine data on expenditure patterns at U.S. natural gas utilities and discuss how different categories of expenditure might change with widespread building electrification.

5.3 Utility Expenditures

In this section we turn to financial data from an ancillary data source in order to provide additional details about the different categories of utility expenditures. The American Gas Association, a large trade organization, conducts an annual benchmarking survey of around 80 natural gas distribution utilities. The utilities represented are a mix of investor-owned and municipal utilities. They are not a random sample, but together they represent a substantial portion (around 70 percent) of all customers nationwide. Details on this AGA report, and the calculations we make using it, are in the Appendix.

In Table 6, we describe the expenditures of a typical natural gas distribution utility. Perhaps not surprisingly, the single largest expenditure is purchasing natural gas (over $300 per residential customer per year). Recall that our previous analysis netted out this expenditure to focus on fixed costs related to pipelines.

The second largest expenditure for a typical utility (around $170 per residential customer per year) is for past capital expenditures. The largest capital expenditures are main and service pipelines, but examples of smaller categories are compressor station equipment, building structures, tools, and trucks. The capital expenditures category is composed of both annual write-downs of past capital (that is, depreciation) – around $63 per residential customer per year – and a payment to investors for their return on past capital expenditures (around $105). At any given utility, this amount will depend on depreciation to date as well as the rate of return allowed by utility regulators. These first two categories, expenditures for natural gas and capital expenditures, together account for about two-thirds of total utility expenditures.

The remaining one-third consists of operating expenditures and taxes. The next category ($85 per residential customer per year) is administrative expenses, including salaries to executives, pension payments, etc. Distribution operations and maintenance (averaging around $66 per residential customer annually) refers to labor and materials for operating and maintaining the distribution network (pipelines as well as customer meters).

Table 6: Expenditure Categories for U.S. Natural Gas Distribution Utilities

Category	Examples	Average dollars per customer annually	Assumed portion leaving with the customer
Gas cost	Cost of purchasing natural gas	$312	1.0
Capital-related expenditures:			
Depreciation	Annual write-down of past capital expenditures	$63	0.0
Return on net utility plant	Return for investors on past capital expenditures	$105	0.0
Operations-related expenditures:			
Administrative	Admin salaries, outside services, pensions, injuries and damages, customer assistance, advertising	$85	0.5
Distribution operations & maintenance	Maintenance of distribution mains, service lines, and meters	$66	0.1
Accounts	Meter reading, customer records, and uncollectibles	$25	0.9
Taxes	Sales, income, property, etc.	$47	0.6

Note: This table was constructed by the authors based on financial data from the American Gas Association's "2016-2018 Performance Benchmarks for Natural Gas Utilities" report EA 2020-03. The last column shows the assumptions we make regarding what portion of the category's expenditures are eliminated when a customer leaves; for instance, a utility no longer needs to purchase any gas for that customer (first row), but must still recover all of its past capital expenditures (second and third rows). Details on the AGA report and on the assumed portion column are in the Appendix.

Finally, utilities have expenditures related to servicing accounts ($25 per residential customer per year), which includes meter reading but also expenses related to nonpayment. We note that a recent report (Aas et al., 2020) focused specifically on California utilities reports a similar breakdown of expenditures across capital, operations, and taxes to what we describe in Table 6.

The last column of Table 6 shows our assumptions about how each of these categories of expenditure change in response to customer base loss. While it would be have been interesting to instead try to infer these measures empirically, data limitations prevent a comprehensive analysis of this sort. The AGA data are available only at the aggregate level, not for individual utilities. Moreover, even if it were somehow possible to access the underlying microdata, the set of utilities surveyed and data collection methodology changes across years, making these data poorly-suited for comparisons across years.

Still, we think that introspection provides strong guidance on how most of these categories should be expected to change as customers leave the natural gas system (Table 6, right-most column). First, we assume that 100 percent of expenditures on natural gas are eliminated when a customer exits. The utility no longer needs to procure natural gas on that customer's behalf so these costs are clearly marginal to the customer. Second, we assume that 0 percent of capital expenditures are eliminated when a customer exits, reflecting the fact that these are a sunk cost that must still be recovered even when a customer exits.

Third, we assume that between 10 percent and 90 percent of operating expenses are eliminated when a customer exits, with the exact percentage varying across categories. We assume that half of administrative expenses are eliminated but half are not. Pensions, for instance, must still be paid when a customer exits. However, expenditures on customer assistance can presumably decrease as there are fewer customers to assist. In contrast, we assume that almost none of the distribution operations and maintenance expenditures are eliminated – since the pipeline network has not changed, the same amount of maintenance must be conducted for safety to not be compromised. We assume some are eliminated because, for instance, the departing customer's meter may no longer need the same maintenance. We assume that most customer-related account expenditures are eliminated, as a meter reader is no longer needed for that household. We assume that not all of these expenses are eliminated since, for instance, a utility without internet-connected meters must still send a person down the street to read nearby meters of remaining customers, so the cost of meter reading does not decrease one-for-one in some cases. For taxes, we use the weighted average portion from the other categories.

In Figure 4, we plot how net revenues vary across different customer exit rates according to these assumptions on expenditures. We plot two different sets of net revenue changes. The upper grey line includes the capital costs described above. The lower grey line excludes this category of expenditures. We plot this second line for two reasons. First, our historical look-back at customer base exit, driven by demographic changes in the U.S., may be reflecting

utilities that already depreciated most or all of their capital costs and are no longer paying out a return to investors. Utilities that have experienced years of customer base loss presumably have had minimal new infrastructure projects. Second, going forward, utilities may choose not to build new pipelines if they expect a high degree of building electrification, such that eventually they would not be recovering capital costs from their customers. In the interim, we might expect a price path between these grey lines.

Our estimates based on expenditure categories and assumptions about what portion of costs are eliminated when a customer exits yields price paths in Figure 4 that are remarkably similar to the path we construct using our empirical estimates. Indeed, the assumptions with and without capital returns could be thought of as bounding cases for our empirical estimates, which average across utilities at different points in depreciation schedules. Also, the similarity in price paths provides some reassurance that our empirical estimates are broadly representative, even though the utilities that experienced customer losses during our sample period tend to be municipally-owned, smaller, and rural.

Probably the most important take-away from this analysis of utility expenditures is that a considerable portion of capital and operating expenses are not eliminated by customer exit. This is consistent with our empirical analysis of net revenue, and it implies that under electrification scenarios with a growing number of households discontinuing natural gas service, remaining natural gas customers can expect rising bills.

5.4 Alternative Utility Financing Options

Researchers, environmental groups, and government agencies have proposed a number of potential policies to manage utility financing and equity issues during a transition away from residential natural gas (Bilich, Colvin and O'Connor, 2019; Greenlining Institute, 2019; Gridworks, 2019; Mahone et al., 2019; Aas et al., 2020; Larson et al., 2020; National Academies of Sciences, Engineering, and Medicine, 2021; Williams et al., 2021). These white papers have examined a suite of potential policies – suggesting that no single silver bullet policy

will ensure an equitable and cost-effective transition. In this section, we discuss what our results say about how these various policies might fare. The main takeaway from our empirical analysis is that as residential customers exit natural gas service, this increases bills for customers left behind. Our empirical estimates imply, for example, that when 15 percent of residential customers exit, this increases bills by \$30 per year for customers left behind. These bill increases have important implications for efficiency as well as equity, and we show that there has tended historically to be a pronounced pattern in which these remaining customers disproportionately tend to come from disadvantaged groups. In this section we discuss alternative options for utility financing that could break this historical pattern, and what these alternatives could mean for efficiency and equity.

5.4.1 Changing the Composition of Customer Exit

One type of policy intervention would be to subsidize building electrification for low-income households or other disadvantaged groups, thereby changing the composition of customer exit (and perhaps accelerating overall electrification). However, simply funding low-income electrification projects will leave high rates for remaining users, which may prove burdensome for low and middle income customers who do not enroll in the program. Some of these customers may prefer natural gas over electricity (Davis, 2021); may fail to qualify if they are middle-income (Forrester and Reames, 2020); or may have trouble accessing the program (Fowlie, Greenstone and Wolfram, 2015; Raissi and Reames, 2020). In addition, such a policy by itself would not solve the underlying financial difficulties of the natural gas utility.

Targeted electrification has been suggested as one way to reduce ongoing operations and maintenance costs; in this scenario, whole areas are electrified so that pipelines can be shut down. One could imagine targeting based on safety and climate goals, particularly in areas where aging pipelines would otherwise be *replaced* – incurring capital costs that would need to be paid by future customers. Such a targeted electrification policy could lead to a more equitable or a less equitable transition, depending on which areas are targeted. Of course,

this policy alone does not solve the historical capital costs problem.

5.4.2 Changing How Utility Customers Pay

With regard to the utility's ability to recover its fixed costs, one alternative would be to accelerate the depreciation schedules used by utility commissions in rate-making. Accelerated depreciation allows the utility to recover capital costs more quickly, meaning that these legacy costs are around for fewer years, and thus potentially also reducing financing costs. This approach does not address the problem of ongoing maintenance costs associated with sparsely used pipelines; as we show above, these are not trivial. Other limitations of accelerated depreciation include that it will, in the short term, raise prices for remaining customers even further.

A few other policies more directly target the underlying incentive problems. Fundamentally, utility financing relies on a stable or growing customer base to recover past costs; in this way, incentives for customer entry and exit are not correctly aligned. One could imagine pricing schemes that correctly align incentives for customer entry and exit. For instance, customers could pay hook-up fees that cover the future stream of capital and operations and maintenance costs, so that if they later exit, they are not leaving remaining customers on the hook. This, however, faces two challenges. First, utilities have generally wanted to grow their customer base to bring in new sources of revenue, and a high connection fee disincentivizes future growth. It's worth noting that the discussion around widespread customer loss is relatively new – as recently as 2013, some states were instead investigating policy issues related to natural gas distribution *extensions*, because of low commodity prices induced by fracking. Costello (2013) discusses rate-setting principles in this setting, for instance "growth should pay for itself by requiring new customers to pay the full costs for extending service to their areas" – but does not consider how this principle might account for the potential *exit* of customers in the future. This kind of policy may face pushback from ratepayer advocates, for whom access to energy is viewed as a fundamental human right.

A closely related alternative would be to charge exit fees. That is, customers departing the system would be asked to cover a portion of the capital and operations and maintenance costs they leave behind. Our empirical analysis implies that exit fees would need to be quite large – in excess of $1000 per household – if they were to completely cover the present discounted value of legacy costs. Such a solution could be very effective at reducing cost shifts, but is likely to be politically and logistically challenging, and would, of course, be highly unpopular with customers who would correctly claim that they were not warned about such fees when they initially signed up for natural gas service. In addition to these substantial obstacles, exit fees would delay the transition of households away from on-site consumption of fossil fuels.

Customers of *electric* utilities could instead cover the transition costs associated with the electrification transition. How this is structured would depend on whether the same utility serves gas and electric customers, and if not, on the way in which each utility is regulated. In the United States about two-thirds of natural gas distribution utilities are "single-fuel" and sell only natural gas while about one-third are "dual-fuel" utilities that sell both natural gas and electricity (Knittel, 2003). An interesting question moving forward is whether dual-fuel utilities might begin cross-subsidizing natural gas customers by increased revenue collection from electricity customers. This type of cross-subsidization has not been widely done historically and tends to go against the utility ethos of "cost allocation." In addition, electricity rates already include considerable fixed costs of their own, resulting in a price per unit of electricity that exceeds social marginal cost in most parts of the United States (Borenstein and Bushnell, 2021).

5.4.3 Moving Costs Away from Utility Customers

Finally, utility fixed costs could be recovered through the general tax base rather than from utility customers. Indeed, this is done for other natural monopolies, such as the postal service. It has also been proposed for electric utilities facing declining cost recovery because

39

of residential rooftop solar adoption (Borenstein, Fowlie and Sallee, 2021).[25] A variant on this would use cap and trade or carbon tax revenues, rather than the general tax base.[26] The pros and cons of recovering fixed costs through the general tax base are discussed in Viscusi, Vernon and Harrington (2005) – particularly, political economy questions and incentives to control costs. However, this canonical text does not cover in depth the dynamic issues around customer entry and exit. In particular, we note that recovery via the tax base can have the advantage of decoupling fixed cost recovery from net migration.

To summarize, a number of policies have been suggested. Our results can contribute to these discussions in a number of ways. First, by recognizing that the transition difficulties associated with electrification are fundamentally a result of the way that natural monopolies in the U.S. recover their fixed costs, proposals that address the underlying issue can be crafted. Second, we point out that there are multiple issues to be addressed, and as such multiple policies may be needed: capital cost recovery; ongoing maintenance cost recovery; and equity issues. Fully addressing all of these will likely require a combination of policies. Finally, researchers and policymakers may be able to learn from successful policies used in other domains (natural gas, electricity, water, transportation), since the underlying market structure is similar and the underlying economic issues nearly the same.

6 Conclusion

The utility business is often thought of as stable, predictable, or even boring. But we show that U.S. natural gas utilities have experienced a surprisingly large amount of recent change, with many utilities consistently gaining customers while other utilities consistently lost customers over our sample period, 1997-2019. Our paper exploits these changes to test

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[25]Beecher (2020) also discusses the possibility of funding fixed costs via local property taxes, arguing that it may be less regressive than current rate structures (although note that local taxes would not decouple cost recovery from migration impacts).

[26]Such a policy has been proposed for low-income energy assistance; see Fowlie, Meredith. "California's Billion Dollar Energy Bill Question" Energy Institute Blog, UC Berkeley, April 5, 2021, `https://energyathaas.wordpress.com/2021/04/05/californias-billion-dollar-energy-bill-question/`.

how utility operations and finances evolve during growth and loss. We show that utilities expand the distribution network during years of customer growth but rarely shrink the network during periods of customer loss. Moreover, we find that utility revenues increase one-for-one during years of growth, but decrease by only half as much during years of loss, implying that remaining customers make up the difference through increased rates.

These dynamics have important implications for a growing set of policies aimed at transitioning households and firms away from natural gas toward electricity. We show that during our sample period the utilities experiencing customer losses tended to be in cities with higher poverty rates and a higher percentage of African-American residents. Future energy transitions will not follow the exact same pattern, but our results nonetheless highlight the potential for bill impacts to be distributed across households in ways that are uneven and often exacerbate existing societal inequalities. In addition, we use simulation evidence and ancillary data on typical expenditures for U.S. natural gas utilities to show the large potential magnitude of bill impacts. Based on our empirical estimates, for example, we show that bills can be expected to increase by more than $115 dollars per year in response to 40 percent of residential customers exiting the system. In our calculations, residential bills increase non-linearly, with the last few customers covering the fixed costs of everyone that exited before them.

These dynamics also have major implications for efficiency. A central theme in energy economics is the importance of pricing energy efficiently (Borenstein and Bushnell, 2021). Putting more fixed costs into retail prices threatens to increase deadweight loss for remaining customers. At the same time, higher retail prices for natural gas will also accelerate the transition away from natural gas, prompting further exits, and thus additional price increases, in the natural gas version of the "utility death spiral." While these dynamics will not last forever, an energy transition of this magnitude affects a large number of U.S. households and businesses, so it is critical to trace out the implications for both efficiency and equity.

Finally, it is worth highlighting that this issue of legacy utility costs is not unique to this

particular sector. While our analysis focuses on natural gas distribution utilities, customer exit raises similar challenges for funding natural gas pipeline infrastructure. As the amount of gas flowing through intra- and interstate pipelines decreases, the fixed costs associated with these investments are spread over a smaller number of customers. The extent to which this occurs in the future depends not just on what happens with building electrification, but also whether a transition away from natural gas occurs in the industrial and electric power sectors. More generally, our work highlights a broader dynamic which can occur in many sectors with large fixed costs including public transportation, mail delivery, and traditional telephone service.

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A1 Appendix

A1.1 Data Appendix

A1.1.1 Company Type

As we describe in the main text, the EIA data on utility ownership type appear to have some error. For instance, some utilities fail to report their type in some years. Other utilities report different types in different years. For instance, "ABBYVILLE CITY OF" typically reports that it is a municipal utility, but in 2002, 2003, 2007, and 2009, it reports no type; and in 2004 it reports that it is both an investor-owned and a municipal utility.

We first take the modal ownership structure across years for each utility. We then investigate and correct some anomalies, such as designating as municipally-run a few utilities with "City of" in their name – after verifying the ownership structure on the utilities' website. We also verify, where possible, the ownership structure on utility websites for utilities with incomplete reporting. We are unable to identify the ownership structure for a little less than three percent of utilities representing fewer than 0.1 percent of total residential customers. These are generally very small utilities without websites, and we group them in with the municipal utilities category.

We drop all observations from EIA-176 that report no residential volume sold and no residential customers. These tend to be interstate transmission companies, such as the "ALGONQUIN GAS TRANSMISSION COMPANY."

A1.1.2 Examining Large Changes in Customer Counts

Figure A1 shows examples of how we handle large year-on-year changes in customer counts, which may indicate service territory changes or may indicate measurement error.

Figure A1: Examining Large Changes
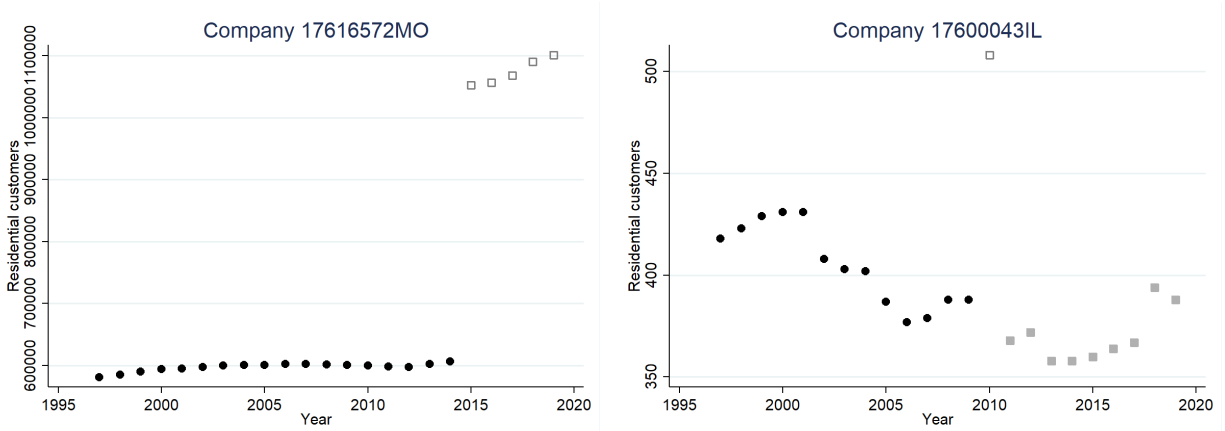
Note: This figure shows examples of companies with 20% changes in customer counts from one year to the next. In our specifications estimated in differences, we drop the these large changes; this is analogous to assigning separate company identification numbers whenever a firm's residential customer count changes by more than 20 percent. Sometimes that appears to be because of service territory changes (left panel) and sometimes potentially data entry error (right panel). In the left-hand panel, we drop the 2014 to 2015 change. In the right-hand panel, we drop the 2009 to 2010 change and the 2010 to 2011 change.

A1.1.3   Merging EIA and PHMSA Data

To merge the EIA and PHMSA data, we use a fuzzy string match (Stata's reclink command) on company names and an exact match on the state within which the company operates. EIA reports the same company name across all years. The PHMSA dataset lists year-by-year company names, reflecting both actual name changes and also different abbreviations across years. We merge on the most recent name (2019) for the majority of matches. For firms that fail to match, we evaluate by hand whether an earlier name appears in the PHMSA data that matches to an EIA name. For instance, EIA reports a firm called "NICOR GAS" and PHMSA lists a firm in some years as "NICOR GAS" and in some years as "NORTHERN ILLINOIS GAS CO." We also evaluate by hand failed matches that can be fixed with different abbreviations. For instance, EIA reports a Maryland firm called "BGE" and PHMSA lists a Maryland firm called "BALTIMORE GAS AND ELECTRIC COMPANY."

We are ultimately able to match 83 percent of the EIA observations to PHMSA data (representing 87 percent of residential customers). Of the remaining observations, some represent company-year combinations for which no data appear in PHMSA. Other failed

EIA to PHMSA matches represent company-year combinations for which there are multiple service territories reported separately in either EIA or PHMSA and no clear matching across the two datasets. Other failed matches represent very small utilities, for instance with fewer than 100 customers. We also spot-check to verify that matches represent true matches. We verify that all regressions using the full EIA dataset yield similar results when estimated using only the companies that also appear in PHMSA.

A1.1.4   Expenditures Data

The dollar values per customer in Table 6 are calculated from the American Gas Association's "2016-2018 Performance Benchmarks for Natural Gas Utilities" report EA 2020-03.

The AGA reports dollars per customer of any type rather than dollars per residential customer, so we scale all values by 0.7 – the ratio of the typical residential bill to the typical bill of any customer type in our sample.

We use the median 2018 values from the AGA report's Appendix 3d for depreciation and taxes. Note the depreciation amount is roughly equal to 3.4 percent of the net utility plant per customer reported by AGA; i.e. what would be expected from a 30-year straight-line depreciation schedule. For return on net utility plant, we use "total operating income" in Appendix 3d; note this is roughly comparable to a six percent return on net utility plant, using net utility plant (e.g. minus accumulated depreciation) from Appendix 3b and gas plant per customer from Appendix 3e.

We use the 2018 operations-related expenditures from the AGA report's Appendix 4. For gas cost, we use "total production costs," which are primarily purchased gas expenses. The "Administrative" category includes not only "Administrative Expenses" as defined in the AGA report, but also "Customer Svc. & Info." and "Sales" [Advertising].

In the AGA report, operations and maintenance expenses for transmission pipelines and underground storage are included in two separate categories and are generally very small ($4 per customer per year, combining across the two categories). Examples of these ex-

penditures include maintenance of storage facilities, transmission pipelines, and compressor stations. This low average reflects the fact that at many of the surveyed utilities reported that they do not have any transmission expenditures, whereas some of the larger utilities have transmission expenditures equal to or greater than their distribution-related expenditures.[27] In Table 6, we have included these two expenditures types in the "Distribution operations & maintenance" category. The examples of expenditures within each category are taken from the Uniform System of Accounts.

A1.2 Additional Tables and Figures

This section contains additional tables and figures referenced in the text, including summary statistics, robustness checks, etc.

Figure A2: Utilities with largest growth and largest loss
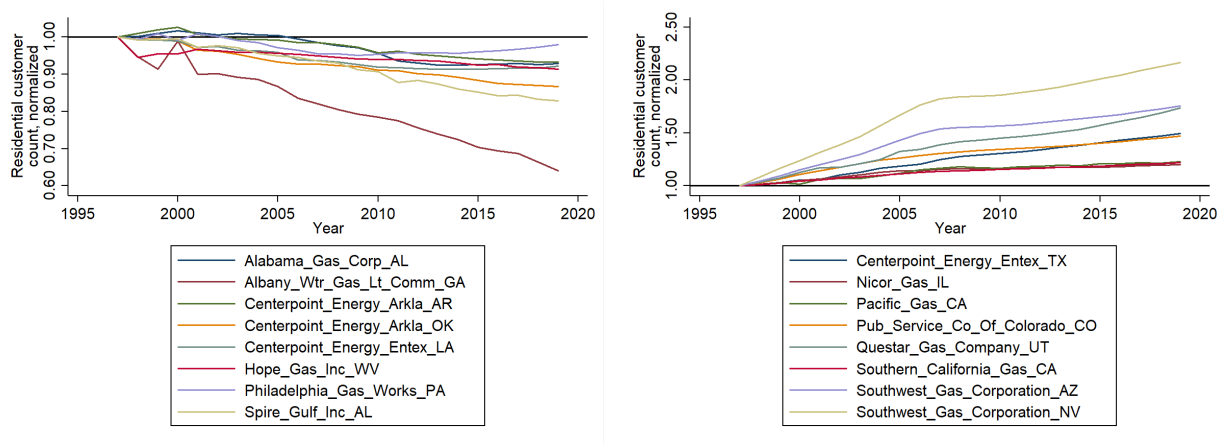
Note: This figure shows residential customer counts for the sixteen utilities displayed in Table 5 in the main text, with each utility's count normalized to one in 1997.

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[27] The AGA does not report this distribution across utilities, but we examine it with a second dataset of proprietary data from S&P, which pulls utility financials from state-level regulatory filings.

Figure A3: The Distribution of the Log Change in Miles
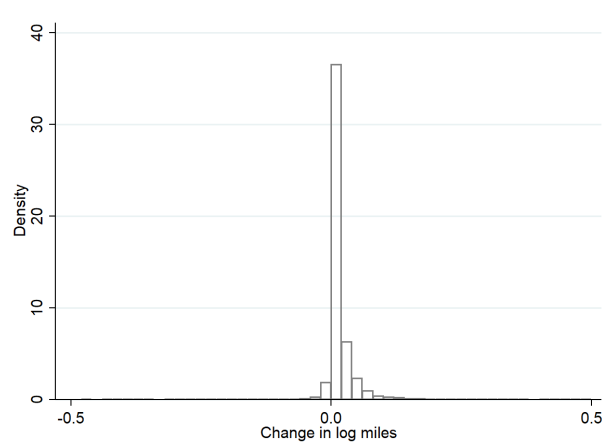
Note: This figure shows a histogram of the log annual
change in miles for our main sample.

Figure A4: The Asymmetric Relationship Between Net Revenue and Customers
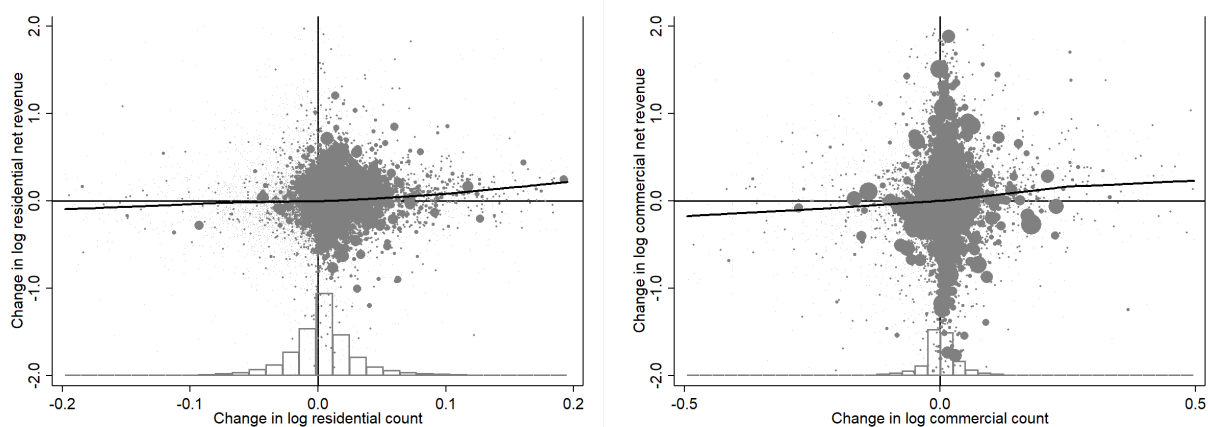
Note: This figure is analogous to Figure 3 in the main text, but for customer counts rather than miles.

Table A1: What Types of Utilities are Growing (Commercial Customer Counts)?

	N	Portion Growing
All utility-years	24,128	0.49
By ownership type:		
IOUs	6,004	0.64
Munis	18,124	0.44
By size in first year:		
1 million or more	152	0.67
100,000 − 1 million	1,799	0.72
10,000 − 100,000	2,657	0.70
1,000 − 10,000	8,593	0.54
100 − 1,000	10,443	0.35
1 − 100	484	0.21
By time period:		
1997–2007	10,687	0.50
2008-2019	13,441	0.48
By geographic region:		
New England (CT, MA, ME, NH, RI, VT)	495	0.76
Pacific (CA, OR, WA)	458	0.76
Mountain (AZ, CO, ID, MT, NM, NV, UT, WY)	1,208	0.66
Middle Atlantic (NJ, NY, PA)	639	0.60
East North Central (IL, IN, MI, OH, WI)	3,081	0.49
West North Central (IA, KS, MN, MO, ND, NE, SD)	4,423	0.46
East South Central (AL, KY, MS, TN)	5,430	0.48
South Atlantic (DC, DE, FL, GA, MD, NC, SC, VA, WV)	3,608	0.51
West South Central (AR, LA, OK, TX)	4,786	0.37

Note: This table is analogous to Table 2 in the main text, but describing commercial rather than residential customer count changes.

Table A2: Residential Customer Base Growth is Explained by Population Changes

	Change in Residential Customer Count
Household count change in service territory	0.82***
	(0.01)
Constant	40.47
	(805.22)
Observations	995
R^2	0.76

Note: We regress the change in residential customer counts (2000 to 2019), from our utility-level data, on the change in households residing in the service territory (2000 to 2019), using Census Bureau data on household counts and Oak Ridge National Lab data on 2017 service territories. We limit the sample to utilities with at least 90 percent bundled customers in both 2000 and 2019; this drops a small number of utilities that serve retail choice customers. Details on data sources are in the main text.

Table A3: Pipeline Infrastructure Results, Alternative Specifications

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Resi. cust. (log), growing	0.38***	0.39***	0.29***	0.30***	0.36***	0.45***	0.18***
	(0.04)	(0.04)	(0.04)	(0.03)	(0.03)	(0.07)	(0.05)
Resi. cust. (log), shrinking	-0.00	-0.01	-0.01	-0.01	-0.01	-0.00	0.01
	(0.04)	(0.04)	(0.02)	(0.03)	(0.03)	(0.04)	(0.02)
Comm. cust. (log), growing	0.03	0.03	0.01	0.02	0.02	0.06*	0.01
	(0.02)	(0.02)	(0.00)	(0.01)	(0.02)	(0.04)	(0.01)
Comm. cust. (log), shrinking	-0.01	-0.00	0.00	0.01	0.00	-0.00	0.01
	(0.02)	(0.02)	(0.00)	(0.01)	(0.01)	(0.02)	(0.01)
Observations	9,538	9,864	9,651	15,464	12,259	9,544	21,884
R^2	0.06	0.06	0.06	0.03	0.05	0.02	0.01

	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Resi. cust. (log), growing	0.40***	0.42***	0.46***	0.38***	0.36***	0.34***	0.44***
	(0.03)	(0.07)	(0.07)	(0.04)	(0.04)	(0.04)	(0.13)
Resi. cust. (log), shrinking	-0.04	0.24	-0.04	-0.00	0.01	-0.02	0.05
	(0.03)	(0.22)	(0.06)	(0.04)	(0.04)	(0.05)	(0.07)
Comm. cust. (log), growing	0.01	0.05*	-0.01	0.03	0.02	0.03	0.00
	(0.01)	(0.03)	(0.03)	(0.02)	(0.02)	(0.02)	(0.01)
Comm. cust. (log), shrinking	-0.00	0.03	0.02	-0.01	-0.00	-0.02	0.02
	(0.02)	(0.03)	(0.04)	(0.02)	(0.02)	(0.02)	(0.01)
Observations	9,523	2,887	2,681	9,500	9,538	9,538	4,086
R^2	0.09	0.07	0.04	0.06	0.06	0.19	0.11

Note: This table shows point estimates and standard errors from 14 separate least squares regressions aimed at exploring the robustness of our pipeline infrastructure results to alternative specifications. Column 1 recreates the estimates from the main specification from Table 3. Column 2 includes utilities with customer choice. Column 3 includes large year-on-year log changes that may indicate service territory changes. Column 4 includes one-year regimes. Column 5 includes utilities with small miles counts. Column 6 keeps large left-hand side changes. Column 7 combines the samples from Columns 2-6, keeping all raw data. Column 8 drops even smaller left-hand side changes (50 log points). Column 9 limits to IOUs. Column 10 limits the sample to utilities with at least 10,000 residential customers in every year. Column 11 includes weather and quantity-per-customer controls. Column 12 adds year effects. Column 13 adds fixed effects (specifications are still estimated in differences). Column 14 uses three-year differences rather than one-year differences.

Table A4: Pipeline Infrastructure, Alternative Specifications

	All	10+ miles	20+ miles	30+ miles	40+ miles
Resi. cust. (log), growing	0.36***	0.37***	0.38***	0.41***	0.42***
	(0.03)	(0.03)	(0.04)	(0.04)	(0.04)
Resi. cust. (log), shrinking	-0.01	-0.02	-0.00	-0.02	-0.04
	(0.03)	(0.03)	(0.04)	(0.04)	(0.05)
Comm. cust. (log), growing	0.02	0.02	0.03	0.01	0.00
	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)
Comm. cust. (log), shrinking	0.00	-0.00	-0.01	-0.01	-0.02
	(0.01)	(0.02)	(0.02)	(0.02)	(0.03)
Observations	12,259	11,066	9,538	8,323	7,458
R^2	0.05	0.05	0.06	0.06	0.06

Note: This table shows alternative specifications for the asymmetric pipeline results given in Table 3. The first column includes all utilities; subsequent columns drop small utilities with, e.g., less than 10 miles of pipeline.

Table A5: The Impact of Customer Base Changes on Net Revenue

	Residential	Commercial	Residential	Commercial
Customers (log)	0.65***	0.75***		
	(0.09)	(0.06)		
Customers (log), when growing			1.01***	0.86***
			(0.13)	(0.10)
Customers (log), when shrinking			0.47**	0.77***
			(0.20)	(0.11)
D.hdd	-0.00***	-0.00***	-0.00***	-0.00***
	(0.00)	(0.00)	(0.00)	(0.00)
D.cdd	-0.00**	-0.00*	-0.00**	-0.00
	(0.00)	(0.00)	(0.00)	(0.00)
D.lnresi_qpc1	0.37***		0.37***	
	(0.04)		(0.04)	
D.lncomm_qpc1		0.57***		0.57***
		(0.03)		(0.03)
resi_dummy_grow_1			-0.01**	
			(0.01)	
comm_dummy_grow_1				-0.02**
				(0.01)
Constant	0.00*	0.00*	0.00	0.01**
	(0.00)	(0.00)	(0.01)	(0.01)
Observations	14,437	14,017	14,437	14,017
R^2	0.02	0.08	0.02	0.08

Note: This table shows the coefficients for all right-hand side variables for the regression results shown in Table 4 in the main text.

Table A6: Net Revenue from the Residential Sector, Alternative Specifications

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Resi. cust. (log), grow	1.01***	1.00***	1.01***	0.93***	1.19***	0.88***	0.76***	1.25***	0.98***
	(0.13)	(0.13)	(0.10)	(0.11)	(0.18)	(0.09)	(0.11)	(0.20)	(0.18)
Resi. cust. (log), shrink	0.47**	0.47**	0.42***	0.61***	0.39	0.62***	0.53***	-0.03	-0.90
	(0.20)	(0.20)	(0.13)	(0.13)	(0.26)	(0.08)	(0.14)	(0.68)	(1.08)
Observations	14,437	14,736	14,660	24,281	14,545	27,024	14,072	4,198	3,426
R^2	0.02	0.02	0.03	0.02	0.01	0.04	0.03	0.03	0.02

	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Resi. cust. (log), grow	0.95***	1.13***	0.93***	1.01***	0.94***	1.02***	1.01***	0.99***
	(0.14)	(0.13)	(0.19)	(0.15)	(0.14)	(0.14)	(0.13)	(0.09)
Resi. cust. (log), shrink	0.33*	0.54***	0.23	0.51**	0.54***	0.50**	0.47**	0.43*
	(0.19)	(0.19)	(0.25)	(0.21)	(0.20)	(0.20)	(0.20)	(0.24)
Comm. cust. (log), grow					0.14			
					(0.09)			
Comm. cust. (log), shrink					-0.09			
					(0.10)			
Observations	14,483	14,437	14,437	12,377	14,437	14,161	14,437	5,935
R^2	0.00	0.15	0.08	0.02	0.02	0.02	0.02	0.08

Note: This table shows point estimates and standard errors from 17 separate least squares regressions aimed at exploring the robustness of our net revenue results to alternative specifications. The dependent variable in all regressions is net revenue from the residential sector, in logs. Column 1 recreates the results from Table 4, Column 3. Column 2 includes utilities with customer choice. Column 3 includes large year-on-year log changes that may indicate service territory changes. Column 4 includes one-year regimes. Column 5 keeps large left-hand side changes. Column 6 combines the samples from Columns 2-5, keeping all raw data. Column 7 drops even smaller left-hand side changes (100 log points). Column 8 limits to IOUs. Column 9 limits the sample to utilities with at least 10,000 residential customers in every year. Column 10 drops the weather and quantity-per-customer controls. Column 11 adds year effects. Column 12 adds fixed effects (specifications are still estimated in differences). Column 13 limits the sample to utilities for which we are able to merge PHMSA data. Column 14 includes both residential and commercial variables on the right-hand side. Column 15 uses an alternative net revenue measurement for utilities with retail choice customers. Column 16 uses alternative citygate price data. Column 17 uses three-year differences rather than one-year differences.

Table A7: Net Revenue from the Commercial Sector, Alternative Specifications

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Comm. cust. (log), grow	0.86***	0.86***	0.76***	0.76***	0.95***	0.87***	0.74***	1.13***	1.24***
	(0.10)	(0.10)	(0.04)	(0.07)	(0.11)	(0.04)	(0.08)	(0.15)	(0.29)
Comm. cust. (log), shrink	0.77***	0.77***	0.78***	0.68***	0.88***	0.80***	0.68***	0.90***	0.86*
	(0.11)	(0.11)	(0.06)	(0.07)	(0.14)	(0.04)	(0.09)	(0.21)	(0.51)
Observations	14,017	14,309	14,199	23,555	14,291	25,455	13,362	4,099	3,377
R^2	0.08	0.08	0.09	0.09	0.08	0.13	0.07	0.06	0.04

	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	
Comm. cust. (log), grow	0.59***	0.88***	0.84***	0.88***	0.85***	0.89***	0.86***	1.14***	
	(0.10)	(0.09)	(0.13)	(0.11)	(0.11)	(0.10)	(0.10)	(0.10)	
Comm. cust. (log), shrink	0.40***	0.78***	0.72***	0.73***	0.77***	0.76***	0.77***	0.82***	
	(0.12)	(0.11)	(0.13)	(0.13)	(0.11)	(0.11)	(0.11)	(0.15)	
Resi. cust. (log), grow					-0.04				
					(0.17)				
Resi. cust. (log), shrink					0.02				
					(0.22)				
Observations	14,055	14,017	14,017	12,017	14,017	12,771	14,017	5,715	
R^2	0.01	0.17	0.14	0.08	0.08	0.08	0.08	0.19	

Note: This table shows point estimates and standard errors from 17 separate least squares regressions aimed at exploring the robustness of our net revenue results to alternative specifications. The dependent variable in all regressions is net revenue from the commercial sector, in logs. Column 1 recreates the results from Table 4, Column 4. Column 2 includes utilities with customer choice. Column 3 includes large year-on-year log changes that may indicate service territory changes. Column 4 includes one-year regimes. Column 5 keeps large left-hand side changes. Column 6 combines the samples from Columns 2-5, keeping all raw data. Column 7 drops even smaller left-hand side changes (100 log points). Column 8 limits to IOUs. Column 9 limits the sample to utilities with at least 10,000 residential customers in every year. Column 10 drops the weather and quantity-per-customer controls. Column 11 adds year effects. Column 12 adds fixed effects (specifications are still estimated in differences). Column 13 limits the sample to utilities for which we are able to merge PHMSA data. Column 14 includes both residential and commercial variables on the right-hand side. Column 15 uses an alternative net revenue measurement for utilities with retail choice customers. Column 16 uses alternative citygate price data. Column 17 uses three-year differences rather than one-year differences.

Table A8: The Impact of Customer Base Changes on Net Revenue Per Customer

	Residential	Commercial
Customers (log), when growing	0.01	-0.14
	(0.13)	(0.10)
Customers (log), when shrinking	-0.53***	-0.23**
	(0.20)	(0.11)
Observations	14,437	14,017
R^2	0.02	0.08

Note: This table is analogous to Table 4 in the main text, but the left-hand side is net revenue per customer rather than total net revenue.

Table A9: The Impact of Customer Base Changes on Quantity Per Customer

	Residential	Commercial
Customers (log), when growing	-0.20***	-0.48***
	(0.05)	(0.07)
Customers (log), when shrinking	-0.43***	-0.66***
	(0.08)	(0.07)
Observations	14,437	14,017
R^2	0.41	0.16

Note: This table is analogous to Table 4 in the main text, but the left-hand side is quantity sold per customer rather than total net revenue.

A-11

Table A10: Fixed Effects and Error Correction Models

		Miles			Resi NR			Comm NR	
	Diffs	FE	ECM	Diffs	FE	ECM	Diffs	FE	ECM
Log change in resi. cust., growing	0.385***		0.428***	0.805***		0.326			
	(0.037)		(0.117)	(0.152)		(0.370)			
Log change in resi. cust., shrinking	-0.001		0.021	0.614**		0.236			
	(0.039)		(0.059)	(0.241)		(0.618)			
Log change in comm. cust., growing	0.028		-0.031				0.896***		0.897***
	(0.020)		(0.043)				(0.120)		(0.291)
Log change in comm. cust., shrinking	-0.007		0.022				0.710***		0.548*
	(0.016)		(0.064)				(0.121)		(0.283)
Log resi. cust., growing		0.600***	0.654***		1.131***	1.208***			
		(0.058)	(0.106)		(0.120)	(0.194)			
Log resi. cust., shrinking		-0.066	0.080		0.522**	0.414			
		(0.075)	(0.119)		(0.203)	(0.381)			
Log comm. cust., growing		0.035	-0.060					1.048***	1.163***
		(0.035)	(0.104)					(0.134)	(0.226)
Log comm. cust., shrinking		0.013	-0.015					0.740***	0.760**
		(0.028)	(0.079)					(0.129)	(0.296)
Error correction			-0.526***			-0.986***			-0.971***
			(0.086)			(0.052)			(0.060)

Note: This table shows three alternative estimation strategies for the miles and net revenue results. For each dependent variable, the first column of results shows the estimation in differences that is presented in the main text. The second column shows estimation with fixed effects rather than differences. The third column shows an error correction model. Additional details of the fixed effects estimation are provided in Appendix Section A1.3.

A1.3   Fixed Effects Specifications

In Table A10, we use a fixed effects estimation strategy and an error correction model, whereas the main specifications are estimated in differences. The regression specifications with fixed effects that account for asymmetry require utility-level effects that change over time. To see this, consider the case of DTE (Detroit Edison, covering Southeast Michigan). DTE has three periods – grow, shrink, grow:

Figure A5: Example Utility With Both Growing and Shrinking Periods
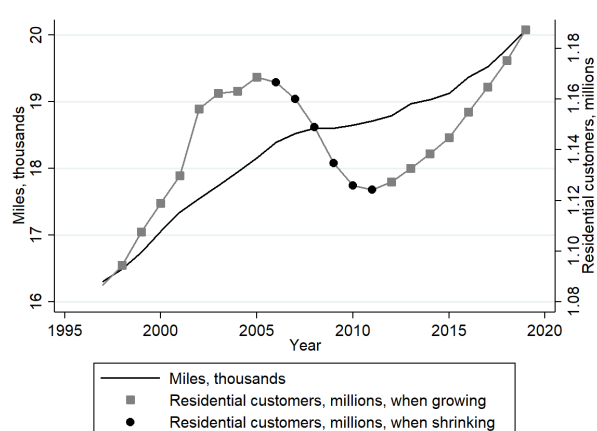
Note: This figure shows miles of pipeline and residential customer counts across time for an example utility in Michigan, DTE. The utility has periods of customer growth (grey squares) and periods of customer base loss (black circles).

The utility has periods of customer growth (grey squares) and periods of customer base loss (black circles). Throughout the sample, miles of pipeline grow, albeit at different rates in different years. In the shrink period, the growth of miles flattens out but does not turn negative. As a result, we expect to see different linear fits between the miles and customer counts variables, depending on whether the utility is growing or shrinking. Pooling across these different time periods yields a poor fit, in particularly failing to capture the flatter (and slightly negative) slope in periods when the utility's customer base is shrinking (Figure A6).

As a first step, one can estimate separate linear fits in the shrinking and growing years. For this particular example, pooling the two growth periods is provides a decent fit (left-hand
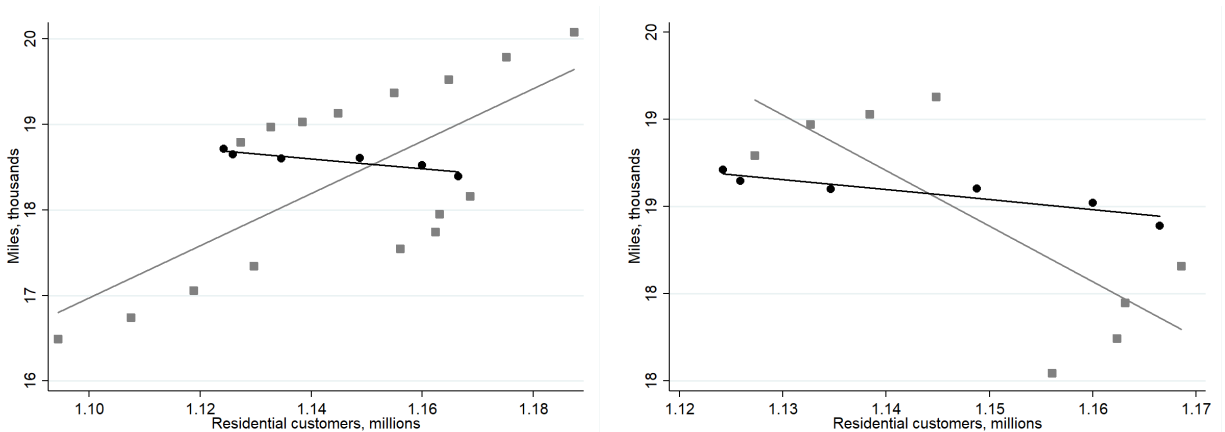
Figure A6: Failing to Account for Asymmetry
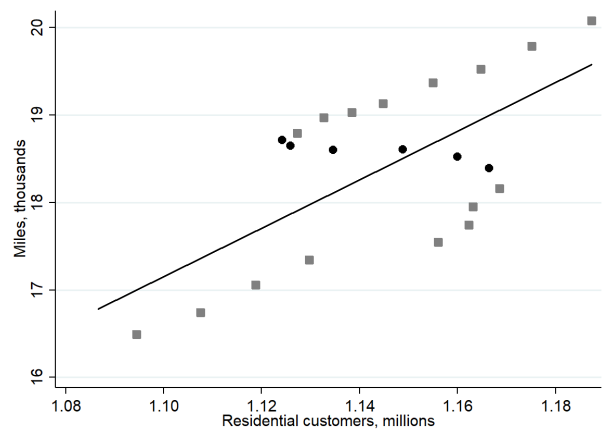
Note: This figure shows miles of pipeline and residential customer counts across time for an example utility in Michigan, DTE. The utility has periods of customer growth (grey squares) and periods of customer base loss (black circles). A linear fit is applied to all observations (black lines), showing a poor fit in the periods of customer loss.

side of Figure A7), but one can see how bias might be introduced in other contexts with multiple periods of growth. To see this more clearly, suppose that we observed only a subset of years of DTE's data, 2002-2015 (right-hand panel of Figure A7). In that case, a linear fit *across* the two periods of growth yields the wrong slope, since it fails to account for the fact that the two periods have different intercepts.
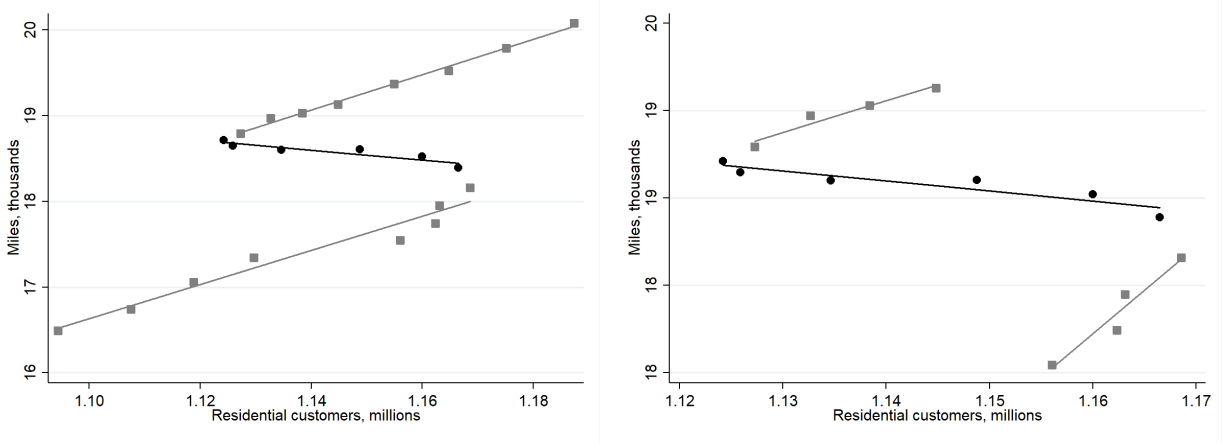
Figure A7: Failing to Include Different Period-Level Intercepts

Note: This figure shows miles of pipeline and residential customer counts across time for an example utility in Michigan, DTE. The utility has periods of customer growth (grey squares) and periods of customer base loss (black circles). Separate linear fits are applied to shrinking versus growing periods. In the right-hand panel, suppose we only observed the years 2002-2015.

To fix this problem, we can apply separate intercepts for each period (Figure A8):

Figure A8: Allowing for Separate Period-Level Intercepts

Note: This figure shows miles of pipeline and residential customer counts across time for an example utility in Michigan, DTE. The utility has periods of customer growth (grey squares) and periods of customer base loss (black circles). Separate linear fits are applied to each of three periods. In the right-hand panel, suppose we only observed the years 2002-2015.

When we apply separate linear fits for each of the three periods, we see that the data fit the linear approximation extremely well. Interestingly, the two periods of growth have similar slopes. This suggests that pooling the *slope* coefficient across these two periods is fine, as long as the *intercepts* are different, to account for the fact that each regime starts off at a different level of initial pipeline miles.

As such, in our fixed effect regressions, we allow for a different intercept (i.e., fixed effect) for each period of continued growth or continued loss of customers within a utility. In practice, this means that a typical utility will have two or three separate fixed effects (across years). For the purposes of power, we pool the slope coefficients, such that we have just one for all growing periods and just one for all shrinking periods.

A-15