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Estimating electricity distribution costs using historical data

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ABSTRACT

Electrification of heating and transportation is poised to disrupt the electric system by increasing distribution system peaks throughout the United States. This paper adds to the literature by describing the main determinants of electric distribution costs using data reported by 101 major U.S. investor-owned utilities and a set of empirical models. These models separately identify the cost of sustaining existing distribution capacity and the cost of expanding capacity to accommodate new load. It is found that growth in system capacity explains less than 10% of capital investments in the distribution system for a typical utility.

1. Introduction

Several studies have argued that increased electrification of heating and transportation, coordinated with an expansion of renewable electricity generation, can be used as a tool for economy-wide decarbonization (Electric Power Research Institute, 2018a; Steinberg et al., 2017; Larson et al., 2020). Some of these large-scale studies neglect the distribution system entirely (focusing only on generation and transmission requirements), while many others use simplified models of distribution system expenses that do not distinguish between the cost of maintaining an existing level of capacity and the cost of increasing capacity to accommodate new load. While neglecting the cost of growth in system capacity may be appropriate in a paradigm where annual load growth is only a fraction of a percent, as has been the case in recent years (Energy Information Administration, 2019d), the cost of increasing distribution system capacity will likely become more important as the electrification of heating and transportation drives increases in system peaks (Waite and Modi, 2020; Blonsky et al., 2019).

This paper contributes to the literature by describing the main determinants of electric distribution system expenses using detailed historical data from FERC Form 1. We separately examine annual capital investments and operations and maintenance (O&M) expenses for 101 major investor-owned utilities (IOUs) in the United States over eight years. We employ econometric methods to study how utility costs vary with the growth rate of the distribution system's peak capacity, the proportion of distribution assets installed underground, the geographic density of customers within the utility's service territory, and the share of sales to residential customers.

We find that all of the attributes described above are significant in explaining a utility's per-kW capital costs ($p < 0.05$). Notably, while the growth rate of a distribution system's proven capacity[1] is significant in explaining capital investments, it only accounts for a small fraction of recent investment (less than 10% for a utility with median characteristics). However, if the annual growth in peak loads increases significantly in response to electrification of heating and transportation, growth-related costs could come to represent a larger share of utilities' costs and ratepayers' bills.

None of the variables described above are significant in explaining O&M costs. The best indicator of a utility's per-kW O&M expenses is the region in which it is located, but this likely serves as a proxy for unobserved variables such as labor and regulatory compliance costs.

Section 2 discusses distribution system costs and reviews the relevant literature. Section 3 describes the sources of public data used in this analysis and the development of explanatory variables. Section 4 discusses empirical methods, including univariate, multivariate, and fixed effects regression. Section 5 summarizes the estimated coefficients and addresses their significance. Section 6 discusses the results and uncertainties. Section 7 outlines potential policy implications and highlights opportunities for future work.

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[1] "Distribution system capacity" refers to the aggregate peak load that can be accommodated by a distribution utility across its entire system. Because this is difficult to measure (it is not simply equal to the sum of transformer capacities), we use the term "proven capacity" to refer to the maximum peak load ever observed on a utility's distribution system.

[2] Non-energy expenses include all capital and O&M accounts reported to FERC, except "Power Production," "Regional Market Expenses," and investments in "Production Plant." Excluding generation costs allows for comparisons between utilities that own generation assets and those that buy energy through a wholesale electricity market.

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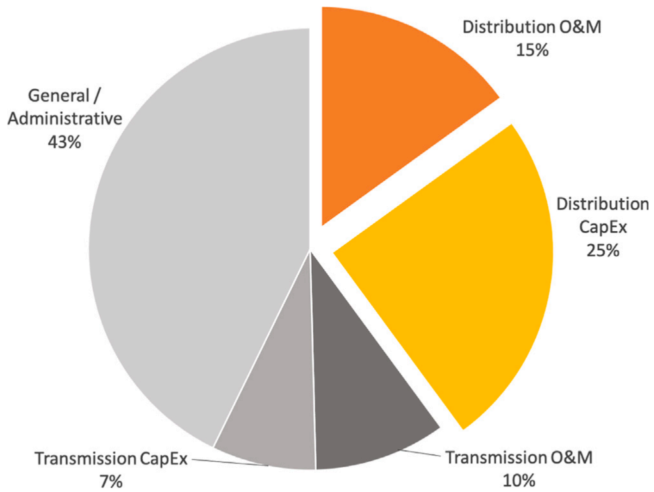

Fig. 1. Breakdown of non-energy expenses for major U.S. utilities from 2000–2007, as reported to the Federal Energy Regulatory Commission (Federal Energy Regulatory Commission, 2009). General/Administrative costs include administrative O&M, customer accounts expenses, customer service, general plant investments, investments in intangible assets, and sales expenses. This paper focuses exclusively on Distribution CapEx and Distribution O&M.

2. Background and literature review

A breakdown of a typical utility's non-energy[2] expenses is provided in Fig. 1. This paper focuses exclusively on distribution system costs, representing 40% of these expenses from 2000–2007. About 60% of these costs were devoted to capital investment and the remainder to operations and maintenance. The balance of non-energy expenses was split among transmission and general/administrative costs (Federal Energy Regulatory Commission, 2009).

Most studies focused on decarbonizing the energy system limit their focus to the generation and transmission systems. EPRI's U.S. National Electrification Assessment (Electric Power Research Institute, 2018a) predicts that efficient electrification could cause load to increase by 24%–52% by 2050. However, this work is based on EPRI's US-REGEN model, which does not impose any "constraints or expenditures related to transmission or distribution within a region" (Electric Power Research Institute, 2018b, p. 2-15). NREL's 2017 Electrification and Decarbonization report concludes that electrification of end-use services across transportation, buildings, and industrial sectors could lead to a doubling of electricity consumption by 2050 (Steinberg et al., 2017, p. vi). This analysis utilizes NREL's Regional Energy Deployment System, which only models the electricity system at the resolution of 134 balancing areas across the contiguous United States (Cohen et al., 2019). Intra-balancing area transmission and distribution are not modeled (Cohen et al., 2019, p. 57). Likewise, the EPA's Integrated Planning Model splits the contiguous United States into 67 model regions but does not model power flows within them (United States Environmental Protection Agency, 2019). MacDonald et al. (2016a) represent the transmission system with more detail but do not model local distribution systems explicitly. Instead, the authors assume that distribution costs scale proportionally with generation and transmission costs, composing 32% of the total levelized cost of energy (MacDonald et al., 2016b).

A handful of papers have used empirical approaches to estimate the drivers of utilities' distribution costs, mainly for benchmarking utilities against one another. Roberts (1986) studies financial reporting data from 65 IOUs in 1978. Notably, the author does not find evidence that increased customer density decreases costs, even when controlling for the percentage of the firm's distribution equipment installed underground. Conversely Filippini and Wild (2001), who analyze aggregate utility expenditures (minus purchased power) for 59 Swiss utilities, find that increased customer density significantly reduces distribution costs per unit of energy sold. Filippini et al. (2004) study annual reports from five Slovenian utilities from 1991 to 2000, concluding that a 1% increase in customer density reduces costs by approximately 0.60%. Yatchew (2001) studies data from 81 municipal distribution utilities in Ontario, concluding that a 10% increase in length of wire per customer increases the per-customer cost by 3.8%. Fenrick and Getachew (2012) analyze financial and technical data submitted to the Rural Utilities Service by 163 Midwestern power cooperatives located in nine states. They find that increased customer density and larger proportions of distribution lines buried underground decrease O&M costs, while a larger proportion of deliveries to residential customers increases O&M costs.

While some of these empirical studies recognize the distribution system's peak demand or capacity as a driver of costs either explicitly (using system capacity as an explanatory variable) or implicitly (normalizing costs by capacity before performing a regression against other variables), none in our review identify *increases* to peak capacity as an independent driver of costs. In contrast, utility analysts have historically characterized a large share of capital investments as causally related to growth in peak capacity. Baughman and Bottaro (1976) assume that all capital expenditures in the transmission and distribution systems are directly related to growth in capacity (measured in "miles energized" for cables and new transformer capacity for transformers), concluding that a mile of new distribution lines in some parts of the country costs three times as much as it does in others. In their 1992 guide for electric utility cost allocation, the National Association of Regulatory Utility Commissions (NARUC) recommends classifying all transmission system investments as related to load growth, except those specifically related to siting generation, interconnecting with power pools, serving specific large customers, or replacing existing equipment in kind (NARUC, 1992).[3] ICF Consulting (2005), which develops the methodology formerly used by many New England utilities for their avoided cost studies, recommends assuming as a default heuristic that 50% of transmission and distribution investments are related to load growth.[4]

When analysts model distribution costs as only a function of peak load, they are tacitly assuming that new distribution capacity can be built at a cost comparable to maintaining existing capacity. Such is the case in The Energy Information Administration's National Energy Modeling System, which assumes that capital expenses in the distribution system scale directly with the sum of the non-coincident peak loads of each customer class (Energy Information Administration, 2019c). In this model, capital expenditures range from approximately $20/kW to more than $100/kW annually, depending on the utility's region. O&M costs are modeled similarly, but with separate coefficients for capacity ($/kW) and volumetric sales ($/kWh) (Energy Information Administration, 2019b). If electrification causes peaks to double, the computed distribution costs would exactly double as well. Similarly, Vibrant Clean Energy, LLC et al. (2020) draw on the results produced by Fares and King (2017)[5] to assess the value that distributed energy resources (DERs) could offer to the electricity system, concluding

[3] NARUC's discussion of marginal distribution costs revolves around distinguishing between customer-related and capacity-related costs, paying relatively little attention to determining whether the costs identified as capacity-related are incurred because of growing peaks.

[4] Synapse Energy Economics (2018) developed a subsequent version of the methodology described in ICF Consulting (2005), this time recommending top-down accounting analyses to identify expense accounts that are primarily growth-related and discounting expenses registered in these accounts by an allowance for the cost of replacing retired equipment in kind.

[5] Fares and King (2017) use ordinary least squares (OLS) regressions to relate annual distribution costs to three predictors: total number of customers, peak load, and volumetric sales. The models that regress costs against peak loads estimate coefficients of $34/kW for capital expenditures and $18/kW for O&M.

that DERs can effectively be used to defer some distribution system reinforcements. By assuming that building new distribution system capacity bears the same annual expense as sustaining existing capacity, the authors risk underestimating the cost of significantly expanding capacity to accommodate new load.

The most rigorous treatment of distribution costs in a large-scale energy systems analysis appears to come from Larson et al. (2020), who model capital expenditures in the distribution system as the sum of the capital invested in new capacity and the cost of replacing depreciated assets. While this general approach to modeling distribution system costs is sound, the coefficient used to model the cost of new capacity ($1351/kW) is based on an estimate of the per-kW gross capital investment already made in the distribution system, not on the marginal cost of increasing capacity.[6] This approach to estimating marginal distribution capacity costs presents several problems that are discussed in Section 6.

A more common approach to estimating the cost of additional distribution system capacity – often employed by utilities and their consultants – is the marginal cost of service (MCOS) study. Since the late 1970s, electric utilities throughout the United States have regularly conducted MCOS studies as part of their rate case proceedings (Parmesano and Martin, 1983). These studies are intended to establish, among other figures, the cost in dollars of increasing distribution system capacity by one kilowatt.

While MCOS studies may appear to be a promising tool for estimating the cost of increasing distribution system capacity to accommodate electric vehicles and heat pumps, they are not well-suited to this purpose. Contemporary MCOS methodologies base their cost calculation on the value of deferring a local system expansion plan by one year (Woo et al., 1994; Hanser et al., 2018). Because this methodology is typically based only on historical and forecast expenses (rather than counterfactual expenses), a utility will develop very different estimates of their marginal distribution capacity cost ($/kW) depending on whether or not there are planned growth-related investments within the study period's time horizon (Pérez-Arriaga and Knittel, 2016). For example, as part of New York State's "Value of Distributed Resources (VDER)" order, the major utilities were directed to perform enhanced marginal cost of service studies that computed marginal capacity costs with a high level of spatial granularity (State of New York Public Service Commission, 2017). The responding utilities produced figures ranging from $0/kW for load areas with no growth-related investments (Demand Side Analytics, 2018) to those exceeding $500/kW for load areas with growth triggering costly system reinforcements (Hanser et al., 2018). While the results produced by MCOS studies may be useful for designing time-varying electricity rates and utility-administered demand response programs, they offer little insight into what to expect from sustained peak load growth due to electrification.

This paper employs a similar empirical approach to Yatchew (2001) and Fenrick and Getachew (2012) but draws on a significantly bigger dataset and includes the growth rate of system capacity as an explanatory variable to assess the impact of load growth on distribution costs. By drawing on data from 101 major U.S. utilities representing over 50% of domestic retail sales, this paper aims to establish a set of heuristics that could be used to estimate the costs associated with a prolonged expansion of distribution system capacity, as would be required to meet long-term decarbonization goals through end-use electrification.

3. Data

In this section, we discuss data sources and the development of model variables. Electric utility data were collected from multiple public sources. Financial and operational data were collected from FERC Form 1 (Federal Energy Regulatory Commission, 2009) for the years 2000 to 2007. These years were chosen because they are representative of a period of relatively high sales growth in the electricity sector. For this period, sales of electric energy grew at an average rate of 1.4% annually (Energy Information Administration, 2019d). This finding is consistent with the estimated sales growth rate in the high electrification scenario in NREL's Electrification Futures Study (Mai et al., 2018). By contrast, from 2008 until 2018, electric energy sales grew at a rate of just 0.2% annually (Energy Information Administration, 2019d; Davis, 2017).

FERC Form 1 provides financial and operating data for all major U.S. investor-owned utilities (IOUs).[7] Among these, 107 distribution utilities provided complete financial and system peak data for the selected years. Four utilities were removed from the dataset because of outlier values for either growth rate or costs. Two more were removed because a significant change in service territory (due to a merger or acquisition) made it impossible to track year-to-year growth in system capacity. The remaining 101 utilities accounted for just under 2 million gigawatt-hours (GWh) of sales in 2003, which represented 55% of that year's domestic retail electric volume (Energy Information Administration, 2019d). Because we are using eight years of data, there are 808 data points used in each regression.

There is no known public resource that records the total distribution system capacity of electric utilities. While FERC Form 1 includes reporting of individual substation capacities, inconsistencies in reporting between utilities (and between consecutive years for a given utility) make it impractical to use these data directly for our analysis. Instead, we compute the "proven capacity", $C_{i,t}$, for utility i in year t as the maximum of observed system peaks up to and including that year.[8] For example, if a utility achieved an all-time peak of 3 GW in 2001, but only 2.9 GW in 2002 (perhaps due to a cooler summer), we assume the system capacity for that year remains at 3 GW. This generates a monotonically increasing variable, $C_{i,t}$.

We separately examine capital costs and operations and maintenance (O&M) expenses for the distribution system. Capital costs include investments in buildings, poles, wires, transformers, and conduit. O&M costs include labor, purchased maintenance, and other recurring costs, as well as some sporadic costs such as repairs to storm damage (Lazar, 2016). All financial figures used herein represent actual outlays made in a given year, not depreciation. If a utility's capital expenses increase in a given year, this implies a real increase in annual spending on capital assets.

The summary statistics for proven capacity and costs are provided in Table 1. $CapEx_{i,t}$ and $OpEx_{i,t}$ describe, respectively, the capital and O&M expenses incurred by utility i in year t. To make comparisons between utilities of different sizes meaningful, our analysis centers on per-kW distribution costs, defined as distribution expenses divided by proven system capacity.[9] The total per-kW distribution capital expense is denoted $CapEx_{i,t}^{kW}$ and the total per-kW distribution O&M is denoted $OpEx_{i,t}^{kW}$. All financial figures are adjusted to 2018 dollars. Though

[6] See Fowlie and Callaway (2021) for a discussion of embedded and marginal distribution costs.

[7] Major utilities are defined as having: (1) one million megawatt-hours or more of sales; (2) 100 megawatt-hours of annual sales for resale; (3) 500 megawatt-hours of annual power exchange delivered; or (4) 500 megawatt-hours of annual wheeling for others (deliveries plus losses) (Federal Energy Regulatory Commission, 2009)

[8] The monthly system peaks for each utility are recorded in Federal Energy Regulatory Commission (2009) on page 401b, column e. The maximum of these monthly peaks is taken as the annual peak for each utility in a given year. Total Distribution Plant Additions are recorded on page 206, line 75(c). Total Distribution Expenses (O&M) are recorded on page 322, line 156(b). The copy of Form 1 data used in this analysis was accessed through S&P Global (2021).

[9] A similar approach is used in Kopsakangas-Savolainen and Svento (2008), except instead of normalizing by the proven capacity, they normalize by the volume of sales (producing a figure in $/kWh).

Table 1
Summary statistics of capital and O&M expenses, computed over 808 data points (101 utilities over eight years). $C_{i,t}$ is the proven capacity in MW. $CapEx_{i,t}$ and $OpEx_{i,t}$ are the overall distribution capital and O&M expenses for each utility. $CapEx_{i,t}^{kW}$ and $OpEx_{i,t}^{kW}$ are the per-kW (proven capacity) capital and O&M expenses.

	$C_{i,t}$ (MW)	$CapEx_{i,t}$ ($)	$OpEx_{i,t}$ ($)	$CapEx_{i,t}^{kW}$ ($/kW)	$OpEx_{i,t}^{kW}$ ($/kW)
Minimum	7	83,242	85,816	0.4	0.4
5%	86	1,403,947	1,567,595	13.2	9.2
25%	1,439	35,928,049	25,050,648	20.9	13.6
Median	3,053	69,090,853	47,744,916	27.2	17.0
Mean	4,587	131,942,503	80,364,501	28.6	20.0
75%	6,261	166,369,825	93,462,371	34.5	23.4
95%	16,789	496,617,661	271,851,419	51.0	42.8
Maximum	23,613	1,114,231,772	593,461,903	81.0	92.5
Standard Deviation	4,853	172,216,133	96,372,471	11.6	11.2

Table 2
Summary statistics of the explanatory variables. *Growth* is the annual growth rate of system peak, computed over a 5-year rolling window. *Density* is the density of customers in the utility's service territory (customers/square-mile). *Underground* is the proportion of total distribution assets categorized as either underground conductors or underground conduit. *Residential* is the proportion of volumetric energy sales to residential customers (compared to commercial or industrial).

	$Growth$	$\ln(Density)$	$Underground$	$Residential$
Minimum	0%	−1.1	0%	0%
5%	0%	1.2	5%	21%
25%	0.7%	2.9	11%	30%
Median	1.6%	3.7	18%	35%
Mean	1.9%	3.6	19%	34%
75%	2.7%	4.6	23%	39%
95%	4.8%	5.8	38%	47%
Maximum	8.3%	6.7	46%	73%
Standard Deviation	1.5%	1.4	10%	9%

overall costs vary by several orders of magnitude between utilities of different sizes, the per-kW capital and O&M costs exhibit considerably less variability.

The growth rate of proven capacity, $Growth_{i,t}$, is computed using a 5-year rolling window.[10] This is described in Eq. (1), which is an inversion of the classic "compounding interest" formula. This approach is similar to how Mai et al. (2018) compute the compounding annual growth rate of electricity sales.

$$Growth_{i,t} = \left[\frac{C_{i,t+2}}{C_{i,t-2}}\right]^{1/4} - 1 \tag{1}$$

To compute customer density, $Density_{i,t}$, the total number of customers for utility i in year t is divided by the utility's service territory area in square miles. This area is computed using the Department of Homeland Security's Electric Retail Service Territories database (Department of Homeland Security, 2019).[11] We expect a negative correlation between density and distribution costs because higher density means more load can be served by a single length of feeder (Filippini and Wild, 2001; Filippini et al., 2004; Yatchew, 2001).

The percentage of underground assets, $Underground_{i,t}$, is computed as the ratio of the gross value of underground conduit and conductors divided by the gross value of all distribution assets. Larger shares of underground assets would be expected to increase capital costs (more labor is required to bury a line), though this may be offset in part by a reduction in O&M costs (fewer lines are likely to be damaged in a storm) (Fenrick and Getachew, 2012).

$Residential_{i,t}$ is defined as the proportion of volumetric sales (kWh) to residential customers.[12] Higher proportions of sales to residential customers are expected to increase distribution costs (Fenrick and Getachew, 2012).

Summary statistics for the explanatory variables are provided in Table 2. These statistics describe a highly heterogeneous set of observations. While the mean and median observed growth rates of system capacity are broadly consistent with the growth rate of aggregate energy sales projected in Mai et al. (2018), at least 5% of utility-year combinations have no observable growth in proven capacity. Likewise, 5% of observations have annual growth rates exceeding 4.8%.

Customer density, like population density in general, is found to be exponentially distributed in the dataset. The maximum observed value for customer density is twenty times larger than the median. In all regressions that include customer density, a natural log transformation is used. This method prevents a few utilities with very high densities from distorting the results.

We also note the sizable range in investments in underground assets and sales to residential customers. There are examples of utilities with no underground conductors or conduit, as well utilities with nearly half of their distribution assets underground. Similarly, for some utilities, nearly three-quarters of sales are to residential customers. Others exclusively serve commercial and industrial loads (*Residential* = 0%);

4. Methodology

In order to develop an empirical model of electric distribution system costs, we perform a series of regressions relating per-kW capital and O&M expenses to various factors, including the growth rate of proven system capacity, the proportion of distribution assets installed underground, the natural logarithm of customer density within the utility's service territory, and the share of sales to residential customers.

In the first model, we run a simple ordinary least squares (OLS) regression of the per-kW capital costs on the estimated growth rate of proven capacity. Observations are weighted by the utility's proven capacity so that the resulting model parameters can be understood to represent the costs associated with an average unit of capacity across all utilities. The formulation for this model is described in Eq. (2), where $Growth_{i,t}$ is the growth rate of system capacity in percentage points, the β terms are the estimated intercept and coefficient, $Year_t$ is a fixed effect for the year, and $\epsilon_{i,t}$ is an error term.

$$CapEx_{i,t}^{kW} = \beta_0 + \beta_{Growth} Growth_{i,t} + Year_t + \epsilon_{i,t} \tag{2}$$

The regression's fit is visualized in Fig. 2. Each point on the scatter plot of per-kW capital cost vs. growth rate represents one utility for one year, where the size of the point is proportional to the utility's proven capacity. Points on the left side of the plot represent utilities in years with low load growth, while points further to the right represent utilities that are rapidly expanding their system capacity. The best-fit line delineates the weighted regression described above. The intercept

[10] Measuring growth only between consecutive years would produce a computed growth rate of zero for years in which the observed system peak does not increase, even if utilities are investing in anticipation of future load increases. Furthermore, electric utilities plan their investments over several years, and large capital expenditures tend to either respond to anticipate significant increases in system peak. Consequently, investments associated with load growth and a related increase in proven capacity do not necessarily occur in the same year. Appendix B presents results for the regressions performed using different estimates of the growth rate. In order to compute the growth rates for the entire 8-year window from 2000–2007 (inclusive), we include observed system peaks from 1998–2009.

[11] The DHS database only reports current service territory data. If a utility's service territory changed significantly between the study years and the most recent update of the DHS database, this would not be captured in our estimate of customer density.

[12] The total number of retail customers is recorded in Federal Energy Regulatory Commission (2009) on page 301, line 12f. The gross values of underground conductors and underground conduit are recorded on page 207, lines 66g and 67g, and the gross value of all distribution assets is recorded on line 75g. The volumetric sales to residential customers are recorded on page 301, line 2d. The total volumetric sales to all customers are recorded on page 301, line 12d.

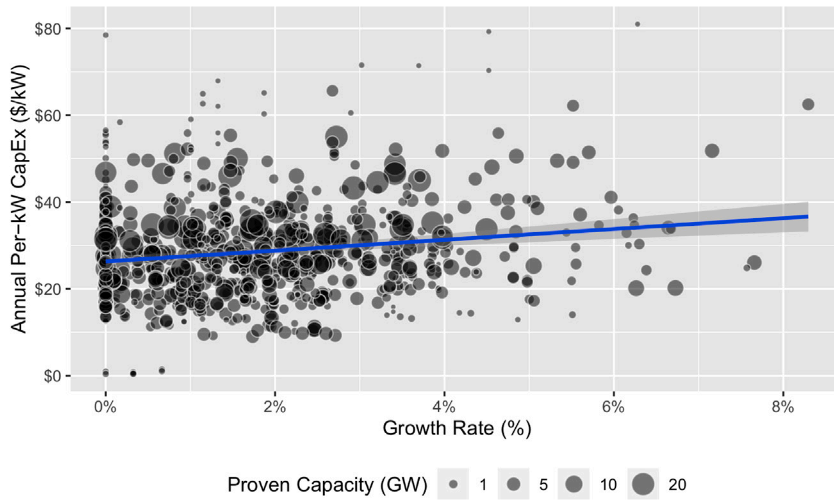

Fig. 2. Relationship between per-kW-capacity distribution capital costs and growth rate for major U.S. utilities; 808 points representing 101 utilities over eight years. The best-fit line represents the univariate regression of $CapEx_{i,t}^{kW}$ on $Growth_{i,t}$, weighted by the utility's proven capacity, $C_{i,t}$. The shaded region covers a level 0.95 confidence interval.

on the y-axis (which includes the intercept term as well as the mean of the fixed effects) is the average per-kW distribution cost for the case of no growth, estimated as $\beta_0 + \overline{Year_t}$. This statistic describes the per-kW distribution capital cost associated with sustaining a given capacity level through routine replacement of equipment. The slope of the best-fit line describes the growth rate-coefficient, β_{Growth}, which is the change in per-kW costs in response to a one percentage point increase in the growth rate. The alternative specifications described below include additional explanatory variables but follow the same basic architecture.

In the second empirical model, we add controls for the previously discussed utility attributes: the percentage of underground assets, the natural logarithm of customer density, and the share of sales to residential customers. If any of these variables independently affect distribution costs and are correlated with growth (e.g., if load is growing more rapidly in dense cities due to urbanization), then omitting them would produce a biased estimate of β_{Growth}. The formulation for this model is described in Eq. (3), which modifies Eq. (2) by adding $\boldsymbol{X}$, a matrix of the attribute variables, and $\boldsymbol{\beta}$, a vector of associated coefficients to be estimated. Under this formulation, the average per-kW cost of maintaining an existing capacity level without growth is estimated as $\beta_0 + \overline{\boldsymbol{X}\boldsymbol{\beta}} + \overline{Year_t}$.

$$CapEx_{i,t}^{kW} = \beta_0 + \boldsymbol{X}\boldsymbol{\beta} + \beta_{Growth}Growth_{i,t} + Year_t + \epsilon_{i,t} \quad (3)$$

In addition to these characteristics, we expect distribution costs to vary with other factors, including the regulatory environment, the price of inputs (including labor and materials), weather, and the geographic terrain. As some of these factors are difficult to quantify accurately, we use indicator (dummy) variables for the utility's region, R_i,[13] as a proxy. This method is expected to capture some of this unobserved heterogeneity without overfitting the model (as a state-level indicator would likely do). The region variable is commonly used as an indicator of electric system costs in energy modeling exercises (Baughman and Bottaro, 1976; Energy Information Administration, 2019c).[14] It is included in the third and fourth models.

It seems reasonable to expect that the factors that affect the cost of maintaining an existing level of distribution capacity could also affect the cost of increasing that capacity. We address this by including interaction terms between each of the attribute variables and the growth rate in the fourth regression. For example, if having a large proportion of underground assets means that it is more costly to upgrade distribution infrastructure to accommodate a higher peak, this would be captured in the fourth regression as an interaction between $Growth$ and $Underground$.

Finally, a fifth model includes fixed effects for each utility, denoted $Utility_i$. This approach, described in Eq. (4), removes the unobserved time-invariant characteristics particular to each utility. These include the utility attributes used in the multivariate regression (which are not perfectly constant from year to year, but exhibit little variation for a given utility) as well any constant features that vary between utilities but do not significantly change during the study period (such as labor and policy costs). This approach does not remove the effects caused by time-varying heterogeneity specific to each utility, such as state-specific regulatory changes that occur within the study period. However, because a separate fixed effect is included for the year in all models, country-wide trends that affect costs for all utilities are captured. Of the models discussed, this formulation provides the highest degree of confidence that the estimated growth rate coefficient is unbiased.

$$CapEx_{i,t}^{kW} = \beta_0 + \beta_{Growth}Growth_{i,t} + Year_t + Utility_i + \epsilon_{i,t} \quad (4)$$

The above formulations are also used to estimate models for O&M expenses, $OpEx_{i,t}^{kW}$. The results of these regressions are presented in Section 5.2.

[13] The utilities are divided into six regions: Mid-Atlantic, New England, Southeast, Southwest, Midwest, and West. Mid-Atlantic is treated as the reference group in the regressions that include a fixed effect for the region. Summary statistics for each individual utility, including its region, are included in Table C.10.

[14] Baughman and Bottaro (1976) divide the continental United States into nine regions, finding significant differences in costs. Energy Information Administration (2019c) groups U.S. utilities into 22 different regions and finds that the highest-cost region (New York City and Westchester, NY) has unit costs that are more than five times those in the lowest-cost regions (Texas, Michigan, and Wisconsin).

5. Results

5.1. Capital expenses

Table 3 summarizes the results of the regressions of per-kW capital costs. The rows are the explanatory variables described in Section 3, the columns represent the different specifications described in Section 4, and the value in each cell is the β-coefficient associated with a variable for a given model, with the standard errors in parentheses.

Column (1) presents the results from running capital costs on growth without controls. The intercept term (which includes the average of the fixed effects) is interpreted as the per-kW recurring cost for sustaining a given capacity level. According to this model, an average utility with no load growth will spend $26.47 per-kW each year on distribution-related capital projects. These may be incurred to improve reliability and resilience or comply with new standards. A hypothetical utility with a 1 GW ($1e6\,kW$) peak and zero growth would be expected to spend $\$26.47 * (1e6kW) = \$26,470,000$ each year on sustaining distribution capacity.

The growth rate coefficient, β_{Growth}, is the change in a utility's per-kW capital expenses when its growth rate increases by one percentage point. In the first specification, this cost is estimated as $1.70 per-kW-percentage-point. If the hypothetical utility described above increases its capacity by 1% (10 MW) in a given year, it would be expected to spend an additional $\$1.70 * (1e6\,kW) * (1\,percentage\,point) = \$1,700,000$ on growth-related costs, which amounts to $170 per new kilowatt of capacity. If the utility's proven capacity stays constant in subsequent years, then it would be expected to spend $\$26.47 * (1.01e6\ kW) = \$26,734,700$ each year in capital expenses to sustain that capacity. In this way, an increase in capacity to accommodate new load results in both an upfront cost as well as recurring annual costs.

It should be stressed again that because the first model does not account for some important factors that are likely to be correlated with growth, it is likely that the estimated coefficients are biased. Column (2) presents results for the multivariate regression that controls for the proportion of underground assets (percentage points), the natural log of customer density per square mile, and the share of sales to residential customers (percentage points). The regression in column (3) includes these variables and the region dummy. Notably, the estimated coefficient for growth rate in these formulations is only $0.67–$0.74 per-kW-percentage-point, less than half of the value estimated in the model run without controls. This finding suggests that some part of the correlation between high per-kW costs and the high growth rate observed in the first regression is better explained by other features of the utility.[15]

The coefficient for the proportion of underground assets describes the increase in annual per-kW capital costs for a utility when the share of underground assets increases by one percentage point. According to column (2), utilities with a one percentage point higher proportion of their assets underground spend $0.57 more per-kW of capacity each year on capital expenses. For column (3), this number is estimated at $0.34 per-kW.

Our results also suggest that utilities with higher customer densities have lower distribution costs. If the natural log of customer density increases by one, distribution capital costs decrease by $1.69 per-kW according to the specification in column (2). This finding is likely because a given length of conduit or conductor in a dense region can serve more customers (and more load) than the same asset in a less dense region. This effect is not significant when we add regional dummies, perhaps in part because the region variable captures some of the same variation in the underlying data. Per-kW capital costs also increase with a higher share of residential customers, which is consistent with the results presented in Fenrick and Getachew (2012).

Results in column (3) indicate that the utility's region is also significant in explaining distribution capital costs. For a utility located in New England, the annual cost of maintaining a given level of peak capacity is $17.40 per-kW more than the reference utility located in the Mid-Atlantic region. While not all regions demonstrate statistically different costs than the Mid-Atlantic, the set of indicator variables as a whole are highly significant (a partial F-test yields a statistic of 91). Inclusion of the region variable increases the adjusted R-squared from 0.365 to 0.594.

The multivariate regression with interaction terms (column 4) tests whether some of the variables that impact the cost of maintaining a given capacity level also impact the cost of growth. We find that none of the interaction coefficients computed are statistically significant and that the inclusion of the interaction terms does not improve the adjusted R-squared over the formulation summarized in column (3), nor does it provide a statistically different fit (F = 0.808). Statistical interactions are challenging to prove with regression and often require a significantly larger dataset than primary effects (Gelman, 2018). With only 808 data points, the failure of this exercise to prove that attributes like customer density affect a utility's growth cost does not rule out the possibility of an underlying relationship.

Table 3
Results from regression models of distribution capital expenses. The coefficient in the *Growth* row describes the dollar-per-kW increase in distribution capital costs when the growth rate increases by one percentage point. Values in parentheses are the standard errors clustered by utility. The mean of the fixed effects is included in the intercept term. For the formulation in column 5, the intercept is computed by separately calculating the means of the fixed effects for year and utility and adding these together. To compute the standard error for the intercept, we compute separate clustered standard errors for each year and utility by bootstrapping, compute the mean standard error for each group, then combine these using a root-mean-square calculation. For columns 3 and 4, the reference region described by the intercept term is the Mid-Atlantic.

	Annual Per-kW Distribution Capital Costs				
	(1)	(2)	(3)	(4)	(5)
Intercept	26.47***	14.30***	15.37***	12.79***	27.20***
	(1.41)	(1.07)	(0.75)	(0.74)	(0.54)
Growth	1.70***	0.74**	0.67**	2.04	0.76***
	(0.53)	(0.35)	(0.27)	(1.52)	(0.20)
Underground		0.57***	0.34***	0.34***	
		(0.11)	(0.10)	(0.12)	
ln(*Density*)		−1.69***	−0.27	0.02	
		(0.65)	(0.78)	(0.91)	
Residential		0.23**	0.12*	0.17	
		(0.11)	(0.07)	(0.10)	
Midwest			−0.85	−0.87	
			(1.81)	(1.83)	
New England			17.40***	17.30***	
			(2.93)	(2.98)	
Southeast			1.43	1.45	
			(2.06)	(2.05)	
Southwest			−2.05	−2.13	
			(2.70)	(2.70)	
West			10.85***	10.84***	
			(3.34)	(3.35)	
*Growth***Underground*				0.003	
				(0.03)	
*Growth**ln(*Density*)				−0.17	
				(0.25)	
*Growth***Residential*				−0.02	
				(0.03)	
R^2	0.065	0.373	0.602	0.603	0.072
Adjusted R^2	0.055	0.365	0.594	0.594	−0.071
Observations	808	808	808	808	808
Year Fixed Effects	X	X	X	X	X
Utility Fixed Effects					X

*p<0.1; **p<0.05; ***p<0.01.

[15] The intercept coefficients are also nominally smaller because the newly-added explanatory variables capture part of the sustaining cost. A detailed discussion of growth and sustaining costs is included in Section 6.

Column (5) presents results from the regression that includes utility fixed effects. This specification estimates a growth rate-coefficient of \$0.76 per-kW-percentage-point, consistent with the estimated coefficients computed in columns (2) and (3). These findings indicate that the estimates obtained from the multivariate analyses are not likely biased by omitted time-invariant heterogeneity between utilities. Other potential sources of bias in the estimated coefficient for growth rate are discussed in Section 6.

5.2. Operations and maintenance costs

We repeat the regression models used to explain per-kW capital expenses, this time with per-kW O&M as the dependent variable. Regression results are summarized in Table 4.

Notably, we do not find any statistically significant relationships in the specifications in columns (1) or (2). Adding the regional dummies in column (3) improves the fit, raising the adjusted R-squared to 0.353. New England utilities have the highest O&M costs, incurring \$11.60 per-kW more each year than Mid-Atlantic utilities. For O&M costs, the region variable likely serves as a proxy for labor, insurance, and other input costs that vary throughout the country.

Table 4
Results from regression models of distribution O&M expenses. Notably, there is no statistically significant relationship observed between O&M costs and the growth rate of system capacity. Values in parentheses are the standard errors clustered by utility. The mean of the fixed effects is included in the intercept term. For the formulation in column 5, the intercept is computed by separately calculating the means of the fixed effects for year and utility and adding these together. To compute the standard error for the intercept, we compute separate clustered standard errors for each year and utility by bootstrapping, compute the mean standard error for each group, then combine these using a root-mean-square calculation. For columns 3 and 4, the reference region described by the intercept term is the Mid-Atlantic.

	Annual Per-kW Distribution O&M Costs				
	(1)	(2)	(3)	(4)	(5)
Intercept	17.61***	17.69***	24.12***	19.75***	19.71***
	(0.8)	(0.8)	(0.6)	(0.7)	(0.3)
Growth	0.25	0.31	0.09	2.44	0.12
	(0.36)	(0.33)	(0.28)	(1.56)	(0.14)
Underground		−0.03	−0.08	0.06	
		(0.09)	(0.07)	(0.08)	
ln(*Density*)		0.35	−0.51	−0.99	
		(0.61)	(0.74)	(0.66)	
Residential		−0.02	0.04	0.12	
		(0.08)	(0.08)	(0.09)	
Midwest			−4.19*	−3.87	
			(2.45)	(2.41)	
New England			11.56***	12.01***	
			(3.51)	(3.58)	
Southeast			−7.69***	−7.36***	
			(2.75)	(2.70)	
Southwest			−9.94***	−9.67***	
			(3.08)	(3.05)	
West			−0.61	−0.23	
			(4.17)	(4.11)	
*Growth***Underground*				−0.06**	
				(0.03)	
*Growth**ln(*Density*)				0.22	
				(0.28)	
*Growth***Residential*				−0.04	
				(0.03)	
R^2	0.003	0.006	0.366	0.392	0.006
Adjusted R^2	−0.007	−0.007	0.353	0.377	−0.147
Observations	808	808	808	808	808
Year Fixed Effects	X	X	X	X	X
Utility Fixed Effects					X

*p<0.1; **p<0.05; ***p<0.01.

6. Discussion

The results suggest that while increases in system capacity are significant in explaining electric distribution capital costs, they represent a relatively small share of those costs. The majority of a typical utility's annual capital expenses are associated with sustaining a given capacity level, as described by the intercept term and attribute coefficients. Fig. 3 depicts the proportion of capital costs related to growth for a single year for an electric utility with median characteristics.[16] At a typical annual growth rate between 1%–2%, less than 10% of capital costs are explained directly by load growth. Even at an annual growth rate of 5%, less than 20% of a generic utility's annual distribution capital expenses are directly related to load growth.

The estimates of the increase in distribution costs from load growth are lower than many previous estimates, such as ICF Consulting (2005), which assumes that 50% of transmission and distribution investments are causally related to load growth. A review of infrastructure filings from state public service commissions indicates that it is not uncommon for utilities to report that load growth is only responsible for a small portion of their capital expenses. As part of its 2017 rate case, Central Hudson Gas & Electric Company in New York State reported a detailed schedule of its forecasted capital expenses from 2018–2022. Only 3% of capital investments in the distribution system were labeled as related to load growth (Central Hudson Gas & Electric Corporation, 2017, p. 120-122).[17] In California, Pacific Gas & Electric spent an average of \$99 million annually on projects related to expanding electric distribution capacity in 2000 and 2001 (Pacific Gas & Electric, 2018). This amounts to just 16% of their average distribution capital expenses for those years (Federal Energy Regulatory Commission, 2009).[18]

Multiplying the growth rate coefficient by a factor of 100 gives an estimate of the cost of an incremental unit of distribution capacity.[19] Our results indicate that this figure is around \$75/kW. This finding is an order of magnitude smaller than the estimate used in Larson et al. (2020), which assumes that new capacity costs \$1351/kW on average. There are several explanations for this discrepancy. For one, the authors draw on estimated distribution costs from Energy Information Administration (2019a), which includes administrative expenses (such as salaries and office space) as part of the distribution charge (Energy Information Administration, 2019b, p. 17). While some of these expenses may grow over time, it is not reasonable to assume that a doubling of per-capita electricity consumption would result in a doubling of administrative expenses. Additionally, a large proportion of distribution expenses – including land rights, structures, poles, towers, service drops, and meters – are not directly related to the level of consumption. If customers were to increase their loads by electrifying their heating and transportation needs, a utility may need to upgrade some of its transformers but would not necessarily need to replace its poles or on-site meters. Administrative and distribution expenses that are unlikely to increase in response to an increase in load should be excluded from an estimate of the marginal distribution capacity cost based on accounting methods.[20] Furthermore, the accounting-based

[16] Per Table 2, a utility with median characteristics has a proven capacity of 3 GW, 40 customers per square mile ($ln(Density) = 3.7$), 18% of distribution assets invested as either underground conductors or underground conduit, and 35% of sales to residential customers.

[17] The rate case filings corresponding to the time period of this study did not include granular project data that could be used to distinguish between growth-related and maintenance costs.

[18] We do not know of any public dataset that separately reports growth and maintenance costs incurred by a large sample of utilities. Such a dataset would help validate the empirical conclusions of this study.

[19] An example of this arithmetic, applied to the univariate regression, is provided in Section 5.

[20] See Lazar (2016, Chapter 9.2) for a discussion of how investments in the distribution system are classified as customer vs. load-related.

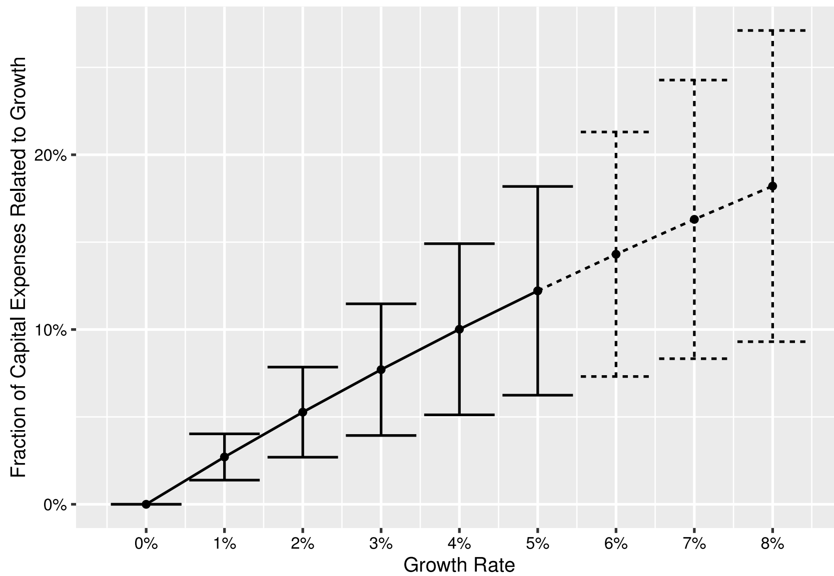

Fig. 3. Upfront growth costs as a proportion of total distribution capital expenses vs. growth rate of system peak. For each percentage point on the *x*-axis, separate "growth" and "sustaining" costs are computed for a typical utility using the specification in Table 3, column (2), and the ratio of growth costs to overall distribution capital costs is plotted. Error bars are computed using the clustered standard errors of the growth rate coefficient. There is limited data for growth rates over 5%, so those estimates (represented with dashed lines) should be regarded as extrapolations.

approach is very sensitive to changes in assumptions about the cost of capital and the economic life of utility assets. Increasing the discount rate used in Larson et al. (2020) from 4.4% to 8% and decreasing the equipment life from 40 years to 30 nearly halves the estimated per-kW cost of distribution assets.[21]

Another important observation is that the share of underground distribution assets significantly increases recurring capital costs. Some of the fastest-growing utilities (measured by the growth rate of proven capacity) are also engaging in the most aggressive undergrounding campaigns. For example, Nevada Power Company, which more than doubled its proven system capacity from 1994 to 2007, also increased the proportion of its assets invested as either underground conductors or conduit from 33% to 44% over the same period. While burying power lines offers myriad advantages to a utility's customers (such as improved reliability and aesthetics), those benefits should be weighed against costs and alternatives should be considered where appropriate.

Because a utility's peak load and the number of customers it serves are highly correlated,[22] we did not attempt to distinguish between costs incurred to facilitate an increase in capacity and those incurred to accommodate an increase in the number of customers. Thus, some of the costs attributed to load growth in this analysis may be causally related to an increase in the number of customers (such as expenditures on new meters and service drops). In a future where significant load growth is caused by electrification, one would expect an increase in peak-related infrastructure costs but not necessarily in customer-related costs. The results from four separate regressions of different categories of distribution capital costs are provided in Appendix A.

6.1. Long-term growth costs

When considering persistent load growth over an extended period, as would be expected from increased electrification of heating and transportation, both the upfront cost of new distribution capacity as well as recurring capital and O&M costs associated with that infrastructure should be taken into account. This section presents an extrapolation exercise in which we use the estimated parameters from Section 5 to compute the distribution costs for a utility from 2022 to 2035 under different growth scenarios.

This exercise uses the estimated parameters from column (2) of Tables 3 and 4 to forecast capital and O&M expenses.[23] We take the attributes of a typical 3 GW utility with 40 customers per square mile, 18% underground assets, and 35% of volumetric sales to residential customers, then assume five different capacity growth rates: 0%, 0.5%, 1.5%, 3%, and 5%. The resulting distribution expenses over time are plotted in Fig. 4.

In the zero-growth scenario, the utility spends $132 million annually between capital and O&M costs to maintain 3 GW of capacity. In the 0.5% growth rate scenario, the utility spends an additional $93 m over the 14-year horizon to build and maintain an additional 217 MW of capacity by 2035. In the extreme case of 5% annual growth, the utility nearly doubles capacity while incurring $1.19b in additional expenses over the time horizon. A comprehensive summary of these results is provided in Table 5.

Since both capital and O&M costs are dominated by recurring annual expenses (rather than the one-time cost of increasing capacity, as described by the growth rate coefficient), we find that the growth rate has a relatively modest impact on average distribution costs. Assuming that load factors remain constant at approximately 60%[24] and that new

[21] See Zhang et al. (2020) for a detailed description of the methodology used to produce the marginal capacity cost figure from Larson et al. (2020).

[22] The data used in this study indicate no statistically significant increase in proven capacity-per-customer from 2000–2007. Proven capacity and total customer count have a correlation coefficient of 0.95, making them functionally collinear (the logs of these variables have a correlation coefficient of 0.96).

[23] While the column (2) specification was used for simplicity, one would expect similar results from columns (3) and (5).

[24] The load factor describes the ratio of the average consumption of electricity to the observed peak. Electric vehicles are likely to increase load factors because they can be charged off-peak, leading to flatter daily consumption curves. Electric heating is poised to decrease load factors in areas where significant buildout is required to accommodate winter peaks.

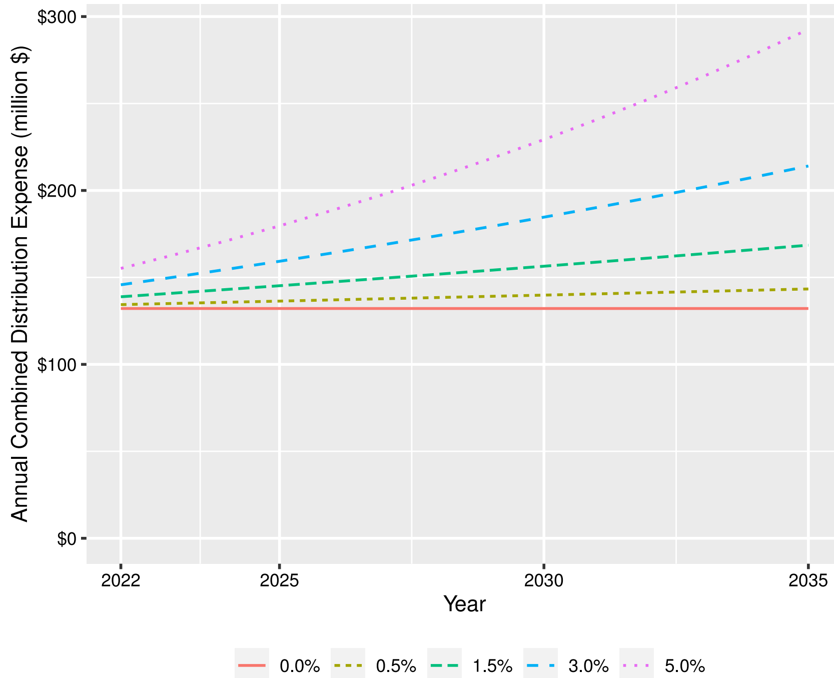

Fig. 4. Annual distribution expenses (capital + O&M) for a typical 3 GW utility at five different growth rates from 2022–2035 (inclusive). The higher growth rates represent scenarios with aggressive electrification of heating and transportation. In the 5% growth rate case, annual expenses nearly double between 2022 and 2035.

Table 5
Growth rates and associated expenses for a typical 3 GW utility over the 14-year interval from 2022–2035 (inclusive). "Total Expenses" and "Additional Expenses" are aggregated (undiscounted) over the entire 14-year interval. "Capacity Increase" and "Additional Expenses" are measured in reference to the 0% growth case. "Average Electricity Cost" estimates the average distribution cost in $/MWh, assuming a constant load factor of 60% and that all expenses are recovered in the same year that they are incurred. If volumetric sales scale linearly with peak, then a 5% growth rate is only expected to increase delivery expenses by about $1/MWh ($0.001/kWh) over the zero-growth scenario. If expenses are discounted at an annual rate of 8%, the present value of distribution expenses (capital plus O&M) over the 14-year interval range from $1089 m for 0% growth to $1686 m for 5% growth.

Growth	Capacity		Total Expenses		Additional		Average
Rate (%)	Increase (2035) (MW)	(%)	Capital (millions)	O&M (millions)	Expenses (millions)	(%)	Distribution Cost ($/MWh)
0.0%	–	–	$1,113	$737	–	–	$8.38
0.5%	217	7%	$1,172	$772	$93	5%	$8.48
1.5%	695	23%	$1,299	$847	$296	16%	$8.68
3.0%	1538	51%	$1,516	$975	$641	35%	$8.98
5.0%	2940	98%	$1,863	$1,178	$1,191	64%	$9.37

capital costs are born by ratepayers in the year they are incurred, a 5% growth rate would only increase the average distribution cost by about $1/MWh (0.1 cents/kWh) over the zero-growth scenario.

To provide a point of comparison, if one applies the methodology from ICF Consulting (2005) (assuming that distribution capital expenses are evenly split between growth and maintenance costs and that all O&M costs are unrelated to growth) to the complete data from 101 utilities, the median upfront cost of new capacity across all utilities is $578 per-kW and the median annual cost of sustaining existing capacity is $30 per-kW (capital plus O&M). If these coefficients are applied to the typical 3 GW utility above, the forecast expenditure over the 14-year interval is $1.26 billion in the zero-growth case and $3.55 billion in the 5% growth case, a 182% increase. This difference would amount to an increase of over $5/MWh (0.5 cents/kWh) in distribution costs, from $5.06/MWh in the zero-growth case to $10.30/MWh in the 5% annual growth case. Relative to the empirical model, the 50% heuristic appears to underestimate sustaining costs and overestimate the cost of increasing capacity for new load.

Conversely, if one assumes that distribution costs are correlated only with the distribution system's peak capacity (as is assumed in Vibrant Clean Energy, LLC et al. (2020) and Energy Information Administration (2019c)), then the average cost of distribution ($/MWh) would be entirely independent of the growth rate of the system peak. This assumption could lead analysts to underestimate how rapid growth due to electrification might impact ratepayers.

7. Conclusion and policy implications

We described the main determinants of electric distribution costs using annually-reported financial and operating data from 101 investor-owned utilities over eight years. We found through regression analysis that the growth rate of proven capacity, the proportion of assets installed underground, the density of customers within the utility's service territory, and the share of sales to residential customers are all significant in explaining per-kW distribution capital costs. None of the above variables were found to be useful in explaining O&M costs. The only reliable explanatory variable we found of per-kW O&M costs is the utility's region. Regional dummies, which explain part of the variation in capital and O&M costs, likely serve as proxies for other unobserved variables that change locally (such as labor or policy costs). Future work should identify these factors and quantify their effects directly.

Based on historical system peaks, we estimate that load growth represents less than 10% of distribution capital costs for a typical utility with an annual capacity growth rate of 1%–3%. A 5% growth rate from 2021–2035 would nearly double distribution capacity while only increasing the average distribution cost by about $1/MWh (0.1 cents/kWh) relative to the zero-growth case. These results indicate that many of the distribution system reinforcements needed to accommodate widespread electrification of heating and transportation are achievable without significantly increasing costs to consumers.

Another notable result of our analysis is that distribution system costs vary widely throughout the country and between utilities with different attributes. This finding suggests that widespread electrification of heating and transportation may become economical for some utilities before others. The Southwest has the lowest distribution costs (both capital and O&M), making Southwestern customers prime candidates for early adoption of end-use electrification as the grid becomes cleaner.

In conducting this analysis, we found that limited centralized data on distribution infrastructure posed a significant challenge to comparing capacity and growth between utilities. While utilities report transmission line additions to FERC, no such data are reported for distribution infrastructure. Moreover, while substation capacity data is reported, inconsistencies in reporting make it impractical to use these data for empirical analysis. If loads are growing in one part of a utility's service territory and shrinking in another, the approach used in this analysis (based only on observed peaks) would be unable to detect changes to aggregate system capacity. Standardized reporting of distribution line miles and aggregate transformer capacities would enable more accurate modeling in future work.

Load growth from electrification may be faster than recent trends and will likely come from higher per-customer consumption rather than growth in the number of customers. Because of the speed at which heating and transportation would need to be electrified in order to meet decarbonization goals, utilities should begin incorporating electrification into their infrastructure planning as soon as possible. Our estimates may serve as a helpful reference for practitioners and policymakers engaged with this effort.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Disaggregated capital costs

In recent years, per-capita electricity consumption has remained relatively constant (Energy Information Administration, 2017), so most measured load growth has come from an increase in the number of customers rather than an increase in per-customer consumption. Because load growth and customer growth are so tightly coupled, it is difficult to distinguish between those expenditures that are causally related to an increase in load (such as upgraded transformers) and those that are customer-related but correlated with an increased system peak (such as the installation of new meters). Because electrification of heating and transportation is poised to increase per-customer load, it is valuable to separate load-related expenses from customer-related expenses.

One approach to separating load effects and customer effects would be to include measurements of both in the model formulation. However, because these two variables are highly collinear (more customers produce a higher peak), coefficient estimates derived from this regression are unreliable. This was observed by Fares and King (2017), who chose to perform separate regressions for three explanatory variables: system peak, number of customers, and volumetric sales.

Sidestepping this problem, we use the disaggregated "account-level" capital expense data from FERC Form 1, categorizing each expense into one of four categories: Load, Conductors, Access, and Customers.[25]

Table A.6
Summary statistics of distribution capital expenses by category. For a typical utility, investments in transformers and conductors represent over 60% of per-unit capital costs. The aggregate per-kW costs are reported in Table 1.

	Load ($/kW)	Conductors ($/kW)	Access ($/kW)	Customer ($/kW)
Minimum	0.09	0.16	0.00	−0.60
5%	2.80	3.62	2.13	1.13
25%	5.54	6.02	3.90	2.61
Median	7.82	8.10	5.25	3.89
Mean	8.13	9.46	5.91	4.35
75%	10.29	11.03	7.41	5.42
95%	14.20	19.88	12.38	9.32
Maximum	36.02	36.92	18.89	21.46
Standard Deviation	3.88	5.37	3.09	2.76

Summary statistics for these categorized expenses are provided in Table A.6.

To identify how different categories of distribution expenses are affected by growth, we adapt the univariate regression that includes a fixed effect for the utility (column 5 in Table 3) so that the dependent variable is computed using figures from each of the four categories, instead of the aggregate distribution capital cost data. Table A.7 describes the results of the disaggregated-cost fixed effects regression.

The regression estimates that per-kW spending on conductors increases by $0.29 when the growth rate of system capacity increases by one percentage point. By comparison, spending on load- and customer-related equipment each increase by only $0.13–0.15/kW in response to a one percentage point increase in growth rate. In a scenario where peaks increase but the number of customers and their locations stay the same, one may expect that spending on load and conductors will increase while spending on access and customers stays the same.

Table A.7
Results from the regression that includes a fixed effect for the utility (column 5 in Table 3), applied to disaggregated distribution capital expenses. The results indicate that capital spending on conductors is significantly more sensitive to the growth rate of peak capacity than other categories. The intercept is computed by separately calculating the means of the fixed effects for year and utility and adding these together. Values in parentheses are the standard errors clustered by utility.

	Annual Per-kW Distribution Capital Costs			
	Load	Conductors	Access	Customers
Intercept	6.8***	7.8***	5.0***	3.7***
	(0.3)	(0.2)	(0.2)	(0.1)
Growth	0.13**	0.29**	0.14	0.15***
	(0.07)	(0.12)	(0.08)	(0.05)
R^2	0.014	0.048	0.018	0.029
Adjusted R^2	−0.139	−0.100	−0.132	−0.121
Observations	808	808	808	808
Year Fixed Effects	X	X	X	X
Utility Fixed Effects	X	X	X	X

Note: *p<0.1; **p<0.05; ***p<0.01.

Appendix B. Alternative estimates of the growth rate

In the body of this paper, the growth rate of system capacity, $Growth_{i,t}$, is estimated empirically as the compounding growth rate of

[25] The "Load" category includes substation equipment (including batteries) and line transformers. The "Conductors" category includes capital investments for overhead and underground wires. The "Access" category includes physical infrastructure required to reach a customer, including structures, poles, towers, fixtures, conduit, and land rights. "Customer" expenses include meters, services, customer installations, and leased property on customer premises. Lighting, which represents less than 3% of a typical utility's annual capital expenditures, is omitted.

a utility's proven distribution system capacity, $C_{i,t}$, computed using a 5-year rolling window. Because a utility's proven capacity only increases in years that set new record peaks, $C_{i,t}$ is systematically biased to underestimate the distribution system's actual peak capacity in years with milder weather. Consequently, using a very narrow time window to estimate the growth rate will produce estimates of zero in the years when the distribution system is not stressed to its capacity, even if the utility is actively expanding capacity. Conversely, using a wider window is inherently less precise: an excessively wide window may cause the (non-zero) growth rate in a given year to be biased down by including several years of low load-growth in the rolling window. The aggregate effect is that there will be less observed variation in the growth rate for a given utility. The choice of a 5-year rolling window is intended to serve as a compromise, dampening the effects of inter-annual volatility in observed peaks without flattening out any observable variation in the growth rate for a given utility.

This section presents the results of two regressions applied using two alternative estimates of $Growth_{i,t}$, computed using a 3-year rolling window and a 7-year rolling window. These results are then compared to the original estimates that use a 5-year rolling window. All three estimates of the growth rate are described by Eq. (5), where n is the width of the rolling window in years.

$$Growth_{i,t} = \left[\frac{C_{i,t+\frac{n-1}{2}}}{C_{i,t-\frac{n-1}{2}}}\right]^{\frac{1}{n-1}} - 1, \quad C_{i,t} \geq C_{i,t-1} \tag{5}$$

Table B.8 provides summary statistics of the estimated growth rates. The growth rate computed over a 3-year rolling window, $Growth^3_{i,t}$, has more than 25% of estimated observations equaling 0%. $Growth^3_{i,t}$ also has a significantly higher maximum observation than $Growth^5_{i,t}$ or $Growth^7_{i,t}$, likely because the effects of multiple years of capacity growth are observed in one or two years when the proven capacity jumps, which happens whenever the distribution system reaches its design conditions.

Table B.9 summarizes the regression results. In columns (1)–(3), we use the multivariate regression that controls for the three utility attributes discussed in Section 3. In columns (4)–(6), we use the regression that includes a fixed effect for the utility. Columns (1) and (4) compute $Growth$ using a 3-year rolling window, columns (2) and (5) compute $Growth$ using a 5-year rolling window (the estimate used throughout the paper), and columns (3) and (6) compute $Growth$ using a 7-year rolling window.

The estimated growth rate coefficients in columns (1) and (4) are significantly smaller than the estimates in columns (2), (3), (5), and (6), indicating that the regressions that use a 3-year window to compute $Growth_{i,t}$ attribute a smaller proportion of capital investments in the distribution system to capacity growth than regressions that use a wider window. One explanation is that because the growth rate is computed over a narrower window than the other estimates, growth in proven capacity (which is a function of both the actual system capacity and the weather) is not always observed in the same years that growth-related investments occur. In other words, even if the utility is actively expanding capacity to accommodate load growth, that growth may not be observed immediately if the network is not regularly stressed to its design conditions.

The estimated growth rate coefficient in columns (3) and (6), which use a 7-year rolling window, are similar to those estimated using a 5-year rolling window. The estimate in column (3) has a higher standard error, which renders the estimated coefficient insignificant. The estimated growth rate coefficient for the regression that uses a 7-year rolling window and includes a fixed effect for the utility is similar to the coefficients produced using a 5-year rolling window.

As discussed earlier, proven capacity is an imperfect measure of the actual distribution system capacity, especially if one is interested in estimating changes in capacity between years. Much of the uncertainty discussed herein would be removed if comprehensive infrastructure data were made available for a broad sample of utilities. Until such a time, these estimates may provide a useful heuristic for those interested in modeling electric distribution system expansion.

Table B.8
Summary statistics of the compounding annual growth rate, estimated using a 3-year, 5-year, and 7-year rolling window. The growth rate estimated over a 3-year window has a significantly higher standard deviation than the 5-year and 7-year estimates.

	$Growth^3$	$Growth^5$	$Growth^7$
Minimum	0.00%	0.00%	0.00%
5%	0.00%	0.00%	0.00%
25%	0.00%	0.67%	0.92%
Median	1.05%	1.64%	1.65%
Mean	1.82%	1.86%	1.83%
75%	3.09%	2.69%	2.53%
95%	6.15%	4.82%	4.39%
Maximum	13.91%	8.30%	6.21%
Standard Deviation	2.20%	1.53%	1.29%
Observations	808	808	606

Table B.9
Regression results using three different specifications for the growth rate. Columns (1)-(3) use the multivariate regression with controls. Columns (4)-(6) use the regression with fixed effects for the utility. Columns (1) and (4) summarize the regression results where $Growth_{i,t}$ is computed using a 3-year rolling window, columns (2) and (5) summarize the results where $Growth_{i,t}$ is computed using a 5-year rolling window (the specification used throughout the body of the paper), and columns (3) and (6) summarize the results where $Growth_{i,t}$ is computed using a 7-year rolling window.

	Annual Per-kW Distribution Capital Costs					
	(1)	(2)	(3)	(4)	(5)	(6)
Intercept	14.39***	14.30***	14.24***	25.13***	23.86***	24.69***
	(0.99)	(1.02)	(0.87)	(0.57)	(0.49)	(0.36)
$Growth^3$	0.32			0.23*		
	(0.21)			(0.12)		
$Growth^5$		0.74**			0.76***	
		(0.35)			(0.20)	
$Growth^7$			0.70			0.78***
			(0.55)			(0.28)
$Underground$	0.59***	0.57***	0.59***			
	(10.97)	(10.83)	(10.92)			
$\log(Density)$	−1.72***	−1.69***	−1.82***			
	(0.66)	(0.65)	(0.65)			
$Residential$	0.24**	0.23**	0.24**			
	(10.52)	(10.75)	(11.30)			
R^2	0.366	0.373	0.386	0.019	0.019	0.044
Adjusted R^2	0.358	0.365	0.376	−0.133	−0.133	−0.159
Observations	808	808	606	808	808	606
Year Fixed Effects	X	X	X	X	X	X
Utility Fixed Effects				X	X	X

Note: *p<0.1; **p<0.05; ***p<0.01.

Appendix C

See Table C.10.

Table C.10
List of Utilities.

Utility	State	Region	C_i	$Growth_i$	$Underground_i$	$Density_i$	$Residential_i$
Alabama Power Company	AL	SE	11,511	1.5%	8.3%	21.6	32.6%
Alaska Electric Light and Power Company	AK	WE	64	2.0%	20.4%	1.5	42.0%
ALLETE (Minnesota Power)	MN	MW	1,515	1.4%	18.1%	26.3	11.1%
Appalachian Power Company	OH	MW	6,974	2.7%	9.1%	28.4	38.8%
Arizona Public Service Company	AZ	WE	6,501	4.7%	41.5%	19.1	45.4%
Atlantic City Electric Company	DE	MA	2,726	3.4%	10.8%	114.7	44.5%
Avista Corporation	WA	WE	1,734	0.7%	18.4%	8.7	40.6%
Baltimore Gas and Electric Company	MD	MA	6,808	1.6%	31.5%	309.5	40.0%
Black Hills Power, Inc.	SD	MW	398	1.9%	17.7%	2.1	29.5%
Central Hudson Gas & Electric Corporation	NY	MA	1,154	3.3%	10.0%	65.0	43.2%
Central Maine Power Company	ME	NE	1,633	1.8%	4.6%	24.5	23.0%
Cleco Power LLC	LA	SW	1,915	2.0%	8.7%	23.5	39.6%
Cleveland Electric Illuminating Company	OH	MW	4,559	0.8%	20.4%	245.1	27.4%
Commonwealth Edison Company	IL	MW	22,251	1.6%	33.6%	155.2	30.6%
Connecticut Light and Power Company	CT	NE	5,272	1.6%	21.5%	131.7	42.2%
Consolidated Water Power Company	WI	MW	231	0.3%	18.8%	0.4	0.6%
Consumers Energy Company	MI	MW	8,277	1.6%	11.0%	30.6	35.6%
Dayton Power and Light Company	OH	MW	3,176	0.6%	14.4%	55.5	35.1%
Delmarva Power & Light Company	DE	MA	3,876	3.3%	19.3%	52.7	37.0%
DTE Electric Company	MI	MW	11,764	0.8%	18.0%	45.1	33.3%
Duke Energy Carolinas, LLC	NC	SE	17,003	0.7%	18.7%	44.8	32.8%
Duke Energy Florida, LLC	FL	SE	9,698	2.8%	19.0%	39.7	50.5%
Duke Energy Indiana, LLC	IN	MW	5,999	1.8%	15.4%	19.4	30.7%
Duke Energy Kentucky, Inc.	OH	MW	828	2.2%	17.3%	265.8	35.9%
Duke Energy Ohio, Inc.	OH	MW	5,250	0.8%	19.6%	197.3	34.3%
Duke Energy Progress, LLC	NC	SE	11,407	1.8%	18.9%	22.2	36.5%
Duquesne Light Company	PA	MA	2,897	1.6%	17.0%	417.2	28.4%
El Paso Electric Company	TX	SW	1,447	0.6%	22.7%	17.1	30.2%
Emera Maine	ME	NE	305	0.4%	2.9%	2.9	36.2%
Empire District Electric Company	MO	MW	1,062	2.3%	11.2%	115.0	40.4%
Entergy Arkansas, LLC	AR	SE	6,889	0.8%	8.7%	10.0	35.8%
Entergy Mississippi, LLC	MS	SE	3,216	1.3%	5.7%	12.1	39.5%
Entergy New Orleans, LLC	LA	SW	1,276	0.1%	29.0%	674.2	33.5%
Fitchburg Gas and Electric Light Company	NH	NE	98	1.6%	10.4%	6.2	33.4%
Florida Power & Light Company	FL	SE	20,461	2.7%	28.9%	130.1	52.9%
Georgia Power Company	GA	SE	15,865	2.5%	20.8%	24.9	29.4%
Green Mountain Power Corporation	VT	NE	364	2.2%	14.1%	7.4	29.2%
Gulf Power Company	FL	SE	2,459	2.0%	10.4%	40.9	47.2%
Idaho Power Company	ID	WE	2,996	1.3%	18.0%	6.2	34.2%
Indiana Michigan Power Company	OH	MW	4,778	0.0%	15.7%	66.8	30.2%
Indianapolis Power & Light Company	IN	MW	3,025	1.0%	22.8%	466.3	34.2%
Jersey Central Power & Light Company	OH	MW	6,004	3.1%	15.2%	184.6	43.4%
Kansas City Power & Light Company	MO	MW	3,549	1.5%	29.8%	151.6	35.3%
Kansas Gas and Electric Company	KS	MW	2,374	0.4%	16.4%	12.6	31.4%
Kentucky Power Company	KY	MW	1,636	2.5%	1.9%	28.8	34.7%
Kentucky Utilities Company	KY	MW	3,996	2.2%	6.3%	75.0	34.3%
Kingsport Power Company	OH	MW	432	2.4%	9.4%	23.5	35.4%
Lockhart Power Company	SC	SE	80	0.6%	0.7%	5.8	32.9%
Louisville Gas and Electric Company	KY	MW	2,679	1.2%	20.1%	323.7	33.8%
Madison Gas and Electric Company	WI	MW	715	1.6%	38.6%	214.1	25.7%
Metropolitan Edison Company	OH	MW	2,713	2.9%	11.9%	87.3	37.4%
MidAmerican Energy Company	IA	MW	3,964	1.4%	15.3%	14.0	29.4%
Mississippi Power Company	MS	SE	2,593	0.5%	6.9%	9.4	23.9%
Monongahela Power Company	OH	MW	2,062	1.4%	3.8%	19.0	29.4%
Mt. Carmel Public Utility Company	IL	MW	34	0.1%	1.8%	34.6	36.5%
Nevada Power Company	NV	WE	5,021	4.3%	43.0%	93.2	42.1%
New York State Electric & Gas Corporation	NY	MA	2,752	3.1%	7.8%	28.0	41.9%
Northern Indiana Public Service Company	IN	MW	3,089	1.3%	14.8%	39.1	19.8%
Northern States Power Company - MN	MN	MW	8,211	3.1%	33.0%	34.7	28.3%
Northwestern Wisconsin Electric Company	WI	MW	36	3.0%	20.4%	3.3	45.8%
NSTAR Electric Company	MA	NE	3,575	4.4%	43.2%	115.4	28.1%
Ohio Edison Company	OH	MW	6,616	1.2%	14.9%	75.5	34.5%
Ohio Power Company	OH	MW	6,642	0.0%	8.7%	19.8	26.3%
Oklahoma Gas and Electric Company	OK	SW	5,897	2.1%	22.1%	17.0	34.6%
Orange and Rockland Utilities, Inc.	NY	MA	1,437	3.6%	16.9%	98.8	37.1%
Pacific Gas and Electric Company	CA	WE	18,977	2.0%	29.5%	44.7	35.6%
PacifiCorp	OR	WE	8,923	1.7%	18.5%	6.5	29.0%
Pennsylvania Electric Company	OH	MW	2,812	2.1%	9.4%	18.7	31.1%
Pennsylvania Power Company	OH	MW	1,036	2.0%	13.9%	57.3	34.9%

(continued on next page)

Table C.10 (*continued*).

Utility	State	Region	C_i	$Growth_i$	$Underground_i$	$Density_i$	$Residential_i$
Pioneer Power and Light Company	WI	MW	7	2.2%	29.6%	12.9	72.3%
Portland General Electric Company	OR	WE	4,073	0.0%	23.0%	92.8	39.8%
Potomac Edison Company	OH	MW	3,050	3.0%	20.1%	49.7	39.3%
Potomac Electric Power Company	DC	MA	6,472	2.0%	41.6%	679.7	29.2%
PPL Electric Utilities Corporation	PA	MA	7,198	1.6%	13.1%	79.1	36.9%
Public Service Company of Colorado	CO	SW	6,383	3.6%	37.7%	45.6	31.3%
Public Service Company of New Hampshire	NH	NE	1,614	2.3%	9.6%	26.1	37.4%
Public Service Company of New Mexico	NM	SW	1,648	4.8%	30.1%	58.9	32.7%
Public Service Company of Oklahoma	OK	SW	3,952	1.3%	13.5%	8.2	34.0%
Public Service Electric and Gas Company	NJ	MA	10,432	1.7%	23.5%	811.3	30.2%
Puget Sound Energy, Inc.	WA	WE	4,847	0.1%	35.8%	43.7	49.5%
Rochester Gas and Electric Corporation	NY	MA	1,596	2.3%	33.8%	96.0	37.2%
Rockland Electric Company	NY	MA	447	2.7%	21.1%	232.3	45.1%
Sierra Pacific Power Company	NV	WE	1,660	1.8%	28.0%	4.4	25.5%
Southern California Edison Company	CA	WE	20,989	1.8%	31.8%	59.3	32.7%
Southern Indiana Gas and Electric Company	IN	MW	1,249	1.8%	16.7%	54.3	27.6%
Southwestern Electric Power Company	LA	SW	4,711	1.1%	12.7%	13.7	32.0%
Southwestern Public Service Company	TX	SW	4,600	1.9%	9.4%	4.1	20.4%
Superior Water, Light and Power Company	WI	MW	93	2.7%	13.0%	97.2	14.7%
Tampa Electric Company	FL	SE	3,914	2.5%	19.2%	271.9	45.1%
Toledo Edison Company	OH	MW	2,146	1.3%	15.9%	73.0	22.8%
Tucson Electric Power Company	AZ	WE	2,126	4.3%	28.3%	240.7	40.0%
Union Electric Company	MO	MW	8,459	0.4%	18.0%	31.9	36.6%
United Illuminating Company	CT	NE	1,350	1.9%	20.5%	143.6	38.8%
Upper Peninsula Power Company	MI	MW	151	0.6%	13.4%	2.0	35.6%
Virginia Electric and Power Company	VA	SE	16,618	1.1%	28.3%	59.2	37.5%
West Penn Power Company	OH	MW	3,705	1.9%	7.3%	39.7	34.4%
Western Massachusetts Electric Company	MA	NE	797	1.5%	29.4%	39.3	37.4%
Wheeling Power Company	OH	MW	322	3.6%	12.1%	27.9	21.5%
Wisconsin Electric Power Company	WI	MW	6,261	0.9%	35.2%	50.2	28.5%
Wisconsin Power and Light Company	WI	MW	2,775	2.0%	16.8%	21.3	32.8%
Wisconsin Public Service Corporation	WI	MW	2,095	3.6%	12.8%	19.4	27.6%

Note: reported value for C_i, $Growth_i$, $Underground_i$, $Density_i$, and $Residential_i$ is the mean of that value for utility i from 2000–2007.

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