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The Full Cost of Electricity (FCe-)

Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities

PART OF A SERIES OF WHITE PAPERS

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THE FULL COST OF ELECTRICITY is an interdisciplinary initiative of the Energy Institute of the University of Texas to identify and quantify the full-system cost of electric power generation and delivery – from the power plant to the wall socket. The purpose is to inform public policy discourse with comprehensive, rigorous and impartial analysis.

The generation of electric power and the infrastructure that delivers it is in the midst of dramatic and rapid change. Since 2000, declining renewable energy costs, stringent emissions standards, low-priced natural gas (post-2008), competitive electricity markets, and a host of technological innovations promise to forever change the landscape of an industry that has remained static for decades. Heightened awareness of newfound options available to consumers has injected yet another element to the policy debate surrounding these transformative changes, moving it beyond utility boardrooms and legislative hearing rooms to everyday living rooms.

The Full Cost of Electricity (FCe-) study employs a holistic approach to thoroughly examine the key factors affecting the *total direct and indirect costs* of generating and delivering electricity. As an interdisciplinary project, the FCe- synthesizes the expert analysis and different perspectives of faculty across the UT Austin campus, from engineering, economics, law, and policy. In addition to producing authoritative white papers that provide comprehensive assessment and analysis of various electric power system options, the study team developed online calculators that allow policymakers and other stakeholders, including the public, to estimate the cost implications of potential policy actions. A framework of the research initiative, and a list of research participants and project sponsors are also available on the Energy Institute website: energy.utexas.edu

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This paper is one in a series of Full Cost of Electricity white papers that examine particular aspects of the electricity system.

Other white papers produced through the study can be accessed at the University of Texas Energy Institute website:

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Trends in Transmission, Distribution, and Administration Costs for U.S. Investor Owned Electric Utilities

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The FERC data used in this white paper are available for download in Excel format from the data and publication page of http://energy.utexas.edu/the-full-cost-of-electricity-fce/.

ABSTRACT

This paper analyzes the cost of electricity transmission, electricity distribution, and utility administration in the United States. We analyze data reported to the Federal Energy Regulatory Commission (FERC) by investor-owned electric utilities from 1994–2014 using linear regression to understand how the number of customers in a utility's territory, annual peak demand, and annual energy sales affect annual spending related to transmission, distribution, and administration (TD&A). We also compare data provided by FERC for 1994–2014 to historic data for 1960–1992 provided by the Edison Electric Institute to show annual trends in TD&A spending between 1960 and 2014. We find that the number of customers in a utility's territory is the single best predictor for annual TD&A costs. Between 1994 and 2014, the average TD&A cost per customer was \$119/Customer-Year, \$291/Customer-Year, and \$333/Customer-Year, respectively. Total TD&A costs per customer have been roughly constant and equal to \$700–\$800/Customer-Year for much of the past 54 years, but the cost per kWh of energy sold was significantly higher in the 1960s than it is today because the average customer used less than half as much energy annually. Thus, TD&A charges per kWh will increase if kWh energy sales decline in the future unless cost recovery is transitioned to a fixed customer charge or another mechanism not based solely on kWh sales.

1 | INTRODUCTION AND MOTIVATION

There are four principal components of the direct cost of electricity: generation, transmission, distribution, and administrative costs associated with utilities or retail electricity providers. The cost of electricity generation includes the upfront capital cost of electric power plants and any recurring operation and maintenance costs such as the cost of fuel, labor costs for plant operators, and costs associated with routine maintenance. Electricity transmission and distribution costs include the upfront capital cost of land, utility poles, wires, substations, transformers, and other equipment used to deliver electricity. They also include recurring costs for energy consumed by electrical losses in the transmission and distribution systems and other routine operation and maintenance costs. The remaining portion of the direct cost of electricity is comprised of utility administrative costs associated with reading electrical billing meters, managing utility customer accounts, customer service, sales expenses, staff expenses, office buildings, property insurance, and a number of other miscellaneous costs.

While there are a number of sources of information about the cost of various electricity generation technologies [1–4], there is relatively little public information about electricity transmission, distribution, and administrative costs. The U.S. Energy Information Administration approximates electricity transmission and distribution prices per kWh of energy delivered for its Annual Energy Outlook, but does not directly examine what factors influence those prices and the extent to which prices vary between utilities. The academic literature has examined the cost of electricity transmission and distribution and what factors influence those costs [5–7], but most recent work focuses on how distributed generation or other smart grid interventions might affect electric delivery costs without approximating baseline costs in detail [8–10].

In the coming years, it will become increasingly important to distinguish the cost of electricity generation from electricity transmission, distribution, and administration costs. Distributed generation technologies such as rooftop photovoltaic panels, fuel cells, and microturbines enable customers to act as both consumers and producers of energy. Shifting consumers to consumer-producers or "prosumers" disrupts the traditional utility business model, because electricity transmission, distribution, and administration costs are often recovered from a volumetric charge on the amount of kWh of energy consumed. When consumers utilize the utility's system to integrate their own sources of electricity generation and reduce their kWh consumption, it reduces the utility's revenue but does not necessarily reduce the costs for electricity transmission, distribution, and utility administration [11].

To develop information for policymakers, regulators, and the general public, this paper approximates electricity transmission, distribution, and administration costs in the United States and shows what factors influence those costs.

The remainder of this paper is organized as follows: Section 2 introduces the data and methods used to quantify and examine electricity costs; Sections 3–5 analyze electricity transmission, distribution, and administration costs, respectively; Section 6 summarizes total transmission, distribution, and administration costs, and Section 7 discusses our findings and presents some key conclusions. ■

2 | DATA AND METHODS

The quantification of the costs of electricity transmission, distribution, and administration, along with the drivers of those costs, requires data that 1) make a clear distinction between the costs associated with generation, transmission, distribution, and utility administration, 2) represent a sufficient number of utilities to approximate the general character of electricity costs in the United States, and 3) report factors that might influence cost such as the number of utility customers, peak electricity demand, and volumetric electric energy sales.

One dataset that has all three of these characteristics is a database of investor-owned electric utility filings with the Federal Energy Regulatory Commission (FERC). Investor-owned utilities are required to file annual reports (FERC Form 1) with FERC that provide the cost of new infrastructure, operation and maintenance costs, the number of utility customers, peak MW electricity demand, MWh energy sales, and a number of other pieces of information. The filing makes a clear distinction between generation, transmission, distribution, and administration costs. FERC provides a sample of Form 1 on its website, and a freely available database of historic FERC Form 1 filings [12–13].

The FERC Form 1 database includes filings from over 200 utilities from the year 1994 to the present day. While the data span multiple years and are freely available, they are distributed in Microsoft Visual FoxPro format, which has not been supported by Microsoft since 2007 [14]. To access and analyze the data, we read the Microsoft FoxPro database files using the analytics software SAS, and then converted each database file into CSV format [15]. Then, we read the generated CSV files into the R programming package for statistical computing [16]. The remainder of the data organization and analysis discussed in this paper is performed using R.

We organize data entries for annual spending on transmission, distribution, and administration, as well as peak annual demand in MW, total annual energy sales in MWh, and the the total number of utility customers. The following paragraphs specify which entries of FERC Form 1 are read to organize these data.

Annual spending on new capital infrastructure is read from pages 204–207 of FERC Form 1, titled Electric Plant in Service. Annual transmission capital expenditures are recorded from Line 58, Column C - Total Transmission Plant Additions. Likewise, annual distribution capital expenditures are recorded from Line 75, Column C - Total Distribution Plant Additions. Administrative capital expenditures are recorded as the sum of Line 5, Column C - Total Intangible Plant Additions, and Line 99, Column C - Total General Plant Additions.

Operation and maintenance costs associated with transmission, distribution, and administration are read from pages 320–323 of FERC Form 1, titled Electric Operation and Maintenance Expenses. Annual transmission operation and maintenance costs are recorded as the sum of Line 99, Column B - Total Transmission Operation Expenses for Current Year, and Line 111, Column B - Total Transmission Maintenance Expenses for Current Year. Likewise, annual distribution operation and maintenance costs are recorded as the sum of Line 144, Column B - Total Distribution Operation Expenses, and Line 155, Column B - Total Distribution Maintenance Expenses. Administrative operation and maintenance costs are recorded as the sum of four entries: Line 164, Column B - Total Customers Accounts Expenses; Line 171, Column B - Total Customer Service and Information Expenses; Line 178, Column B - Total Sales Expenses; and Line 197, Column B - Total Administrative and General Expenses.

The annual peak demand in MW over the year is read from page 401, titled Monthly Peaks and Output. The monthly peak demand is listed in Lines 29–40, Column D. We record the maximum of these monthly reports during each year as the annual peak demand in MW. The annual energy sales and customer count data come from page 300, Electric Operating Revenues. We record the values provided in Line 2 - Residential Sales, Line

4 - Commercial Sales, Line 5 - Industrial Sales, and Line 10 - Total Sales to Ultimate Consumers. Note that total sales include sales for public street lighting and other sales to public authorities in addition to residential, commercial, and industrial sales for some utilities, so total sales do not always equal the sum of residential, commercial, and industrial sales. For each of these lines, we record the corresponding dollars of revenue (Column B), MWh of energy sold (Column D), and average number of customers over the year (Column F).

We read these data into R and organize the data into a table that contains all reported values for all utilities in the database for the years 1994–2014. To identify any erroneous data points, we examine the year-to-year change in spending, MW demand, MWh energy sales, and total customers for individual utilities. Any outlying year-to-year changes were investigated by examining the corresponding FERC Form 1 filings by hand using the FERC Form 1 Viewer available on FERC's website [13]. Appendix A.1 details corrections made to the raw FERC Form 1 data. We provide the entire FERC Form 1 utility spending database used in this paper on the Full Cost of Electricity website in Excel format [17].

Utility customers are typically billed for electric service with a combination of three different charges: a monthly fixed charge often called a customer charge or meter charge, a volumetric charge on energy consumption in $/kWh, and, in the case of commercial and industrial customers, a charge on instantaneous peak electricity demand over the month levied in $/kW. Thus, we analyze the relationship between transmission, distribution, and administration costs and a utility's total customer count, annual peak power demand, and annual energy sales.

We analyze the relationship between cost predictors (number of utility customers, annual peak demand, annual energy sales sales), and cost outcomes (capital, operation, and maintenance costs) using linear regression [18]. To understand the extent to which we can isolate the independent influence of each of the predictors, we test for collinearity between the predictors by computing the Pearson correlation coefficient between individual sets of predictors. The Pearson correlation coefficient varies between a value of 0 and 1, with a value of 1 indicating perfect correlation and a value of 0 indicating no correlation. The Pearson correlation coefficients between each of the predictors considered are given in Table 1.

TABLE 1:

We compute the Pearson correlation coefficient between each of the cost predictors considered to test for collinearity. All three cost predictors are found to be highly collinear.

	Total Customers	Total MWh Sales	Peak MW Demand
Total Customers	1	0.922	0.937
Total MWh Sales	0.922	1	0.986
Peak MW Demand	0.937	0.986	1

Because each of the cost predictors have a high correlation coefficient, the dataset is highly collinear, and it is not possible to isolate the influence of each of the predictors on transmission, distribution, and administration costs. Thus, we perform separate regressions on each of the cost predictors and use the extent to which they can predict cost outcomes to understand their relative influence.

After the relationship between cost outcomes and cost predictors is established using data from the FERC Form 1 database, we analyze how utility transmission, distribution, and administration costs have varied over time. We use FERC Form 1 data to show variation in costs during the years 1994–2014. To expand the period of time considered, we compare these data to aggregate investor-owned utility data available from the Edison Electric Institute for the years 1960–1992 [19]. Note that these data include the total annual spending, customers, demand, and energy sales for all U.S. investor owned utilities, but do not include data for individual utilities. Thus, Edison Electric Institute data are not used in the regression analysis, and are only used to show how average costs have varied over time.

The following sections show the relationship between transmission, distribution, and administrative capital, operation, and maintenance costs and a utility's customer count, annual peak demand, and annual energy sales. Each cost outcome is analyzed using linear regression, and then the variation in costs between the years 1960–2014 is shown. ■

3 | ELECTRICITY TRANSMISSION COSTS

3.1 Relationship Between Transmission System Capital Costs and Utility Customers, Demand, and Energy Sales

The first cost outcome we analyze is annual capital spending on new electricity transmission infrastructure. These costs include the cost of land and land use rights, substation equipment, transmission towers, conductors, and a number of other capital costs associated with electricity transmission. A complete breakdown of these costs is available on Page 206 of FERC Form 1 [12]. We use linear regression to analyze the reported annual capital spending on transmission infrastructure for years 1994–2014 versus the number of utility customers, annual energy sales, and peak electric demand during the same years. All costs are adjusted for inflation to real 2015 dollars using the Consumer Price Index released by the U.S. Bureau of Labor Statistics [20]. Table 2 presents results for the regressions on total utility customers, annual energy sales, and annual peak demand. Each regression considers 2647 individual utility reports between the years 1994–2014, or an average of 126 utility reports per year. We show the raw data and corresponding regression lines in Figures A1–A3 in the Appendix.

We find that the annual spending on new electricity transmission capital infrastructure does not scale strongly with any of the predictors considered. The average cost across the dataset of U.S. investor-owned electric utility reports from 1994–2014 is $75 per customer per year, $13 per kW of peak demand per year, and 0.3 ¢/kWh of electric energy sold, with all costs measured in real 2015 dollars.

3.2 Variation in Transmission System Capital Costs Over Time

With the correlation between transmission system capital costs and the number of customers in a utility's territory, annual peak demand, and annual energy sales established, we examine how transmission system capital costs have varied over time. We use data from the FERC Form 1 database to show the average cost of new transmission system capital infrastructure and the variation in costs amongst U.S. investor-owned electric utilities for the years 1994–2014. We also use aggregate investor-owned utility financial data from the Edison Electric Institute to show the average cost of new transmission infrastructure from the years 1960–1992 (note that data is not available for individual utilities during these years) [19].

Figures 1–Figure 3 show the historic variation in transmission system capital infrastructure costs for the years 1960–2014 per utility customer, kW of peak demand, and kWh of energy sold, respectively. The average cost for all U.S. investor-owned utilities is shown for 1960–2014 and the middle 80% of individual utility costs is shown for 1994–2014, the years for which FERC provides data. Note that data for the year 1993 are not available.

TABLE 2

We perform separate linear regressions analyzing the relationship between the outcome variable annual transmission capital spending (in real 2015 dollars) and three predictor variables. There is not a strong relationship between transmission infrastructure spending and any of the predictors considered.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	$75/Customer-Year	$2.2/Customer-Year	$<2 \times 10^{-16}$	0.308
Annual Peak Demand	$13/kW-Year	$0.4/kW-Year	$<2 \times 10^{-16}$	0.265
Annual Energy Sales	0.3 ¢/kWh	0.010 ¢/kWh	$<2 \times 10^{-16}$	0.250

FIGURE 1

The average cost of new transmission system capital infrastructure was less than $100/Customer-Year and roughly flat during the years 1985–2000, but in recent years transmission capital costs have increased to levels not seen since the 1960s and 1970s.

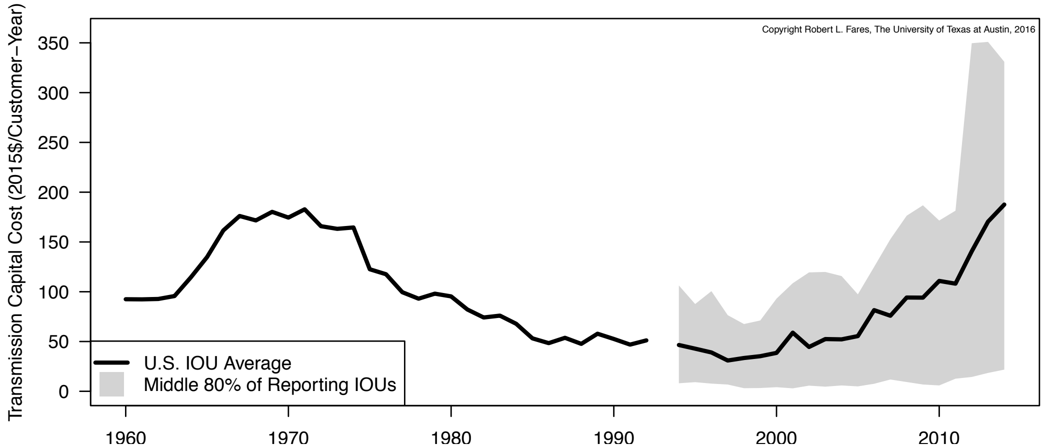


FIGURE 2

The average cost of new transmission system capital infrastructure peaked in the late 1960s, and declined until the late 1990s. Since then, transmission capital costs per kW have increased but have not exceeded the costs observed during the 1960s and 1970s.

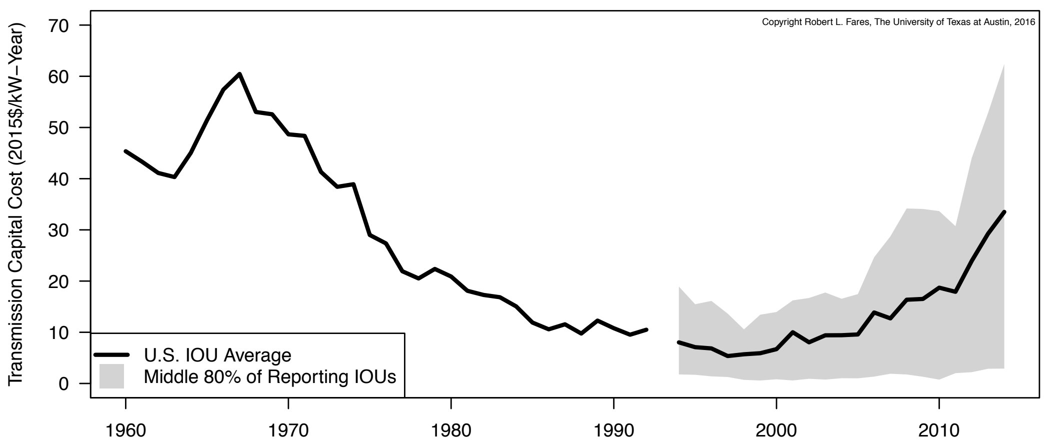
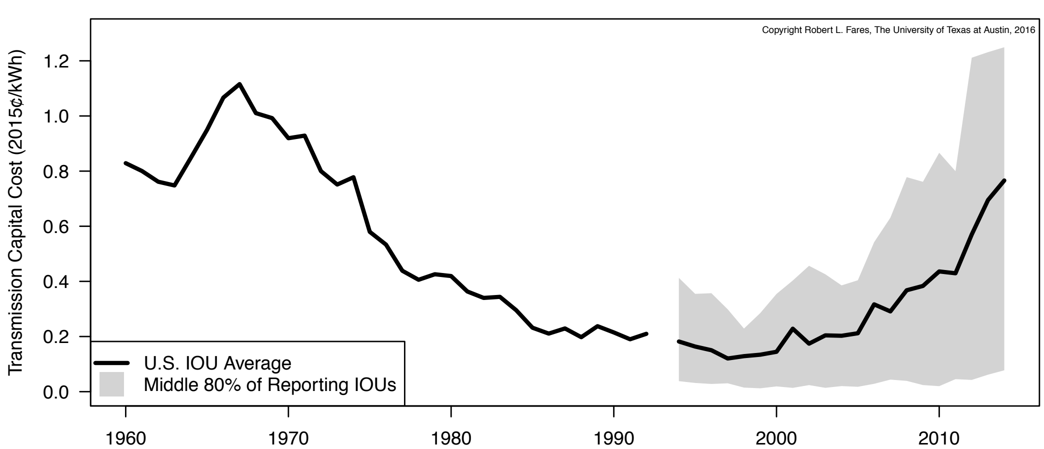


FIGURE 3

The average cost of new transmission system capital infrastructure peaked in the late 1960s, and declined until the late 1990s. While transmission capital costs have increased since the 1990s, the average annual cost per kWh is smaller than the costs observed in the 1960s and 1970s.



Transmission capital costs peaked in the 1960s and 1970s, when a ``historic'' build out of the transmission system occurred in response to major base load generator additions and North American Electric Reliability Corporation (NERC)-coordinated construction of regional ties between major utilities to improve reliability in response to blackouts [21]. Since the late 1990s, transmission capital costs have increased to replace aging infrastructure, maintain reliability, facilitate competitive power markets, and support renewable energy [21].

3.3 Relationship Between Transmission System Operation and Maintenance Costs and Utility Customers, Demand, and Energy Sales

The next cost variable we consider is annual spending on operation and maintenance of the electricity transmission system. These costs include operation and supervision engineering, load dispatching, standards development, routine maintenance, and a variety of other recurring costs associated with electricity transmission. A complete breakdown of transmission-related operation and maintenance costs is provided on Page 321 of FERC Form 1 [12]. We adjust all operation and maintenance expenses for inflation according to the Consumer Price Index [20]. Then, we perform regression analyses for annual transmission operation and maintenance costs versus the number of customers in a utility's territory, annual peak demand, and annual energy sales. The results of these analyses are given in Table 3. Figures A4–A6 in Appendix A.2.2 show the raw data and the corresponding regression lines.

3.4 Variation in Transmission System Operation and Maintenance Costs Over Time

As was done for transmission system capital costs, we show the variation in transmission system operation and maintenance costs over time. We use data from the FERC Form 1 database to show the average cost of transmission system operation and maintenance and the cost variation between U.S. investor-owned electric utilities for the years 1994–2014. No data is available prior to 1994, because Edison Electric Institute does not distinguish transmission system operation and maintenance costs from distribution system operation and maintenance costs, but rather reports total transmission and distribution operation and maintenance costs [18].

Figures 4–6 show the variation in transmission system operation and maintenance costs from the years 1994–2014 versus the number of customers in a utility's territory, annual peak demand, and annual energy sales, respectively. While average costs have not changed significantly since 1994, there has been growing variation in the costs for individual utilities.

3.5 Relationship Between Total Transmission System Costs and Utility Customers, Demand, and Energy Sales

To show the total (capital, operation, and maintenance) costs associated with electricity transmission, we repeat the regression analyses with total annual transmission costs as the outcome variable and the number of utility customers, peak annual demand, and annual

TABLE 3

We perform separate linear regressions analyzing the relationship between annual transmission system operation and maintenance costs (in real 2015 dollars) and three predictor variables. The results of the regressions for each predictor considered are given.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	\$45/Customer-Year	\$1.0/Customer-Year	$< 2 \times 10^{-16}$	0.416
Annual Peak Demand	\$8/kW-Year	\$0.2/kW-Year	$< 2 \times 10^{-16}$	0.367
Annual Energy Sales	0.17 ¢/kWh	0.005 ¢/kWh	$< 2 \times 10^{-16}$	0.337

FIGURE 4

Transmission system operation and maintenance costs were approximately $40–$80/Customer-Year on average from the years 1994–2014, but some utilities have reported higher than average costs in recent years.

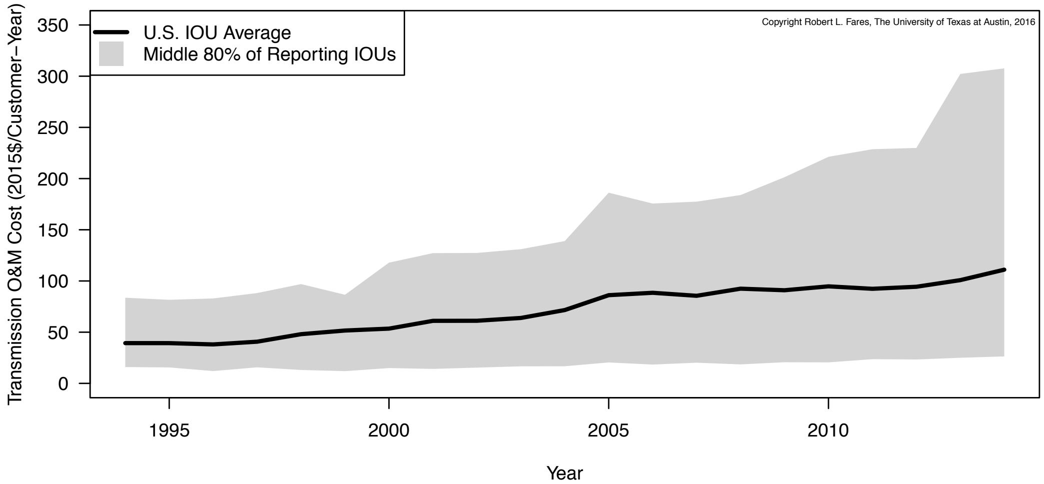


FIGURE 5

Transmission system operation and maintenance costs were approximately $6–$14/kW-Year on average from the years 1994–2014, but some utilities have reported higher than average costs in recent years.

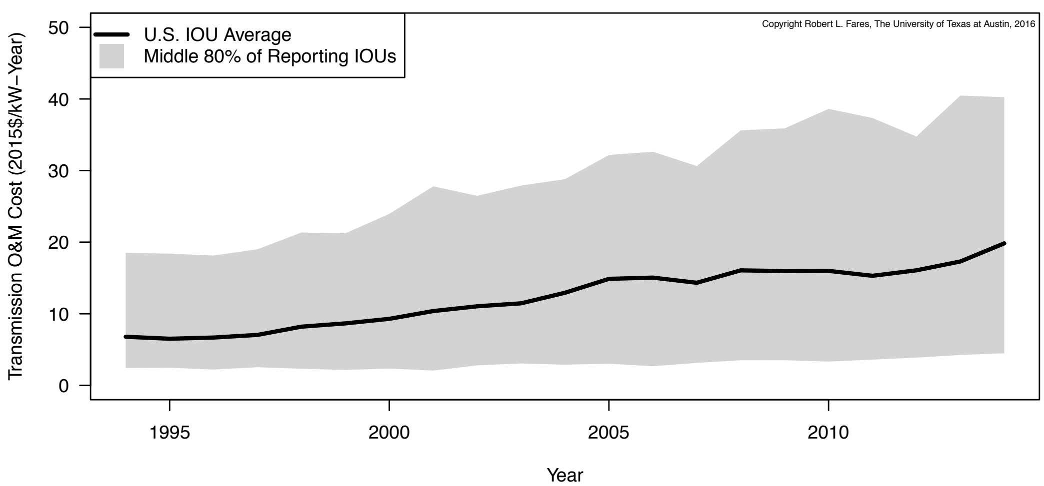


FIGURE 6

Transmission system operation and maintenance costs were approximately 0.1–0.3 ¢/kWh on average from the years 1994–2014, but some utilities have reported higher than average costs in recent years.

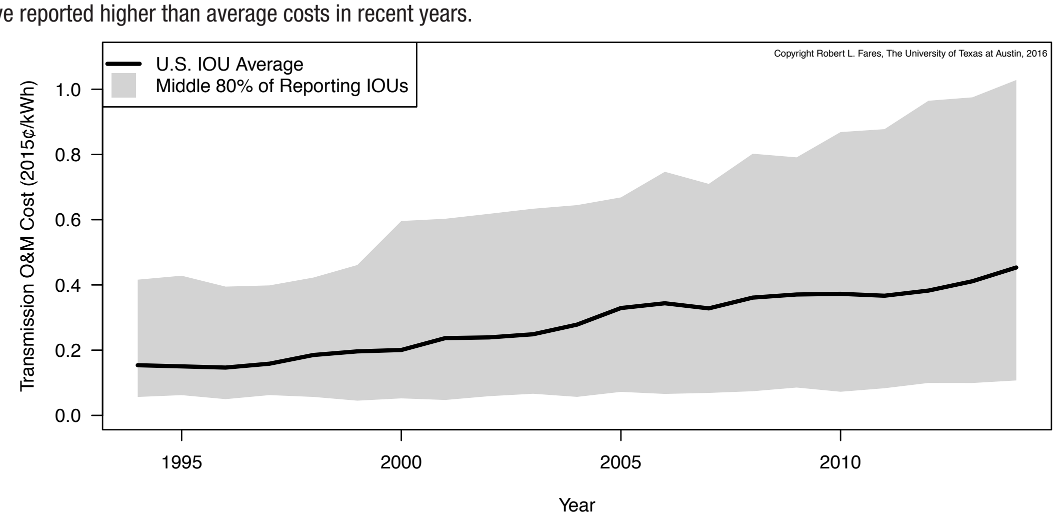


TABLE 4

We perform separate linear regressions analyzing the relationship between total annual transmission system costs (in real 2015 dollars) and three predictor variables. The results of the regressions for each predictor considered are given.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	$119/Customer-Year	$2.6/Customer-Year	$< 2 \times 10^{-16}$	0.459
Annual Peak Demand	$21/kW-Year	$0.5/kW-Year	$< 2 \times 10^{-16}$	0.399
Annual Energy Sales	0.47 ¢/kWh	0.012 ¢/kWh	$< 2 \times 10^{-16}$	0.373

energy sales as the predictor variables. The results of these analyses are given in Table 4. The raw data and corresponding regression lines are given in Figures A7–A9 in Appendix A.2.3.

The results for total annual transmission system costs are similar to the results observed when transmission system capital costs and transmission system operation and maintenance costs are analyzed separately. The number of customers in a utility's territory is the best predictor for annual transmission costs, but none of the predictors accurately predict annual transmission costs.

3.6 Variation in Total Transmission System Costs Over Time

We use data from the FERC Form 1 database to show the average cost of transmission system capital, operation, and maintenance and the cost variation between U.S. investor-owned electric utilities for the years 1994–2014. Because the Edison Electric Institute only reports combined operation and maintenance cost for transmission and distribution, we only show average transmission system capital costs for the years 1960–1992 [19]. Figures 7–9 show transmission costs for the years 1960–2014 normalized by the number of customers in a utility's territory, annual peak demand in kW, and annual energy sales in kWh, respectively. The total costs associated with electricity transmission have been increasing since the late 1990s. The average cost increased from $82/Customer-Year in 1999 to $227/Customer-Year in 2014. This increase is equivalent to an increase from $14/kW-Year to $40/kW-Year or 0.3 ¢/kWh to 0.9 ¢/kWh from 1999–2014. ■

FIGURE 7

The average cost of transmission system capital infrastructure, operation, and maintenance (in real 2015 dollars) increased from $82/Customer-Year in 1999 to $227/Customer-Year in 2014. The cost for transmission capital infrastructure only during 1960–1992 is shown for reference.

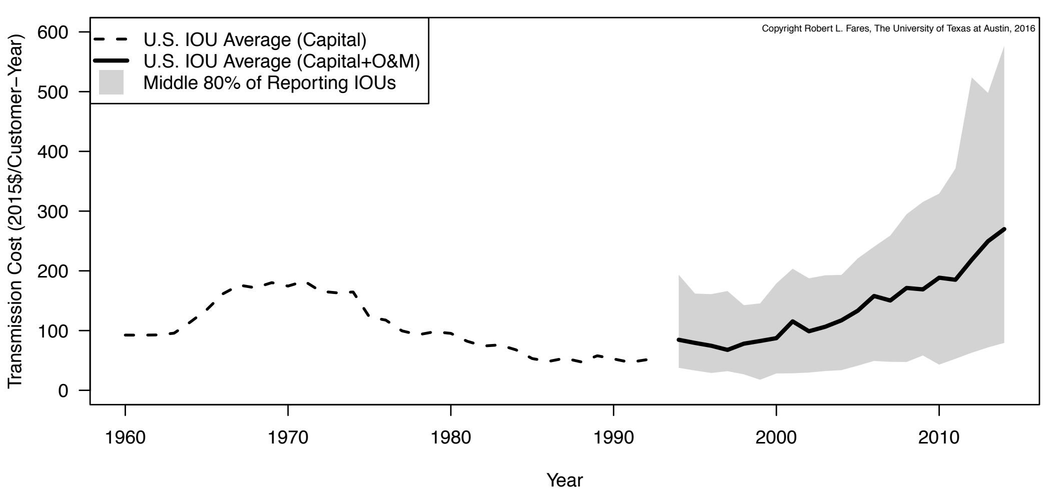


FIGURE 8

The average cost of transmission system capital infrastructure, operation, and maintenance (in real 2015 dollars) increased from $14/kW-Year in 1999 to $40/kW-Year in 2014. The cost for transmission capital infrastructure only during 1960–1992 is shown for reference.

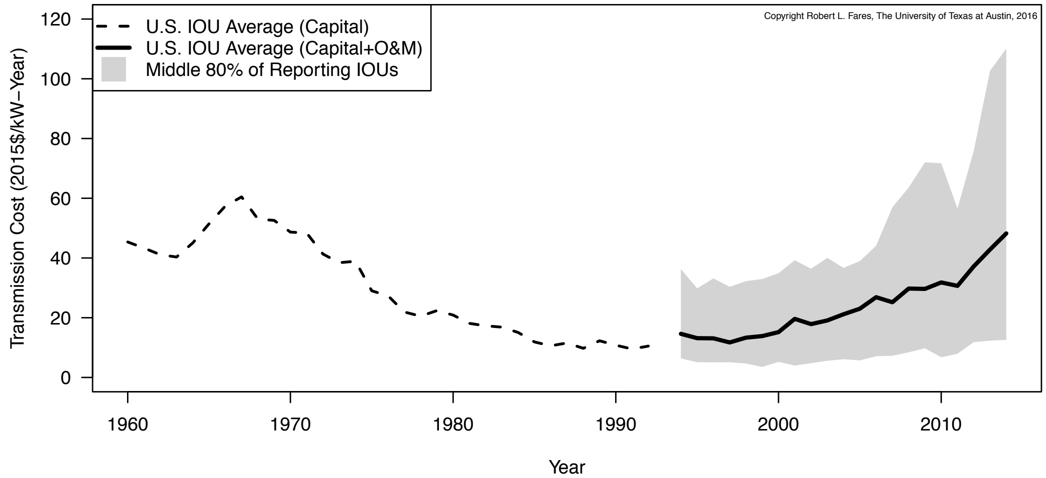
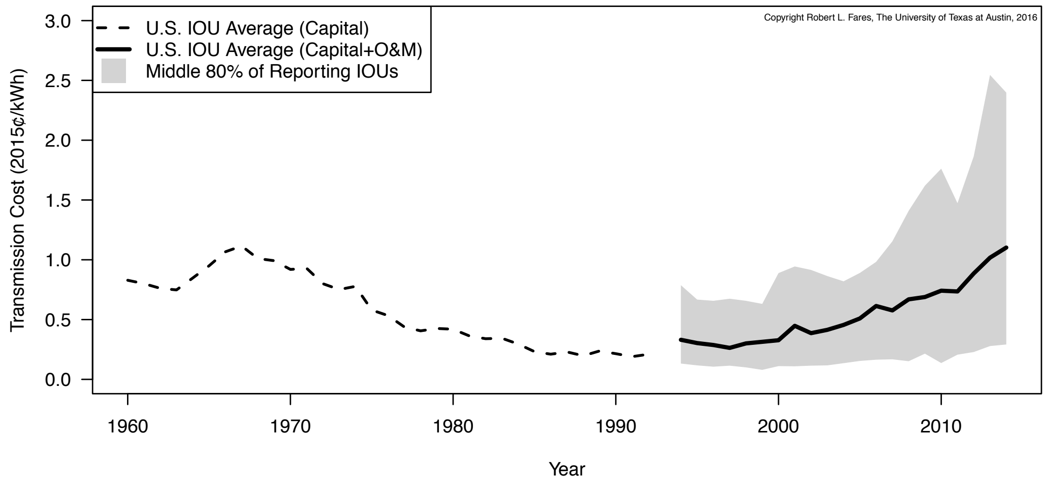


FIGURE 9

The average cost of transmission system capital infrastructure, operation, and maintenance (in real 2015 dollars) increased from 0.3 ¢/kWh in 1994 to 0.9 ¢/kWh in 2014. The cost for transmission capital infrastructure only during 1960–1992 is shown for reference.



4 | ELECTRICITY DISTRIBUTION COSTS

4.1 Relationship Between Distribution System Capital Costs and Utility Customers, Demand, and Energy Sales

Distribution system capital costs include the cost of land and land use rights, substation equipment, utility poles, conductors, transformers, customer meters, and a number of other capital costs associated with electricity distribution. A complete breakdown of these costs is available on Page 206 of FERC Form 1 [12]. We use linear regression to analyze the reported capital spending on distribution infrastructure for years 1994–2014 versus the number of utility customers, annual energy sales, and peak electric demand during the same years. All costs are adjusted for inflation to real 2015 dollars using the Consumer Price Index released by the U.S. Bureau of Labor Statistics [20]. Table 5 presents results for the regressions on total utility customers, annual energy sales, and annual peak demand. Figures A10–A12 in Appendix A.3.1 show the raw data and the corresponding regression lines. Each regression considers 2910 individual utility reports between the years 1994–2014, or an average of 139 utility reports per year.

We find that the number of customers in a utility's territory is the single best predictor for annual spending on new distribution system capital infrastructure. The average infrastructure cost for U.S. investor-owned utilities during the years 1994–2014 was $189 per utility customer per year, with all costs measured in real 2015 dollars.

4.2 Variation in Distribution System Capital Costs Over Time

With the relationship between the cost of distribution system capital infrastructure versus the number of utility customers, annual peak demand, and annual energy sales established, the next item we analyze is the variation in the cost of distribution capital infrastructure over time. We use data from the FERC Form 1 database to show the variation in costs between U.S. investor-owned electric utilities for the years 1994–2014. We also show the average cost of distribution capital infrastructure during years 1960–1992 using aggregated data for all U.S. investor-owned electric utilities available from Edison Electric Institute [19]. All costs are adjusted for inflation to real 2015 dollars using the Consumer Price Index [20]. Figures 10–12 show the distribution capital costs normalized per utility customer, kW of peak demand, and kWh of energy sold, respectively.

TABLE 5

We perform separate linear regressions analyzing the relationship between the outcome variable annual distribution capital spending (in real 2015 dollars) and three predictor variables. The results of the regressions for each predictor considered are given.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	$189/Customer-Year	$1.44/Customer-Year	$< 2 \times 10^{-16}$	0.856
Annual Peak Demand	$34/kW-Year	$0.4/kW-Year	$< 2 \times 10^{-16}$	0.741
Annual Energy Sales	0.74 ¢/kWh	0.009 ¢/kWh	$< 2 \times 10^{-16}$	0.705

FIGURE 10

The average cost of distribution capital infrastructure has been approximately $150–$200/Customer-Year since 1975, and has not increased significantly in recent years. Prior to 1975, distribution capital costs per customer were higher, peaking above $300/Customer-Year in 1973.

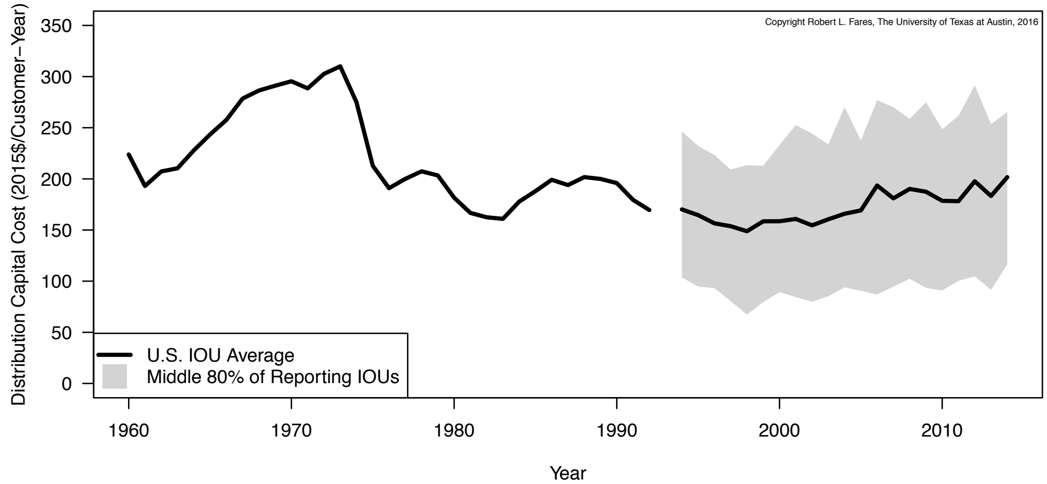


FIGURE 11

Average distribution capital costs per kW of annual peak demand decreased significantly between the years 1960–1980, falling from over $100/kW-Year to less than $40/kW-Year. Since 1980, average distribution capital costs have been approximately $30–$40/kW-Year.

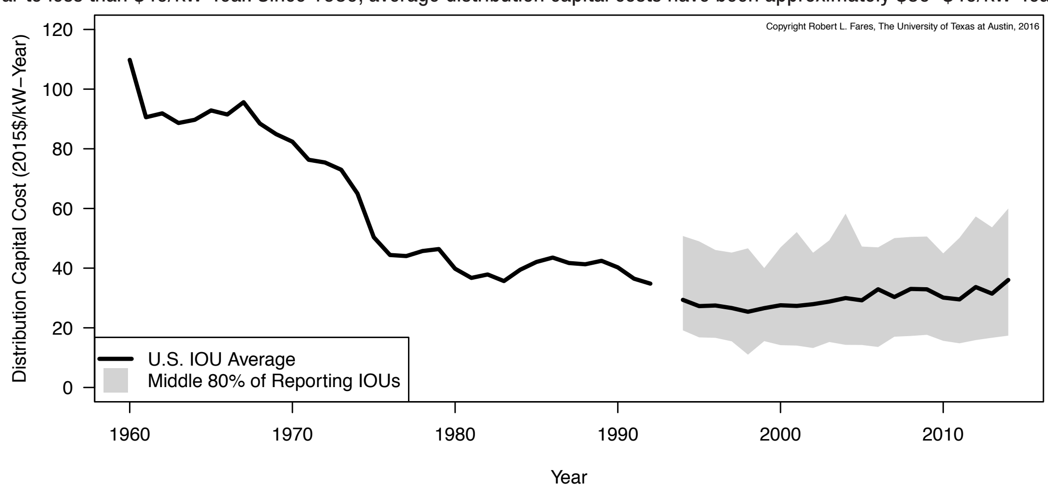
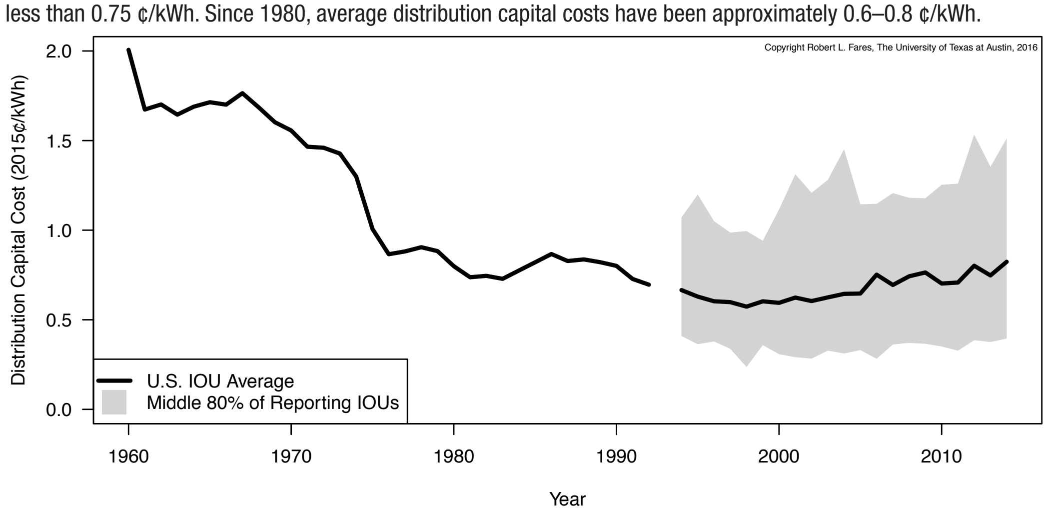


FIGURE 12

Average distribution capital costs per kWh of energy sold decreased significantly between the years 1960–1980, falling from approximately 2 ¢/kWh to less than 0.75 ¢/kWh. Since 1980, average distribution capital costs have been approximately 0.6–0.8 ¢/kWh.



Distribution capital costs per customer were approximately $200/Customer-Year (similar to 2014) in 1960, and then increased from 1960–1973, ultimately peaking above $300/Customer-Year. After 1973, distribution capital costs declined to today's average cost of $150–$200/Customer-Year. Distribution capital costs per kW of annual peak demand and per kWh of energy sold exhibit different behavior, declining from 1960 until 1980, and ultimately converging to the present costs of $30–$40/kW-Year or 0.6–0.8 ¢/kWh. The difference between the trend in capital cost per customer versus the trend in capital cost per kW-Year or kWh is likely caused by the fact that utility customers used significantly less energy before 1980 than they did subsequent to 1980. As shown in the previous section, the number of customers in a utility's territory is the best predictor for annual distribution system capital costs.

4.3 Relationship Between Distribution System Operation and Maintenance Costs and Utility Customers, Demand, and Energy Sales

Distribution system operation and maintenance costs include operation supervision and engineering costs, load dispatching costs, substation expenses, electrical energy losses costs, distribution equipment maintenance costs, and a number of other recurring costs associated with the operation and maintenance of the electricity distribution system. A complete breakdown of these costs is available on Page 322 of FERC Form 1 [12]. Once again, we adjust all costs for inflation to real 2015 dollars using the Consumer Price Index released by the U.S. Bureau of Labor Statistics, and perform separate linear regressions on the number of utility customers, MW demand, and MWh sales. Table 6 presents the results of the regression analyses. Each regression considers 2910 individual utility reports between the years 1994–2014, or an average of 139 utility reports per year. Figure A13–A15 in Appendix A.3.2 show the raw data and the corresponding regression lines. The results are similar to the results for annual spending on new distribution system capital infrastructure. The number of utility customers is found to be the best predictor for annual costs.

4.4 Variation in Distribution System Operation and Maintenance Costs Over Time

Data from the FERC Form 1 database is used to show average distribution system operation and maintenance costs and variation in costs between utilities for the years 1994–2014. No data is available for distribution system operation and maintenance costs prior to 1994 because the Edison Electric Institute only reports total annual operation and maintenance costs for transmission and distribution [19]. Figures 13–15 show distribution operation and maintenance costs during the years 1994–2014 normalized per utility customer, per kW of peak demand, and per kWh of energy sold, respectively. All costs are adjusted for inflation to real 2015 dollars.

TABLE 6

We perform separate linear regressions analyzing the relationship between annual distribution system operation and maintenance costs (in real 2015 dollars) and three predictor variables. The results of the regressions for each predictor considered are given.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	$102/Customer-Year	$0.7/Customer-Year	$< 2 \times 10^{-16}$	0.891
Annual Peak Demand	$18/kW-Year	$0.2/kW-Year	$< 2 \times 10^{-16}$	0.757
Annual Energy Sales	0.40 ¢/kWh	0.005 ¢/kWh	$< 2 \times 10^{-16}$	0.729

FIGURE 13

Distribution system operation and maintenance costs have been approximately $100/Customer-Year on average since 1994.

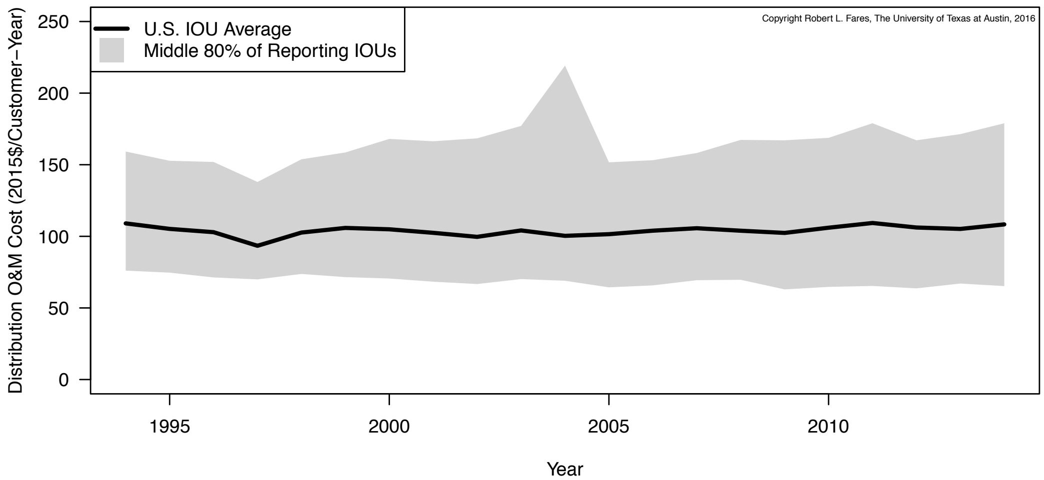


FIGURE 14

Distribution system operation and maintenance costs have been approximately $18/kW-Year on average since 1994, but some utilities had costs much higher than average.

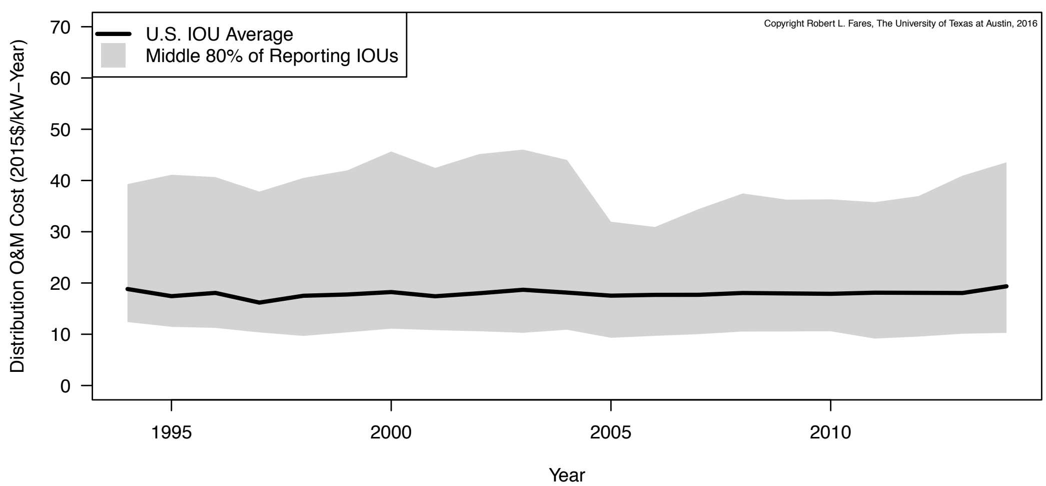
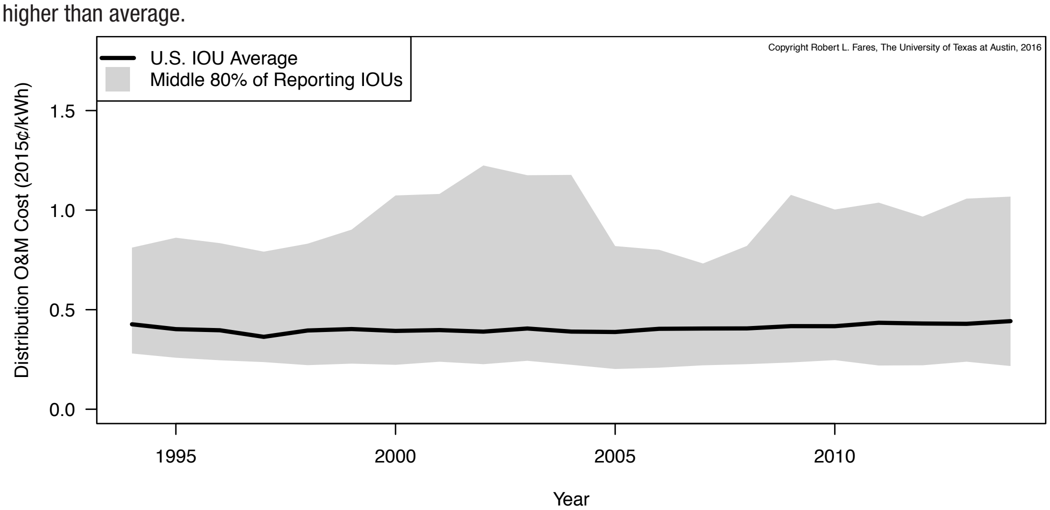


FIGURE 15

Distribution system operation and maintenance costs have been approximately 0.4 ¢/kWh on average since 1994, but some utilities had costs much higher than average.



Average distribution system operation and maintenance costs were roughly constant between the years 1994 and 2015, approximately equal to \$100/Customer-Year, \$18/kW-Year, or 0.4 ¢/kWh. As shown in the previous section, the number of customers in a utility's territory is the best predictor for distribution system operation and maintenance costs, leading to lower variability in the cost per customer than in the cost per kW-Year or kWh.

4.5 Relationship Between Total Distribution System Costs and Utility Customers, Demand, and Energy Sales

To show the total (capital, operation, and maintenance) costs associated with electricity distribution, we repeat the regression analyses for the total distribution cost versus the number of utility customers, annual peak power demand, and annual energy sales. The results of these analyses are given in Table 7. The raw annual distribution capital plus operation and maintenance cost data and corresponding regression lines are illustrated in Figures A16–A18 in Appendix A.3.3. The number of customers in a utility's territory is the most accurate predictor for annual electricity distribution costs.

Put together, our findings on the average cost of electricity distribution for investor owned utilities in the United States show that the average cost for electricity distribution system capital infrastructure, operation, maintenance is approximately \$291 per customer per year, \$53 per kW of peak demand per year, or 1.1 ¢ per kWh of energy sold, with all costs measured in real 2015 dollars. While distribution costs are typically recovered by a combination of customer charges, kW charges, and kWh charges, our findings indicate that the number of customers in a utility's territory is the best predictor for annual electricity distribution costs. Thus, it might make sense to recover distribution-related costs using a monthly fixed charge per customer rather than per kW or per kWh charges.

4.6 Variation in Total Distribution System Costs Over Time

We use data from the FERC Form 1 database to show the average cost for U.S. investor-owned utilities and the variation in costs between utilities for the years 1994–2014. We also use data provided by the Edison Electric Institute to show the variation in the average capital cost for new distribution infrastructure for the years 1960—1992 [19]. These data do not provide annual operation and maintenance costs for distribution only, but rather report total operation and maintenance costs for transmission and distribution. We adjust all costs for inflation to real 2015 dollars using the Consumer Price Index [20]. Figures 16–18 show annual distribution costs normalized by the number of customers in a utility's territory, annual peak kW demand, and annual kWh energy sales, respectively.

TABLE 7

We perform separate linear regressions analyzing the relationship between total annual distribution capital, operation, and maintenance costs (in real 2015 dollars) and three predictor variables. The number of customers in a utility's territory is found to be the best predictor for total distribution system costs.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	\$291/Customer-Year	\$1.8/Customer-Year	$< 2 \times 10^{-16}$	0.901
Annual Peak Demand	\$52/kW-Year	\$0.5/kW-Year	$< 2 \times 10^{-16}$	0.775
Annual Energy Sales	1.1 ¢/kWh	0.013 ¢/kWh	$< 2 \times 10^{-16}$	0.740

FIGURE 16

The average cost of distribution system capital infrastructure, operation, and maintenance (in real 2015 dollars) was $250–$300/Customer-Year from 1994–2014. The average annual cost for new distribution capital infrastructure during the years 1960–1992 is shown for reference.

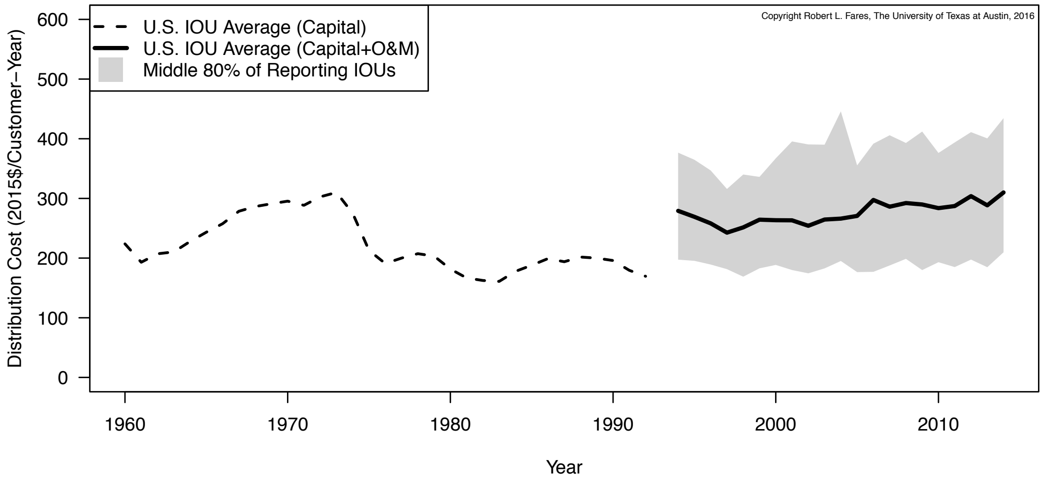
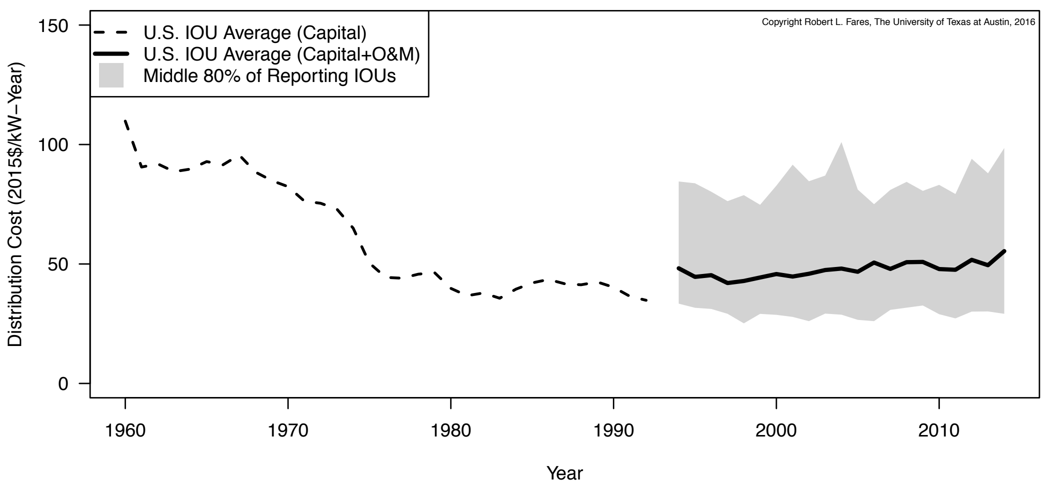


FIGURE 17

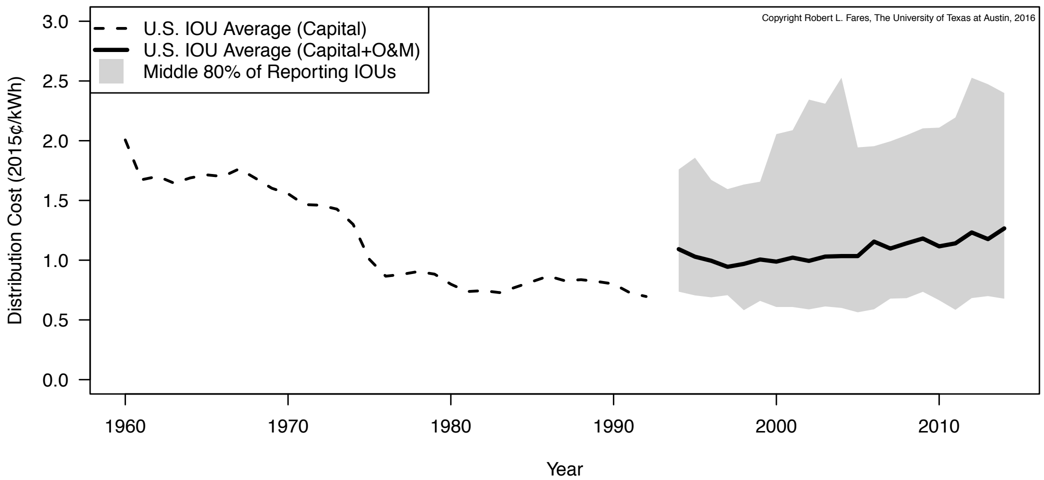
The average cost of distribution system capital infrastructure, operation, and maintenance (in real 2015 dollars) was approximately $40–$50/kW-Year from 1994–2014. The average annual cost for new distribution capital infrastructure during the years 1960–1992 is shown for reference.



Electricity distribution capital, operation, and maintenance costs have been roughly constant since 1994. Because the number of customers in a utility's territory is the best overall predictor for annual distribution costs, there is less variation in costs between utilities when costs are measured on a $/Customer-Year basis than when costs are measured on a $/kW-Year or ¢/kWh basis. The gray area shown in Figure 16 is relatively small in area and roughly centered around the average cost, while the gray area illustrated in Figure 18 is larger and not centered around the mean. ■

FIGURE 18

The average cost of distribution system capital infrastructure, operation, and maintenance (in real 2015 dollars) was approximately 0.9–1.1 ¢/kWh from 1994–2014. The average annual cost for new distribution capital infrastructure during the years 1960–1992 is shown for reference.



5 | UTILITY ADMINISTRATION COSTS

In addition to the costs for electricity transmission and distribution, there are also costs associated with the utility business of monitoring and controlling the grid system, managing customer accounts, etc. While these costs are not directly associated with the production or delivery of electric energy, they are a necessary component of providing electricity service to customers. As was done for electricity transmission and distribution, we analyze administrative capital costs separately from administrative operation and maintenance costs. For each of these costs, we analyze a total of 2010 individual utility reports between 1994–2014, or an average of 96 reporting utilities per year. All cost data is adjusted for inflation according to the Consumer Price Index [20].

5.1 Relationship Between Utility Administration Capital Costs and Utility Customers, Demand, and Energy Sales

Table 8 reports results from separate regression analyses for annual spending on new administrative capital infrastructure (e.g. land, buildings, tools, communication equipment, office furniture, software, etc.) versus the number of utility customers, annual peak demand, and annual energy sales. Figures A19–A21 in Appendix A.4.1 show the raw data and the corresponding regression lines for each one of the regression analyses.

None of the predictors considered can accurately predict administrative capital costs. This finding is not surprising because these costs do not fundamentally scale with the number of customers in a utility's territory or customers' demand for electricity. While none of the predictors accurately predict cost outcomes, the value of the coefficients can be used to understand how administrative capital costs might be allocated.

5.2 Variation in Utility Administration Capital Costs Over Time

We use data from the FERC Form 1 database to show the average cost for U.S. investor-owned utilities and the variation in costs between utilities for the years 1994–2014. We also use data provided by the Edison Electric Institute to show the variation in the average capital cost for new administrative infrastructure and equipment for the years 1960–1992 [19]. We adjust all costs for inflation to real 2015 dollars using the Consumer Price Index [20]. Figures 19–21 show annual administrative capital costs normalized by the number of customers in a utility's territory, annual peak kW demand, and annual kWh energy sales, respectively.

The data show that administrative capital costs were higher prior to 1992 than during the years 1994–2014. However, this difference might be caused by the fact that we used different datasets

TABLE 8

We perform separate linear regression analyses on the outcome variable annual administrative capital costs (in real 2015 dollars) versus three predictor variables. None of the predictors closely predict administrative capital costs, but the value of the coefficients can be used to understand how administrative costs might be allocated.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	$40/Customer-Year	$1.1/Customer-Year	$<2 \times 10^{-16}$	0.382
Annual Peak Demand	$7.9/kW-Year	$0.2/kW-Year	$<2 \times 10^{-16}$	0.395
Annual Energy Sales	0.17 ¢/kWh	0.005 ¢/kWh	$<2 \times 10^{-16}$	0.379

to show costs during years 1960–1992 and years 1994–2014. During both periods of time, administrative capital costs were roughly constant and comprised a relatively small portion of overall electricity costs.

FIGURE 19

Average administrative capital costs have been approximately $15–$35/Customer-Year since 1994.

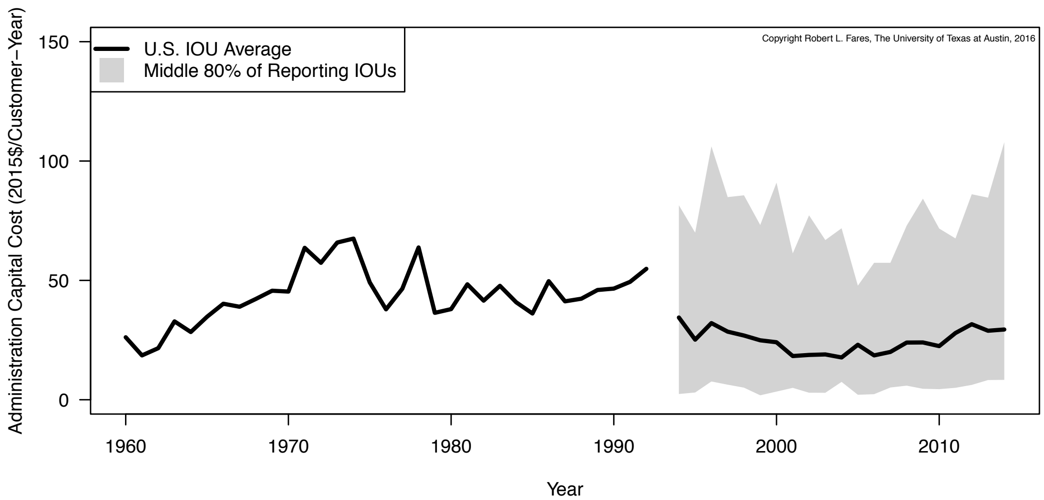


FIGURE 20

Average administrative capital costs have been approximately $3–$6/kW-Year since 1994.

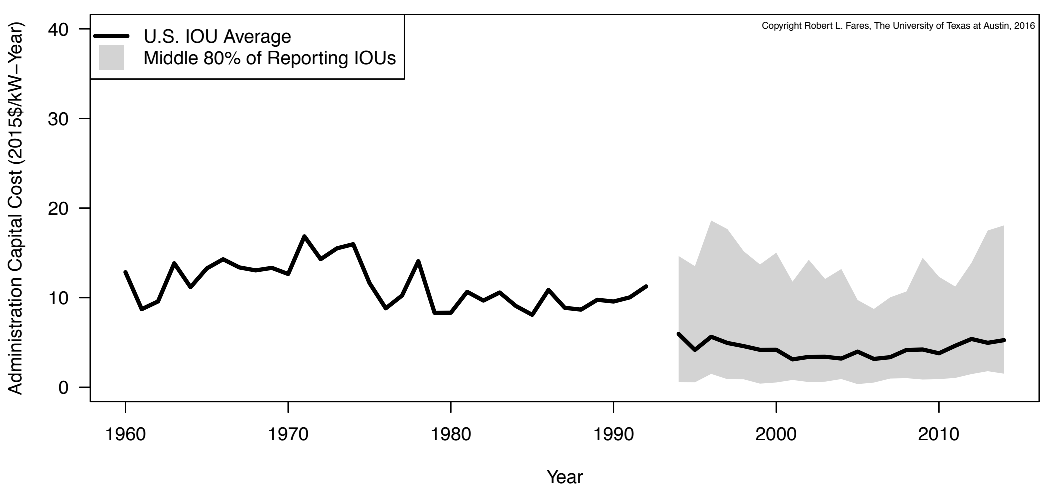
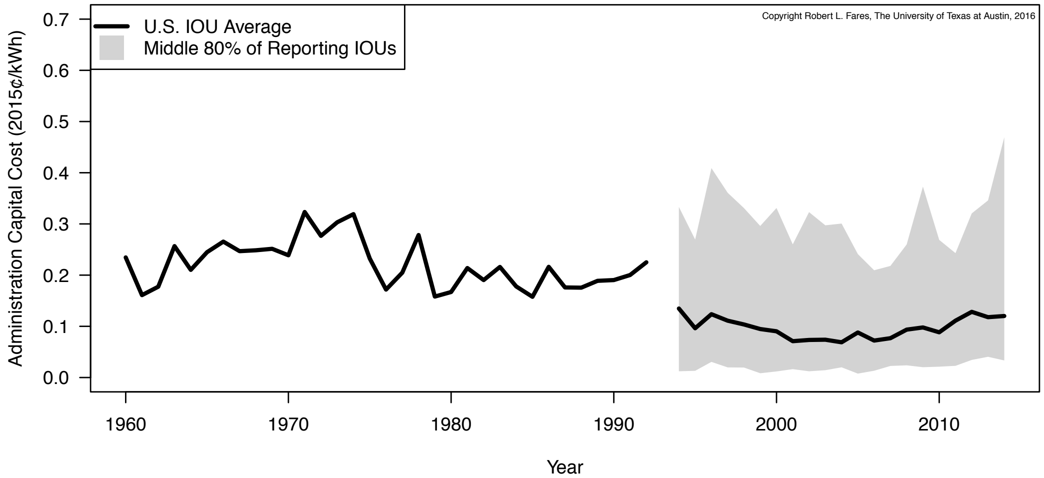


FIGURE 21

Average administrative capital costs have been approximately 0.06–0.14 ¢/kWh since 1994.



5.3 Relationship Between Utility Administration Operation and Maintenance Costs and Utility Customers, Demand, and Energy Sales

Annual administrative operation and maintenance costs include expenses associated with customer account management, energy sales, customer service and information services, and other recurring administrative and general expenses. Table 9 provides the value of the coefficients and statistics for each regression analysis. Figures A23–A24 in Appendix A.4.2 show the raw data and corresponding regression lines.

The number of customers in a utility's territory is the best predictor for annual administrative operation and maintenance costs. This result makes sense from a fundamental perspective because administrative costs associated with customer accounts and customer service are related to the number of utility customers. Note that annual administrative operation and maintenance costs are nearly an order of magnitude higher than administrative capital costs.

5.4 Variation in Utility Administration Operation and Maintenance Costs Over Time

As was done for utility administration capital costs, we examine the variation in utility administrative operation and maintenance costs over time. We use data from the FERC Form 1 database to show the average cost for U.S. investor-owned utilities in the variation in costs between utilities for the years 1994–2014. We also use data provided by the Edison Electric Institute to show the average cost for investor-owned utilities during the years 1960–1992 [19]. All costs are adjusted for inflation to real 2015 dollars using the Consumer Price Index [20]. Figures 22–24 show annual administrative operation and maintenance costs normalized per utility customer, per kW of annual peak demand, and per kWh of annual energy sales, respectively.

TABLE 9

We perform separate linear regression analyses on the outcome variable annual administrative operation and maintenance costs (in real 2015 dollars) versus three predictor variables. The number of customers in a utility's territory is the best predictor for annual costs.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	\$293/Customer-Year	\$2.7/Customer-Year	$<2 \times 10^{-16}$	0.857
Annual Peak Demand	\$53/kW-Year	\$0.7/kW-Year	$<2 \times 10^{-16}$	0.754
Annual Energy Sales	1.2 ¢/kWh	0.016 ¢/kWh	$<2 \times 10^{-16}$	0.722

FIGURE 22

Average administrative operation and maintenance costs per customer increased gradually between 1960 and the mid 1980s, but have declined or been roughly constant since 1994. Between 1960 and 2014, average administrative operation and maintenance costs varied from approximately $190–$370/Customer-Year.

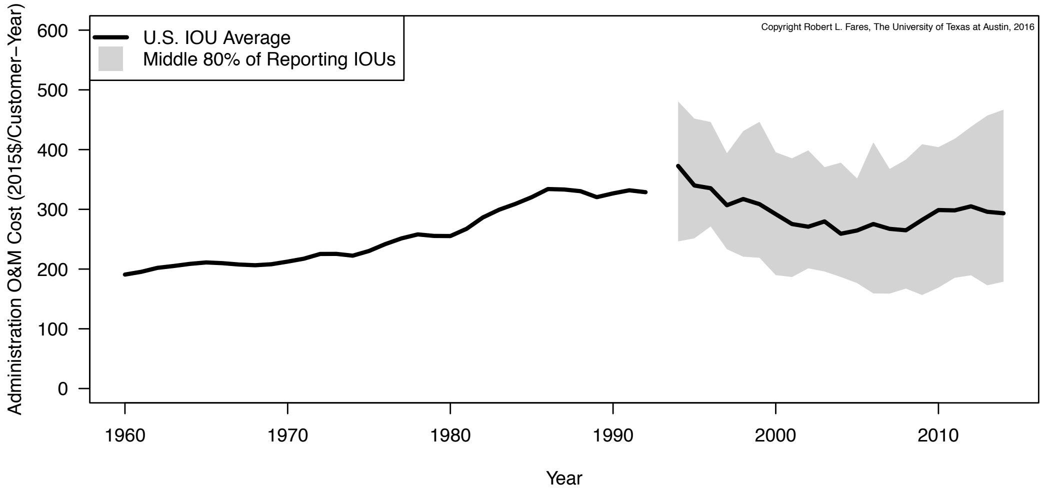


FIGURE 23

Average administrative operation and maintenance costs per kW of annual peak demand declined between 1960 and 1975 as the average demand per customer increased. Since 1975, administrative operation and maintenance costs have been $45–$75/kW-Year.

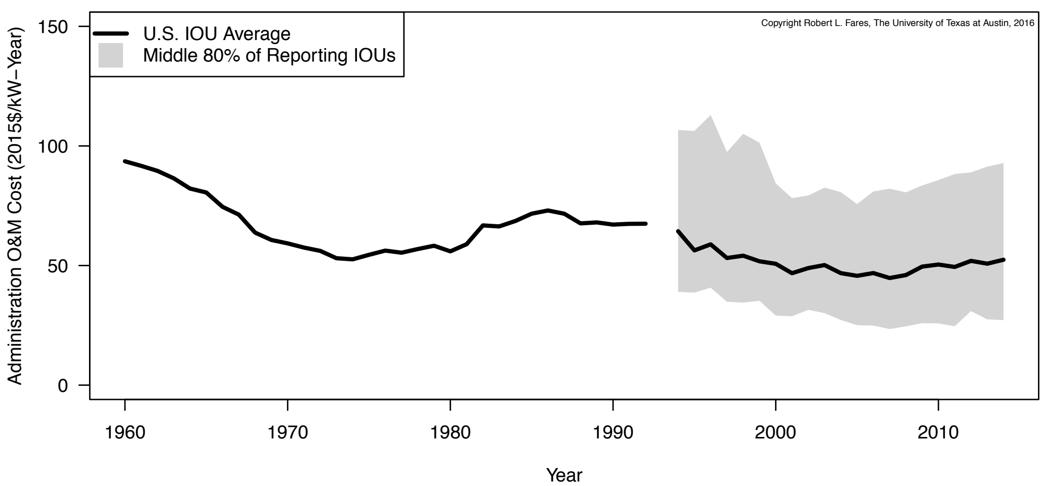


FIGURE 24

Average administrative operation and maintenance costs per kWh of energy consumption declined after 1960 as the average energy consumption per customer increased. Since 1975, average administrative operation and maintenance costs have been 1.0–1.4 ¢/kWh.

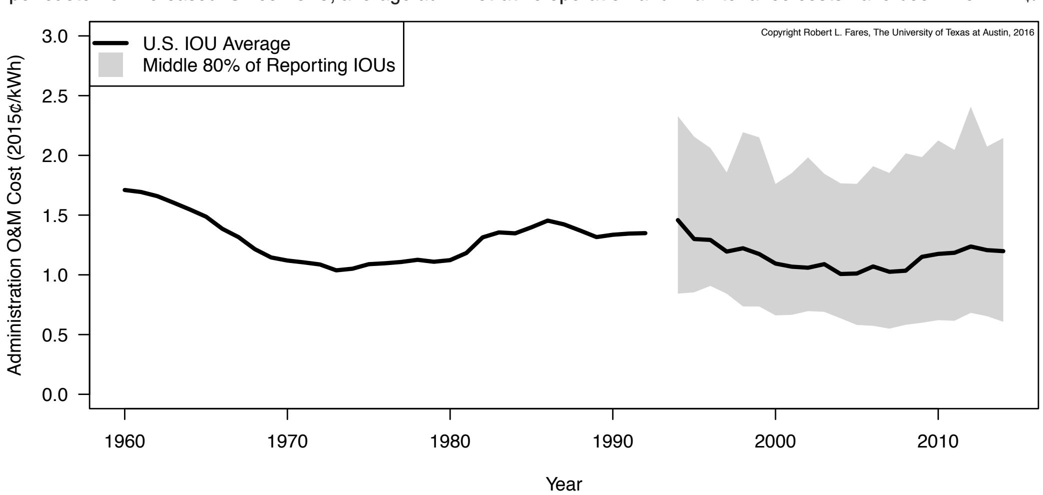


TABLE 10

We perform separate linear regression analyses on total annual administrative capital, operation, and maintenance costs (in real 2015 dollars) versus three predictor variables. The number of customers in a utility's territory is the best predictor for total annual costs.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	$333/Customer-Year	$3.1/Customer-Year	$<2 \times 10^{-16}$	0.853
Annual Peak Demand	$61/kW-Year	$0.8/kW-Year	$<2 \times 10^{-16}$	0.766
Annual Energy Sales	1.3 ¢/kWh	0.018 ¢/kWh	$<2 \times 10^{-16}$	0.734

5.5 Relationship Between Total Utility Administration Costs and Utility Customers, Demand, and Energy Sales

When annual spending on new administrative capital infrastructure and administrative operation and maintenance are considered together, the number of customers in a utility's territory emerges as the best overall predictor for total annual administrative costs. Table 10 provides the results of the regression analyses of total annual administrative costs versus the three predictors considered. Figures A25–A27 in Appendix A.4.3 show the raw data and corresponding regression lines.

The number of customers in a utility's territory emerges as the single best predictor for annual administrative costs. Thus, it might be useful for the utility to recover these costs using a fixed monthly customer charge rather than volumetric charges per unit of energy or power consumption.

5.6 Variation in Total Utility Administration Costs Over Time

As was done for the other costs considered in this paper, we analyze the variation in total utility administration capital, operation, and maintenance costs over time. We use data from the FERC Form 1 database to show the average cost for U.S. investor-owned utilities and the variation in costs between individual utilities for the years 1994–2014. We also use data provided by the Edison Electric Institute to show the variation in average administration costs between the years 1960–1992 [19]. All costs are adjusted for inflation to real 2015 dollars using the Consumer Price Index [20]. Figures 25–27 show the variation in total administrative costs between the years 1960–2014 normalized per utility customer, per kW of peak demand, and per kWh of energy sold, respectively.

FIGURE 25

Average administrative capital, operation, and maintenance costs per customer increased gradually between 1960 and 1970, but have declined or been roughly constant since 1994. Between 1960 and 2014, average administrative operation and maintenance costs varied from approximately $200–$400/Customer-Year.

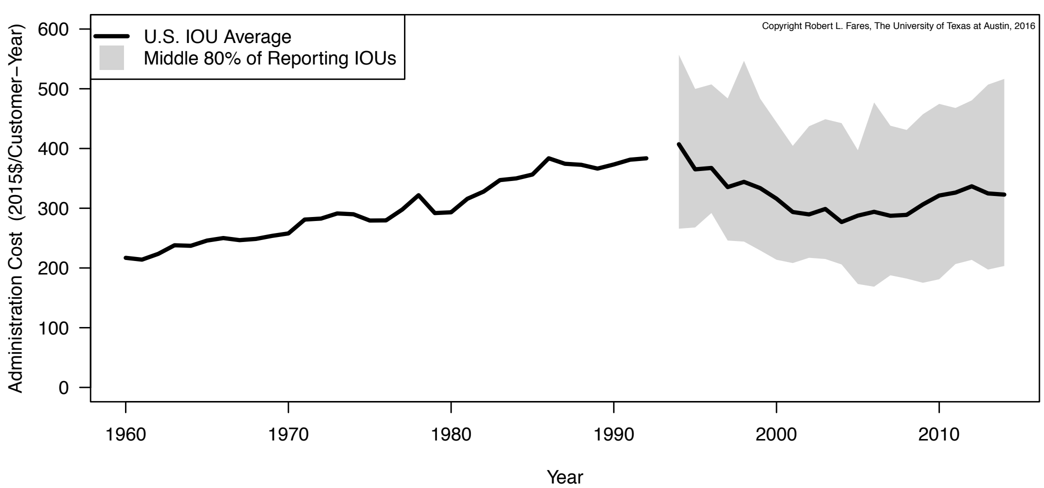


FIGURE 26

Average administrative capital, operation, and maintenance costs per kW of annual peak demand declined between 1960 and 1970 as the average demand per customer increased. Since 1970, administrative operation and maintenance costs have been approximately $50–$80/kW-Year.

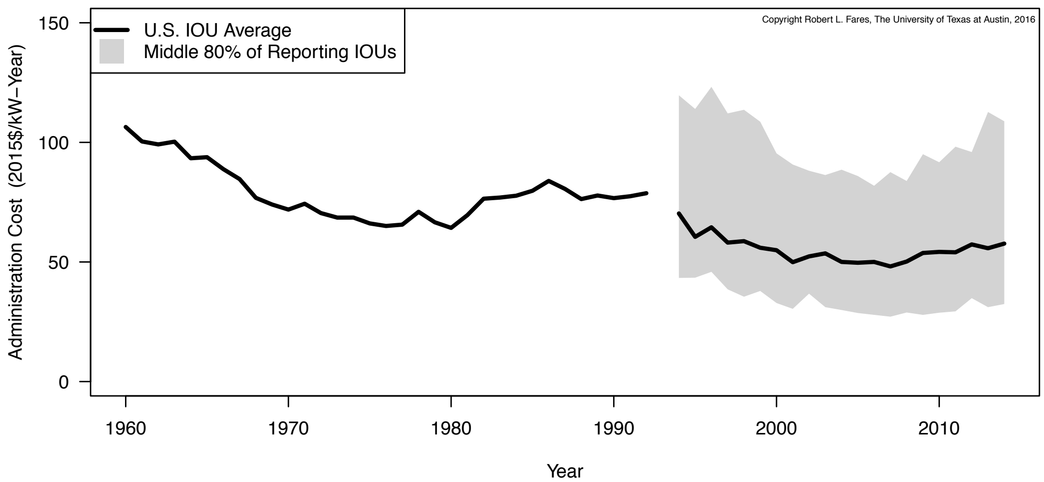
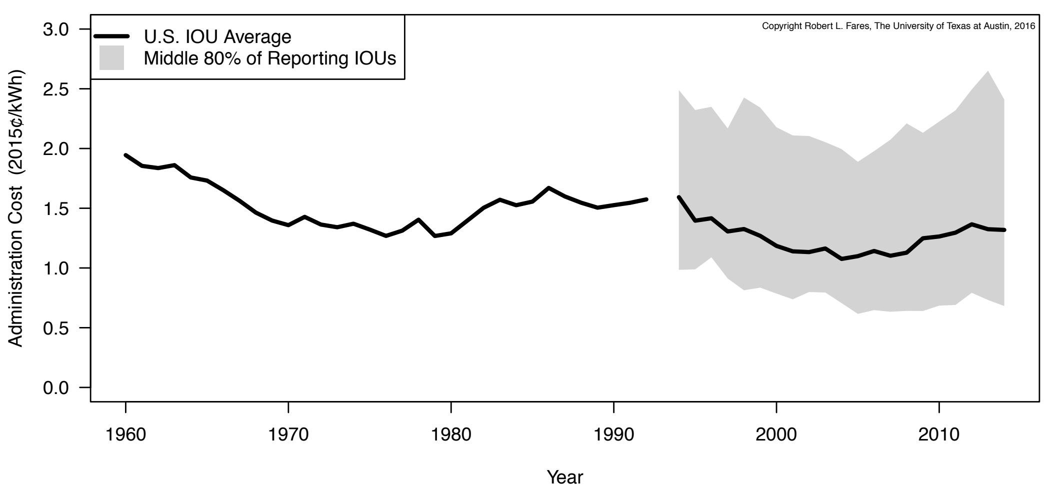


FIGURE 27

Average administrative capital, operation, and maintenance costs per kWh of energy consumption declined after 1960 as the average energy consumption per customer increased. Since 1970, average administrative operation and maintenance costs have been 1.1–1.6 ¢/kWh.



6 | SUMMARY OF TRANSMISSION, DISTRIBUTION, AND ADMINISTRATION COSTS

If we examine the variation of total transmission, distribution, and administrative (TD&A) capital, operation, and maintenance costs versus the number of utility customers, annual peak demand, and annual energy sales, we find that the number of customers in a utility's territory is the best predictor for total annual TD&A costs, as shown by the regression results given in Table 11. Figures 28–30 show the raw data and the corresponding regression lines.

Table 12 summarizes the results of the regression analyses on transmission costs, distribution costs, administration costs, and total TD&A costs. For all of the costs considered, the number of customers in a utility's territory is the single best

TABLE 11

We perform separate regressions on total transmission, distribution, and administrative (TD&A) capital, operation, and maintenance costs (in real 2015 dollars). The number of customers in a utility's territory is the best predictor for annual TD&A costs.

Predictor Variable	Coefficient	Standard Error	p Value	R^2
Total Customers	\$727/Customer-Year	\$6.1/Customer-Year	$<2 \times 10^{-16}$	0.886
Annual Peak Demand	\$133/kW-Year	\$1.6/kW-Year	$<2 \times 10^{-16}$	0.781
Annual Energy Sales	2.9 ¢/kWh	0.039 ¢/kWh	$<2 \times 10^{-16}$	0.747

FIGURE 28

The number of customers in a utility's territory is the single best predictor for total annual transmission, distribution, and administration costs. The average cost from 1994–2014 was \$727/Customer-Year with all costs measured in 2015 dollars.

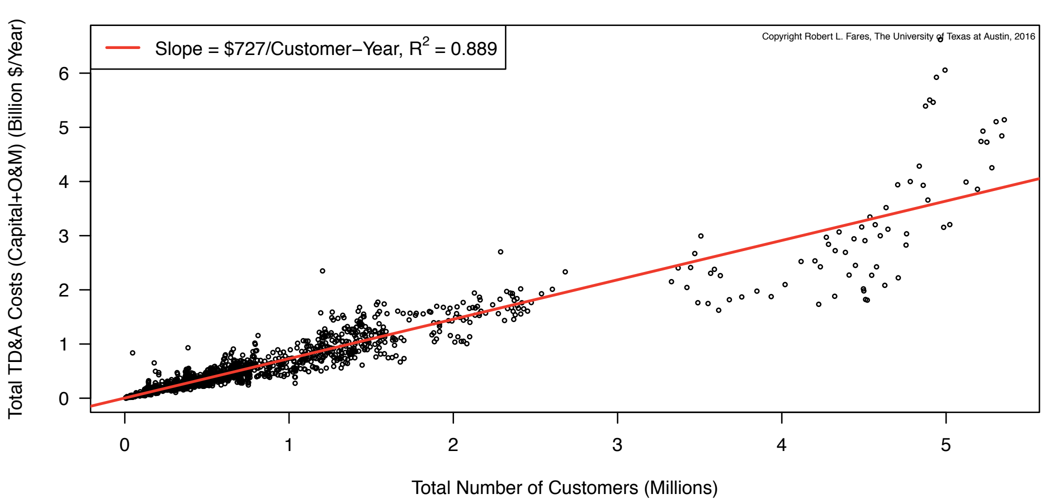


FIGURE 29

A utility's annual peak demand is a less accurate predictor for total annual transmission, distribution, and administration costs than the number of customers in its territory. The average cost from 1994–2014 was $133/kW-Year with all costs measured in 2015 dollars.

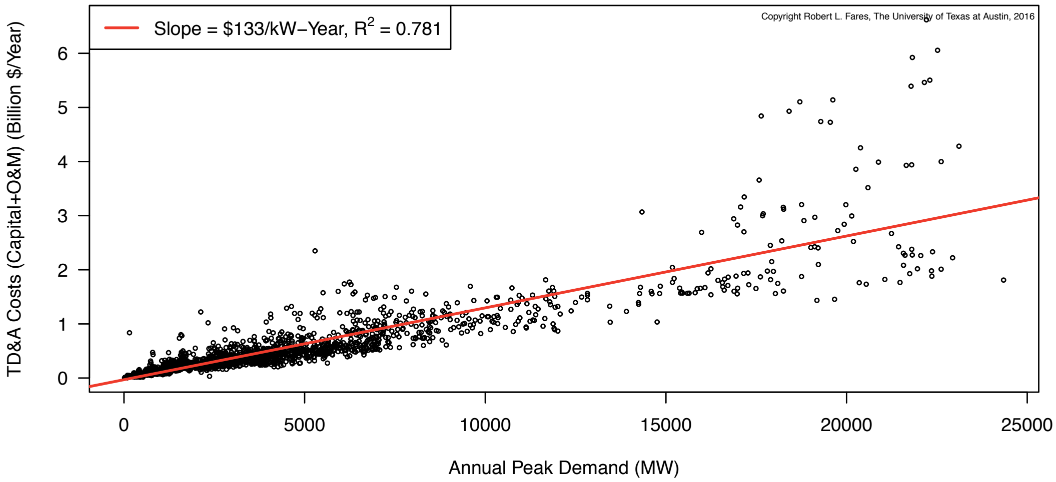


FIGURE 30

A utility's annual volume of energy sales is a less accurate predictor for total annual transmission, distribution, and administration costs than the number of customers in its territory. The average cost from 1994–2014 was 2.8 ¢/kWh with all costs measured in 2015 dollars.

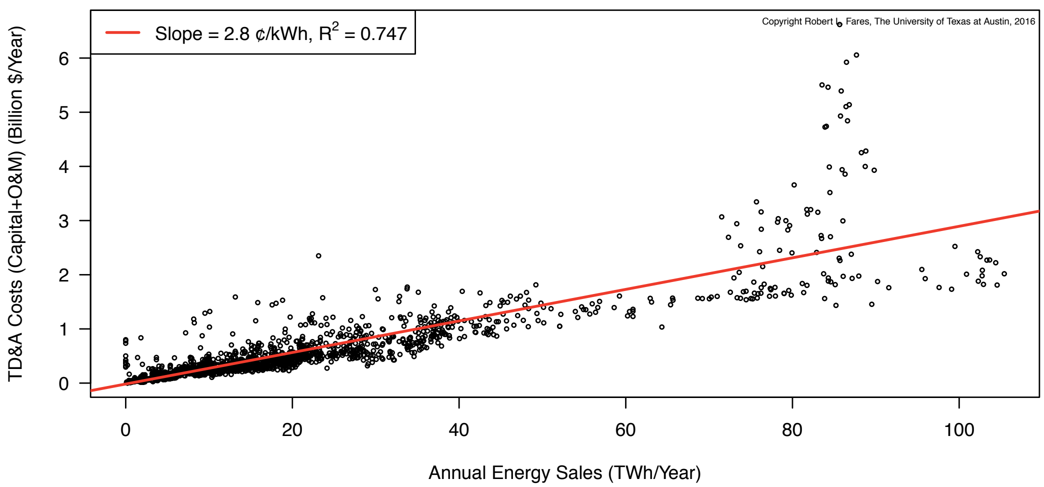


TABLE 12

This table summarizes the correlation between total annual transmission, distribution, and administration costs and the number of customers in a utility's territory, annual peak demand, and annual energy sales. The value of the cost coefficient and the corresponding R2 value are given for each regression analysis performed in this paper. The number of customers in a utility's territory emerges as the single best predictor for annual TD&A costs.

Cost Category	Cost Per Customer (2015$/Customer-Year)	Cost Per Peak KW (2015$/kW-Year)	Cost Per kWh (2015¢/kWh)
Transmission	119 (R^2 = 0.459)	21 (R^2 = 0.399)	0.47 (R^2 = 0.373)
Distribution	291 (R^2 = 0.901)	52 (R^2 = 0.775)	1.1 (R^2 = 0.740)
Administration	333 (R^2 = 0.853)	61 (R^2 = 0.766)	1.3 (R^2 = 0.734)
Total	727 (R^2 = 0.886)	134 (R^2 = 0.781)	2.9 (R^2 = 0.747)

predictor for annual costs. Notably, administration costs comprise a larger share of overall TD&A costs than either transmission or distribution.

We also show the variation in total average transmission, distribution, and administration capital, operation, and maintenance costs over time. Data from FERC Form 1 is used to show the average cost for U.S. investor-owned utilities for the years 1994–2014, and data from the Edison Electric Institute is used to show the average cost for the years 1960–1992. Figures 31–33 show the variation in average TD&A costs over time separated by spending category normalized per customer, per kW of peak demand, and per kWh of energy sold, respectively.

When measured on a $/Customer-Year basis, the average cost for transmission, distribution, and administration has been roughly $700-$800/Customer-Year for much of the past 54 years, with the exception of the late 1960s and early 1970s, when a major build out of transmission and distribution infrastructure occurred, and the

FIGURE 31

Average annual TD&A costs have been roughly $700–$800/Customer-Year for much of the past 54 years, with the exception of the late 1960s and early 1970s, when a major build out of transmission and distribution infrastructure occurred, and the 2010s, which have seen increasing TD&A costs driven mostly by transmission investments.

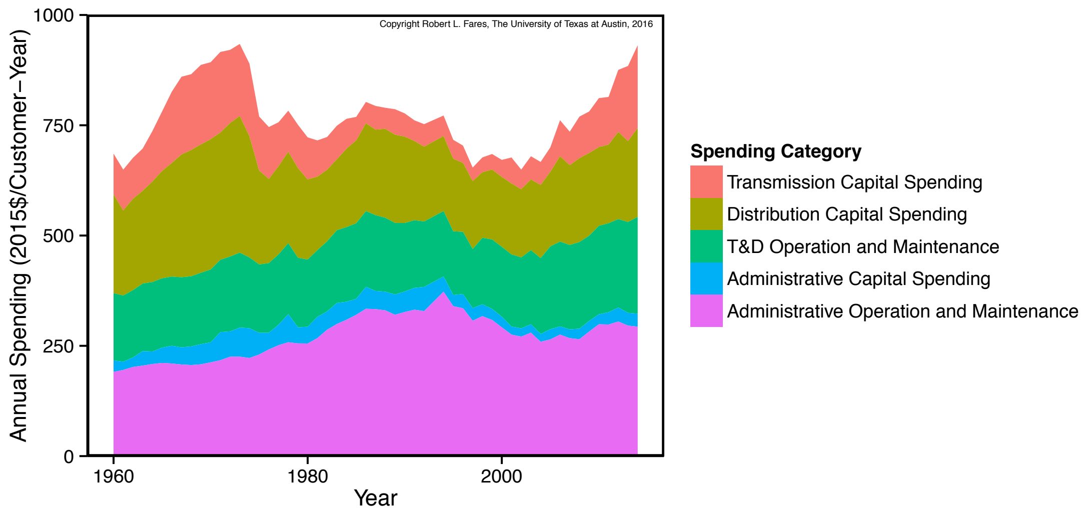


FIGURE 32

Average annual TD&A costs per kW-Year declined between 1960 and 1980, but have been approximately $110–$170/kW-Year since 1980. The decrease between 1960 and 1980 was likely driven by increasing energy demand rather than decreasing service costs.

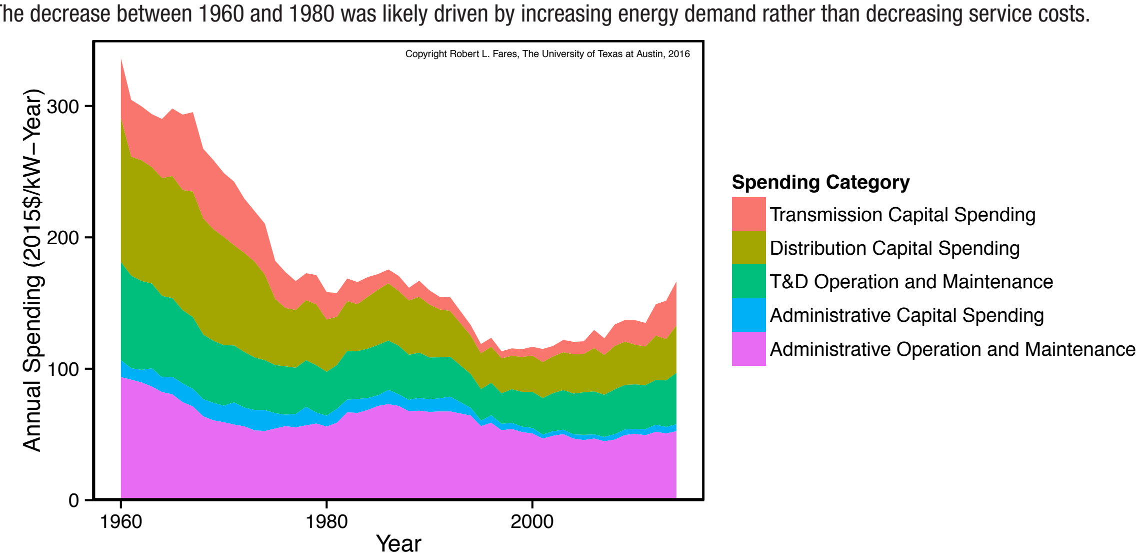
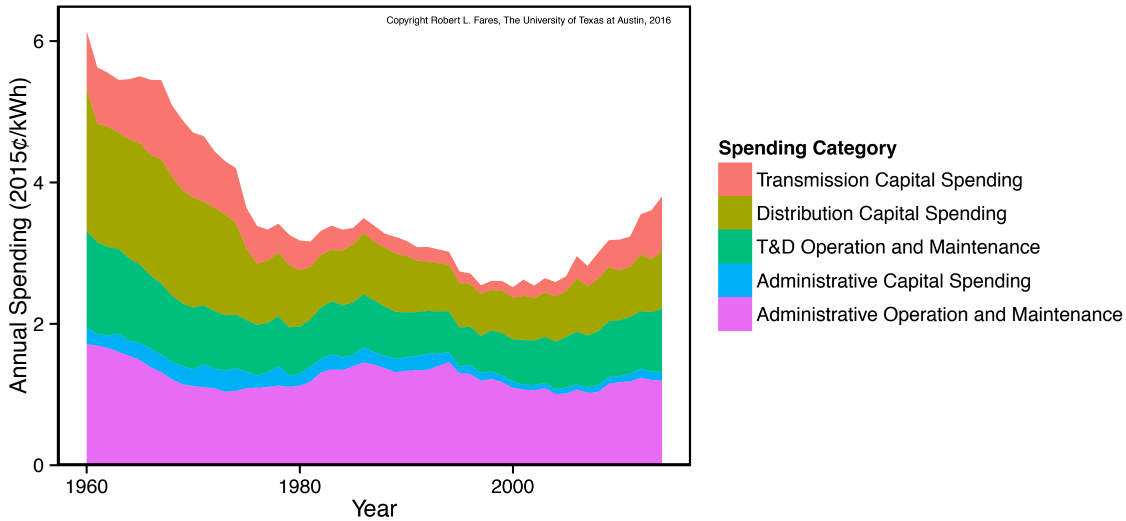


FIGURE 33

Average annual TD&A costs per kWh declined between 1960 and 1980, but have been approximately 2.5–3.5 ¢/kWh since 1980. The decrease between 1960 and 1980 was likely driven by increasing energy consumption rather than decreasing service costs.



2010s, which have seen TD&A costs above $800/Customer-Year driven mostly by transmission investments.

When measured on a $/kW-Year or ¢/kWh basis, the average cost for transmission, distribution, and administration declined from 1960–1980 and varied only slightly from 1980–2014. The decreasing trend in cost per unit of demand or energy sold from 1960–1980 is likely caused by the fact that the average energy consumption per customer nearly doubled from 11,700 kWh/Customer-Year in 1960 to 24,400 kWh/Customer-Year in 1980. However, the average energy consumption per customer remained roughly flat between 1980 and 2014, ranging from 23,300 kWh/Customer-Year to 26,900 kWh/Customer-Year.

Note that this figure is an average across residential, commercial, and industrial customers. Residential, commercial, and industrial energy consumption per customer all saw similar dramatic increases after 1960. Figures A28–A31 in Appendix A.5 show the variation in energy consumption per customer over time by customer class. Because the number of customers in a utility's territory was found to be the best predictor for annual TD&A costs, it is very likely that the decline in TD&A costs per kW-Year and per kWh shown in Figures 32–33 was caused by increasing energy consumption per customer, and not a real decline in the cost of utility service. This finding is further evidence that the primary driver of utility TD&A costs is the number of utility customers, and not the level of annual peak power demand or annual energy sales. ■

7 | DISCUSSION AND CONCLUSIONS

This paper analyzed the cost of electricity transmission, distribution, and administration (TD&A) in the United States using data catalogued by FERC and the Edison Electric Institute. Because utility costs are recovered using a combination of monthly $/Customer charges, $/kW charges, and $/kWh charges, we analyzed the influence of a utility's customer count, annual peak demand, and annual energy sales on its annual TD&A capital, operation, and maintenance costs.

We found that the number of customers in a utility's territory is the single best predictor for annual TD&A costs. The average total TD&A cost per customer during the years 1994–2014 was found to be approximately $727/Customer-Year in real 2015 dollars. When the variation in average TD&A costs is examined between the years 1960 and 2014, it is found that TD&A costs have been roughly constant and equal to $700–$800/Customer-Year for much of the past 54 years, with the exception of the late 1960s and early 1970s when a significant build out of new transmission and distribution infrastructure occurred.

An emerging issue related to the allocation of TD&A costs is the growing use of distributed electricity generation in the form of rooftop solar photovoltaic panels. Often, production from photovoltaic panels is credited according to a ``net-metering" tariff, where customers pay for their net energy consumption minus solar generation in kWh at the prevailing ¢/kWh rate established by the utility. This method of payment for customer-produced electric energy can be problematic because it effectively reduces a utility's volumetric energy sales without reducing the number of customers that need TD&A services. Thus, if costs are recovered using a conventional volumetric energy charge, the utility must increase its ¢/kWh electricity rate to compensate for decreasing energy sales. The historical trend in TD&A costs per kWh shown in Figure 33 illustrates how average TD&A costs per kWh might increase as the volume of kWh energy sales decreases. In 1960, the average energy consumption per customer was 11,700 kWh/Customer-Year, less than half the value in 2014 of 25,200 kWh/Customer-Year. Note these figures are averages across residential, commercial, and industrial customers. Residential, commercial, and industrial energy consumption per customer all saw similar dramatic increases after 1960, as shown in Figures A28–A31 in Appendix A.5. The lower energy consumption in 1960 caused the TD&A cost per kWh to be approximately 6 ¢/kWh, nearly double the 2014 TD&A cost of approximately 3 ¢/kWh. Thus, if volumetric energy sales decrease over the coming years due to wider use of distributed generation, one would expect TD&A costs per kWh to approach the higher costs seen in the 1960s, when energy consumption was lower but TD&A costs per customer were similar to what they are today.

Because the number of customers in a utility's territory is the single best predictor for annual TD&A costs, our findings indicate that it might be useful for utilities to transition to monthly per-customer fixed charges to recover their annual TD&A costs. This finding is mirrored in recent ratemaking trends amongst investor owned utilities: Nevada Energy and Tucson Electric Power recently moved to increase monthly fixed charges in order to recover TD&A costs as more customers add distributed generation, and reduce their volumetric energy consumption [22,23].

In the future, utilities, regulators, and policymakers should study how utility rates might evolve to recover customer-related TD&A costs as the volume of kWh energy sales decreases. There are significant challenges associated with recovering the costs associated with transmission, distribution, and utility administration without negatively impacting low-income customers or delaying progress toward renewable energy standards and goals. While our analysis and results can be used to understand the general character of TD&A costs amongst investor-owned utilities in the United States, we recommend that each utility analyze its particular cost structure and customer base to design rates that minimize the cost to consumers and ensure an economically sustainable transition to a grid with a larger share of distributed generation in the future. ■

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APPENDIX

A.1 FERC Form 1 Errata

To identify any erroneous data points, we examine the year-to-year change in spending, MW demand, MWh energy sales, and total customers for individual utilities. Any outlying year-to-year changes were investigated by examining the corresponding FERC Form 1 filings by hand using the FERC Form 1 Viewer available on FERC's website [13]. The following data anomalies were identified and corrected:

- A number of utilities erroneously reported monthly peak electricity demand in kW rather than MW. We identified these errors by calculating the load factor during the year and comparing it to load factors from the same utility during previous years. We divide the reported peak demand for the following utility reports by 1000 to convert the kW demand reported into units of MW: Mississippi Power Company, 1997–2002; Orange and Rockland Utilities Company, 1999–2000; Village of Morrisville Water and Light Department, 1999, 2001; Savannah Electric and Power Company, 2000, 2001, 2003; Graham County Electric Cooperative, Inc., 1998–2004; Valley Electric Association Inc., 2004; Vermont Electric Cooperative, Inc., 1999–2003.
- Hawaii Electric Company reported annual energy sales in kWh rather than MWh for years 2005–2008. We identified this error by calculating the average price per MWh for the utility and comparing it to the average price per MWh during previous years. We divide the reported energy sales for these years by 1000 to convert kWh sales into units of MWh.
- Pacific Gas & Electric and Georgia Power Company erroneously reported Administrative and General Maintenance costs for year 2006. We identified these errors by comparing the amounts reported in 2006 to amounts reported in adjacent years. We corrected the erroneous reports for 2006 by using the value "Amount for Previous Year" reported in the utilities' 2007 FERC Form 1.
- Three utilities reported an exceptionally high cost for new distribution system capital infrastructure for an individual year, but reported no other distribution capital costs between 1994–2014. These outlying data either represent a bulk transfer of utility assets or erroneous reports. Because these data are outliers that do not represent usual trends in utility capital spending, we remove the following utility reports: Nantucket Electric Company, 2006; United Power Inc., 2004; Newcorp Resources Electric Cooperative Inc., 2002.

A.2 Transmission Cost Regression Analysis Plots

A.2.1 Transmission Capital Costs

FIGURE A1

The average transmission capital cost during the years 1994–2014 was $75/Customer-Year, though spending did not scale strongly with the number of utility customers.

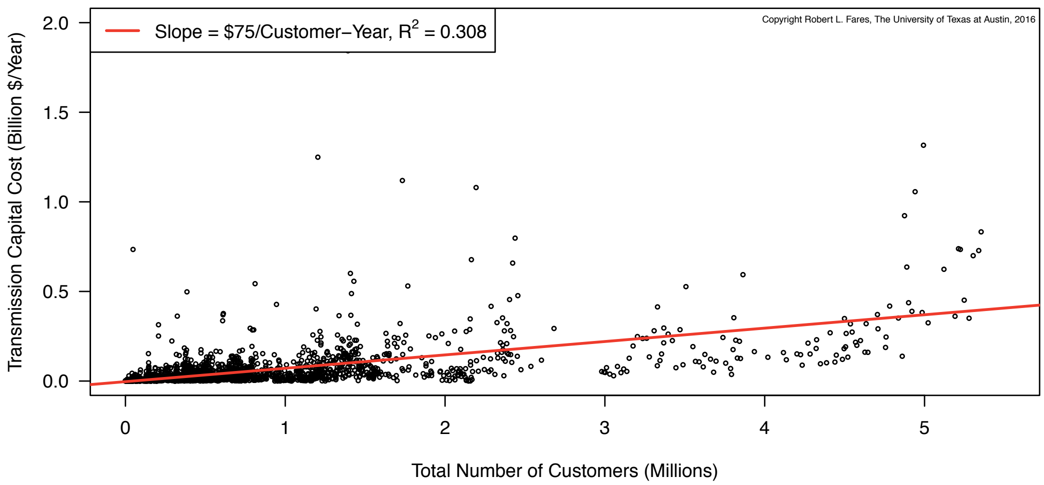


FIGURE A2

The average transmission system capital cost during the years 1994–2014 was $13/kW-Year, though spending did not scale strongly with annual peak demand.

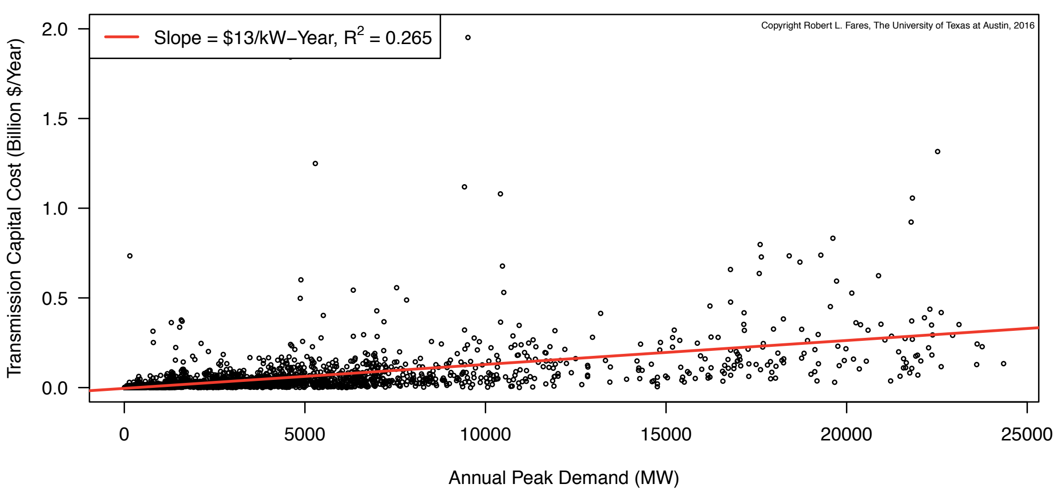
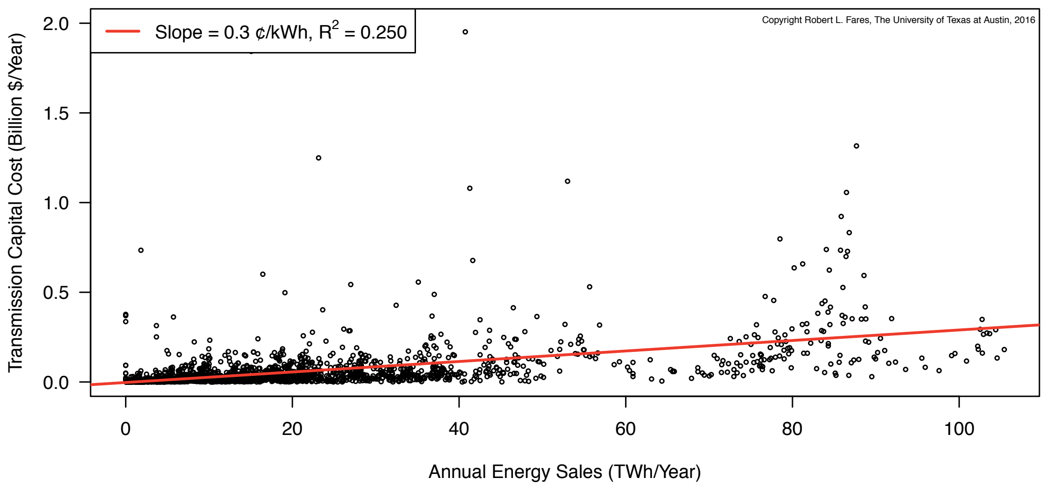


FIGURE A3

The average transmission system capital cost during the years 1994–2014 was 0.3 ¢/kWh, though spending did not scale strongly with annual energy sales.



A.2.2 Transmission Operation and Maintenance Costs

FIGURE A4

We use linear regression to analyze the relationship between the number of customers in a utility's territory and annual transmission system operation and maintenance costs. The average cost during the years 1994–2014 was $45/Customer-Year.

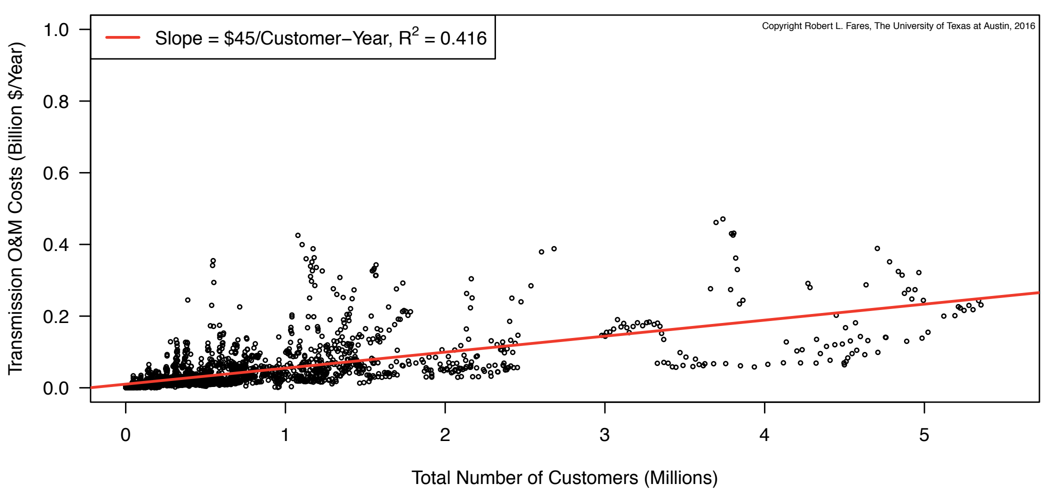


FIGURE A5

We use linear regression to analyze the relationship between a utility's annual peak demand and its annual transmission system operation and maintenance costs. The average cost during the years 1994–2014 was $8/kW-Year.

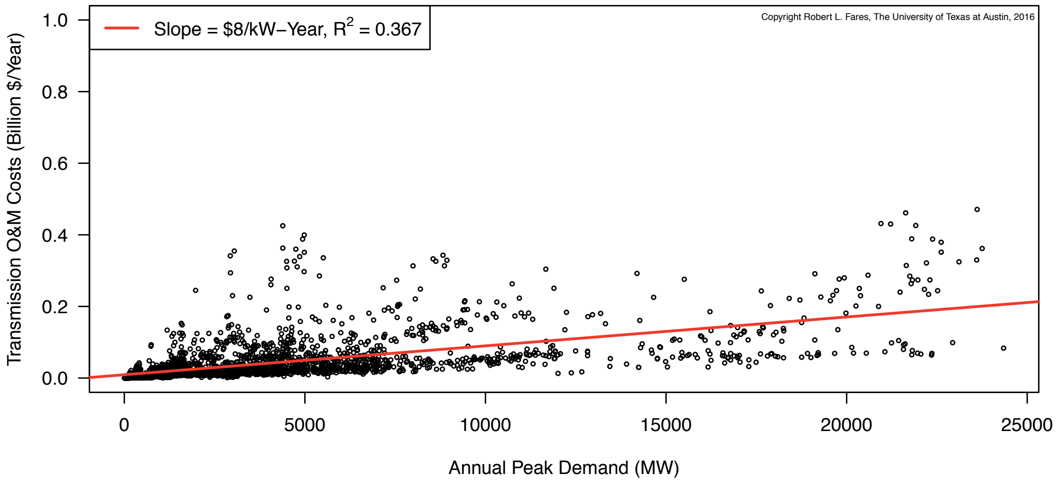
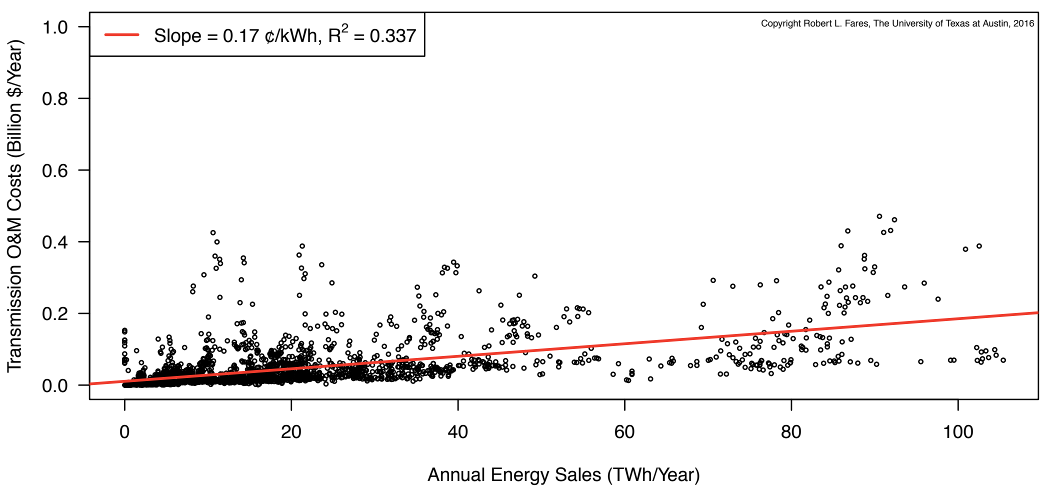


FIGURE A6

We use linear regression to analyze the relationship between a utility's annual energy sales and its annual transmission system operation and maintenance costs. We find the average cost during the years 1994–2014 was 0.17 ¢/kWh.



A.2.3 Total Transmission System Costs

FIGURE A7

We use linear regression to analyze the relationship between the number of customers in a utility's territory and total annual transmission system costs. The average cost for capital infrastructure, operation, and maintenance during the years 1994–2014 was $119/Customer-Year.

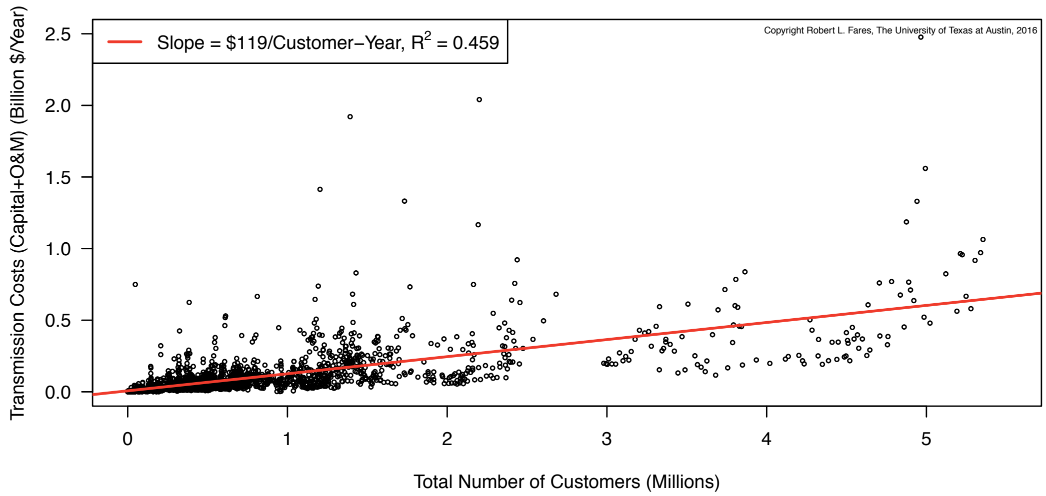


FIGURE A8

We use linear regression to analyze the relationship between a utility's annual peak demand and its total annual transmission system costs. The average cost for capital infrastructure, operation, and maintenance during the years 1994–2014 was $21/kW-Year.

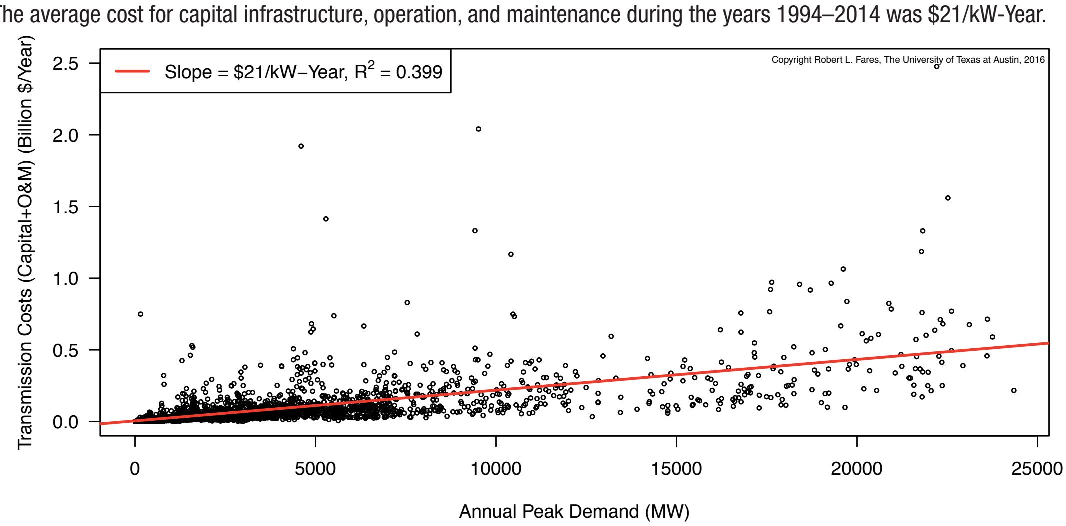
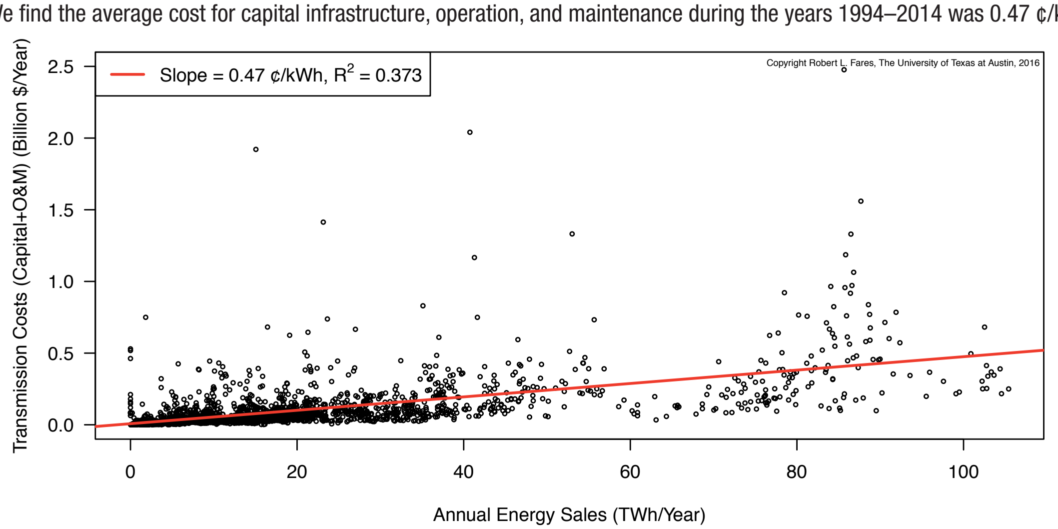


FIGURE A9

We use linear regression to analyze the relationship between a utility's annual energy sales and its total annual transmission system costs. We find the average cost for capital infrastructure, operation, and maintenance during the years 1994–2014 was 0.47 ¢/kWh.



A.3 Distribution Cost Regression Analysis Plots

A.3.1 Distribution Capital Costs

FIGURE A10

We perform a linear regression with spending on new distribution capital infrastructure as the outcome variable and the number of utility customers as the predictor variable. It is found that the average distribution capital cost during the years 1994–2014 was $189/Customer-Year.

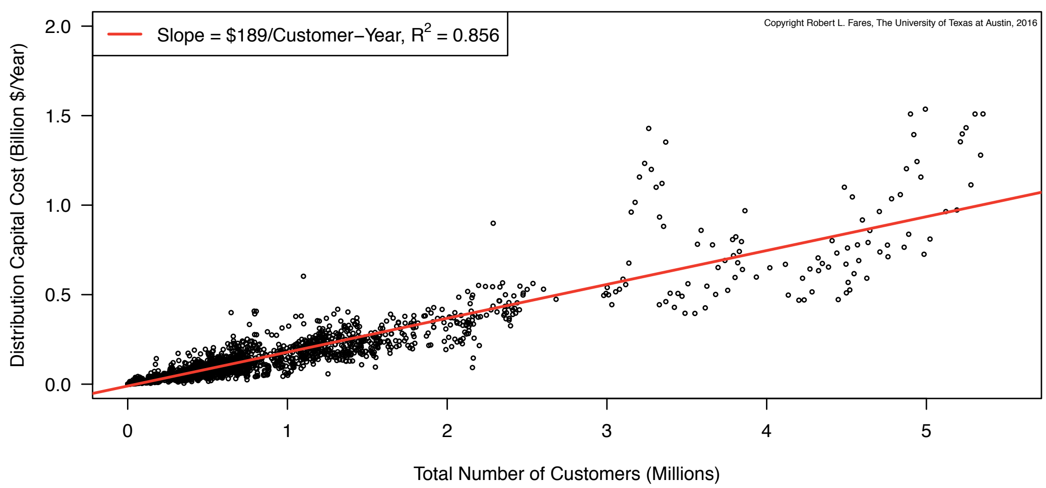


FIGURE A11

We perform a linear regression with spending on new distribution capital infrastructure as the outcome variable and the utility's annual peak demand as the predictor variable. It is found that the average distribution capital cost during the years 1994–2014 was $34/kW-Year.

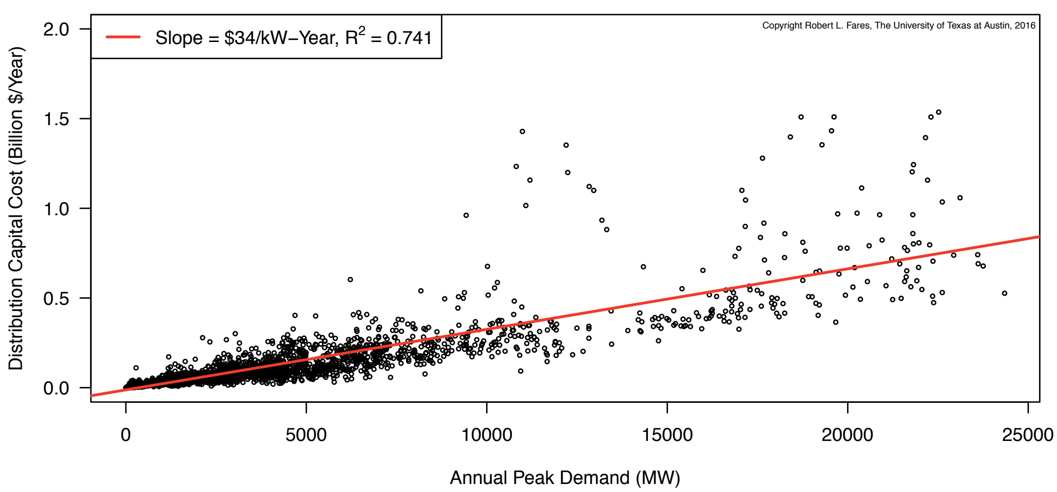
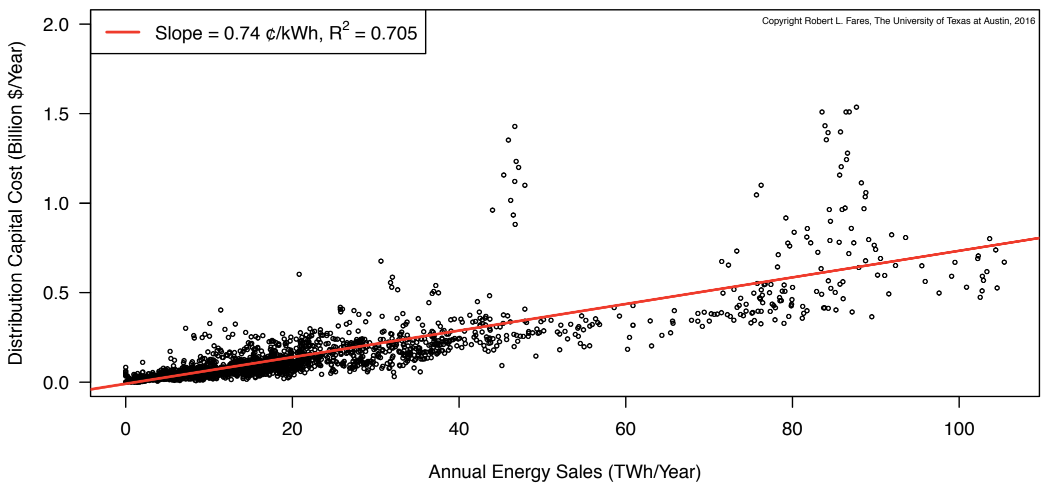


FIGURE A12

We perform a linear regression with spending on new distribution capital infrastructure as the outcome variable and the annual energy sales as the predictor variable. It is found that the average distribution capital cost during the years 1994–2014 was 0.74 ¢/kWh.



A.3.2 Distribution Operation and Maintenance Costs

FIGURE A13

We use linear regression to analyze the relationship between the number of customers in a utility's territory and annual distribution system operation and maintenance costs. We find the average cost is $102/Customer-Year.

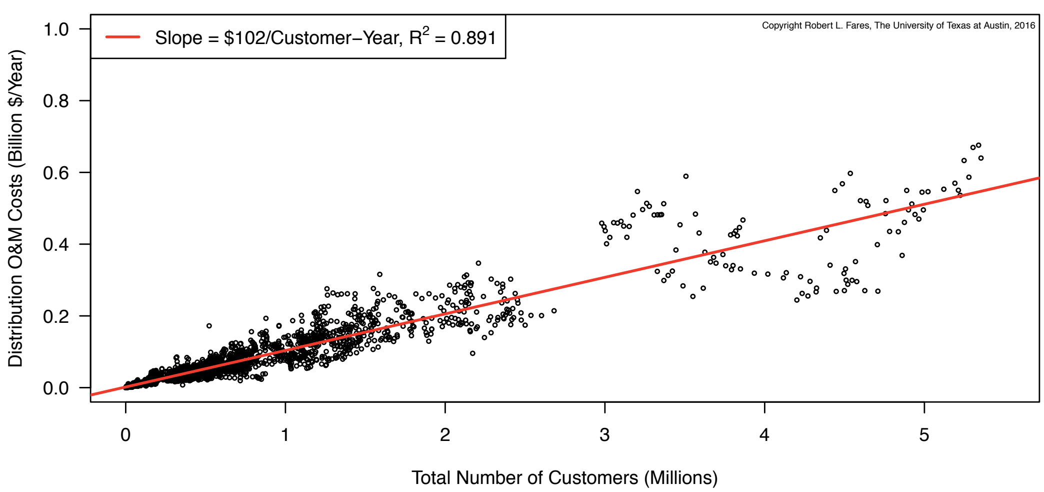


FIGURE A14

We use linear regression to analyze the relationship between the number of customers in a utility's territory and annual distribution system operation and maintenance costs. We find the average cost is $18/kW-Year, though peak demand is a worse predictor for operation and maintenance costs than the number of utility customers.

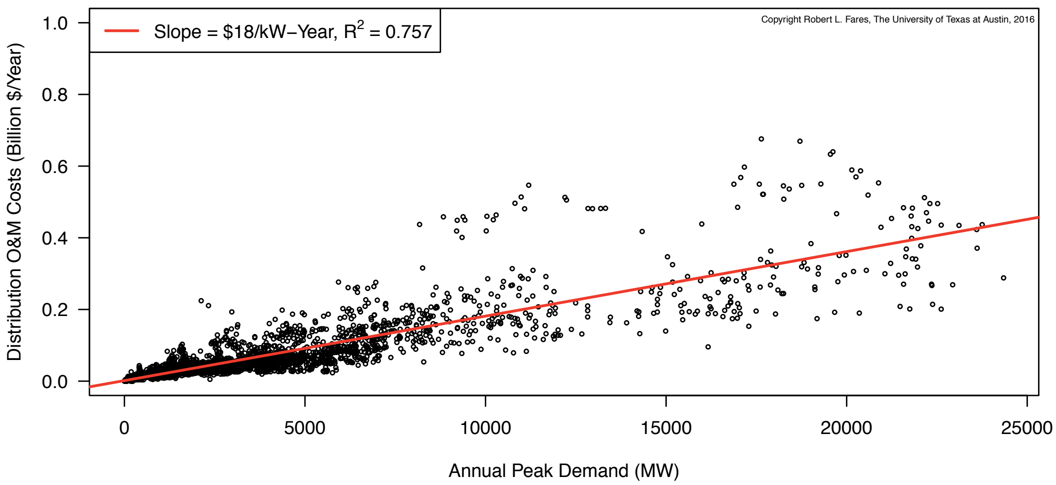
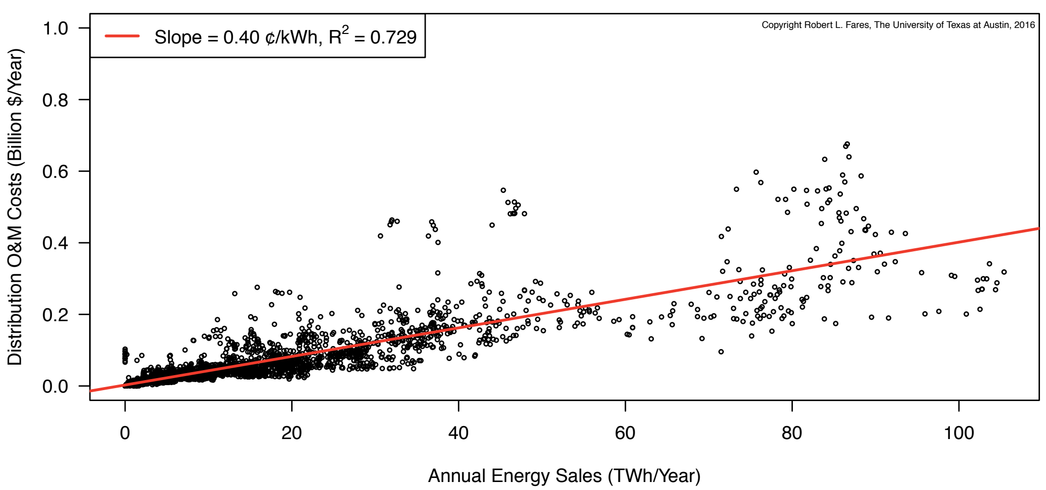


FIGURE A15

We use linear regression to analyze the relationship between the number of customers in a utility's territory and annual distribution system operation and maintenance costs. We find the average cost is 0.40 ¢/kWh, though annual energy sales is a worse predictor for operation and maintenance costs than the number of utility customers.



A.3.3 Total Distribution System Costs

FIGURE A16

Here we show the total annual cost for electricity distribution versus the number of customers in a utility's territory. The total annual cost of electricity distribution during the years 1994–2014 was approximately $291 per customer per year.

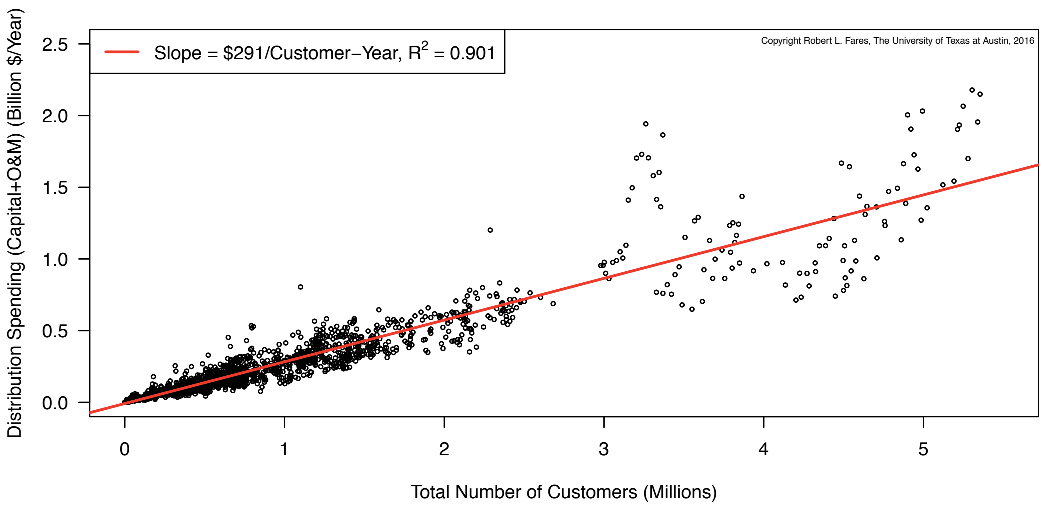


FIGURE A17

Here we show the total annual cost for electricity distribution versus a utility's annual peak demand. The total annual cost of electricity distribution during the years 1994–2014 was approximately $52 per kW of peak demand per year.

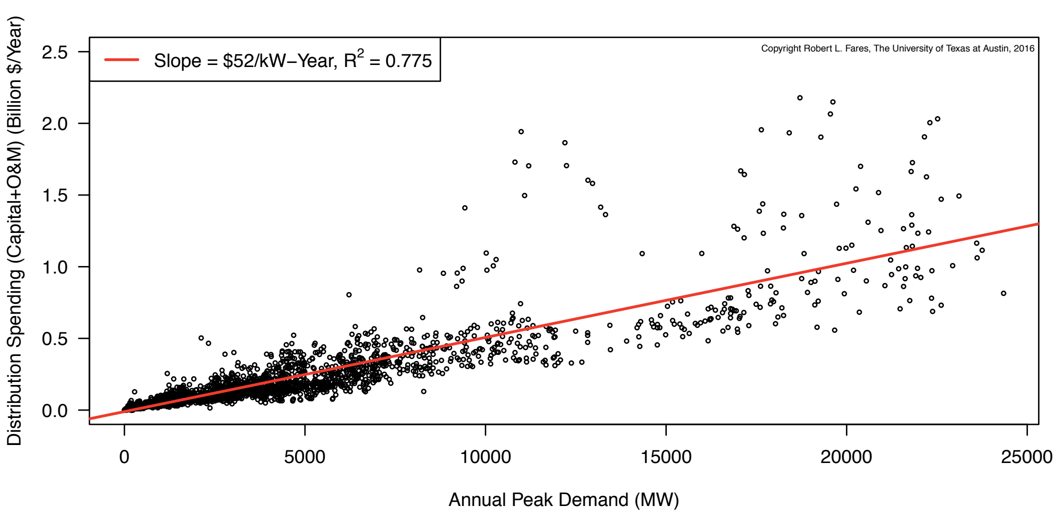
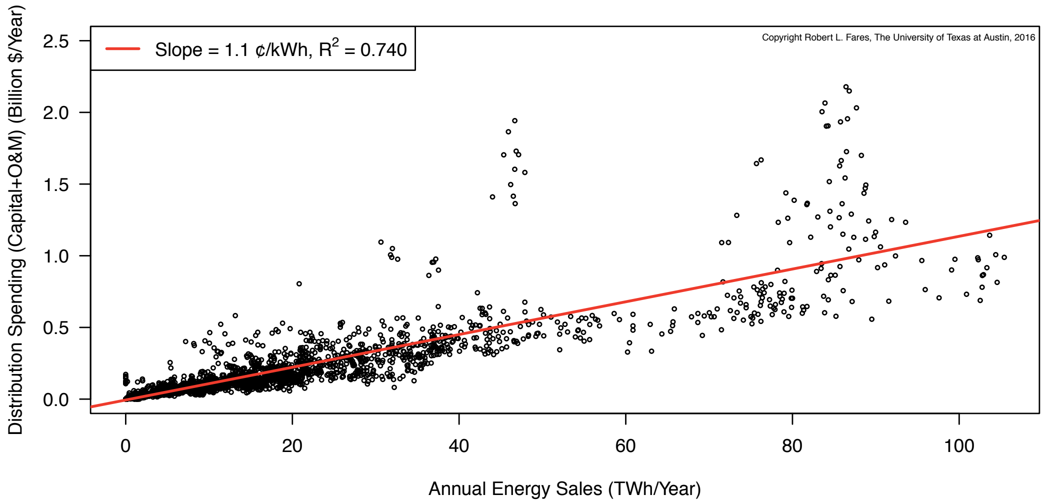


FIGURE A18

Here we show the total annual cost for electricity distribution versus a utility's annual energy sales. The total annual cost of electricity distribution during the years 1994–2014 was approximately 1.1 ¢ per kWh of energy sold.



A.4 Utility Administrative Costs

A.4.1 Administrative Capital Costs

FIGURE A19

Annual expenses on new administrative capital infrastructure do not scale strongly with the number of customers in a utility's territory. The average cost during the years 1994–2014 was $40/Customer-Year.

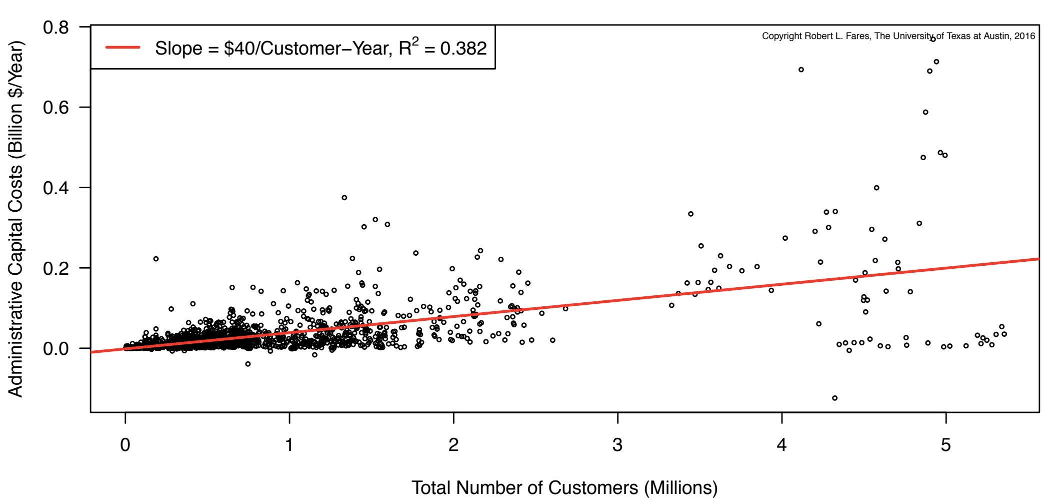


FIGURE A20

Annual expenses on new administrative capital infrastructure do not scale strongly with a utility's peak electricity demand. The average cost during the years 1994–2014 was \$7.9/kW-Year.

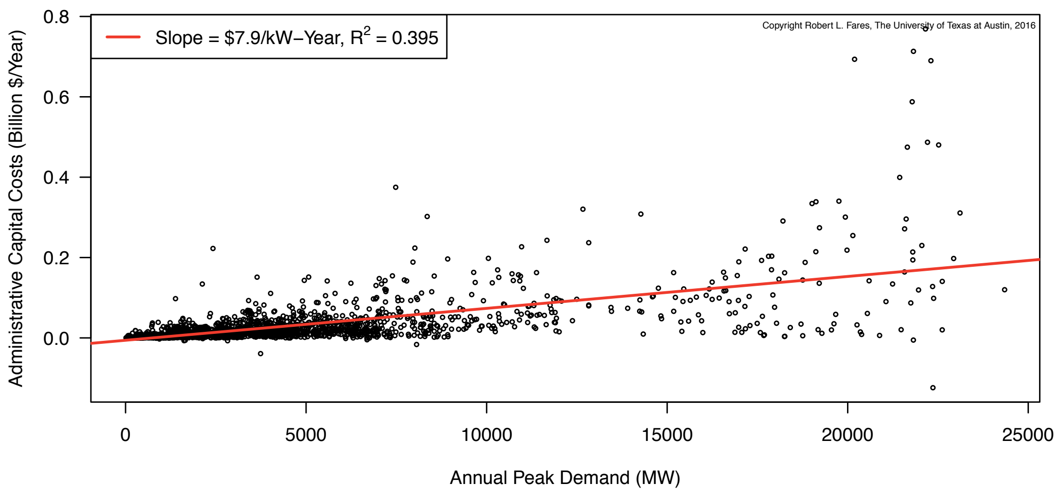
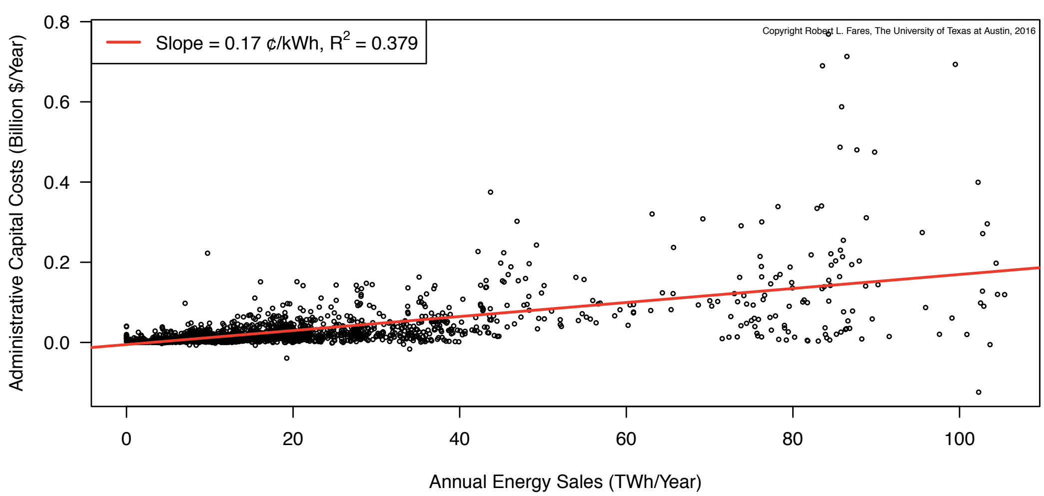


FIGURE A21

Annual expenses on new administrative capital infrastructure do not scale strongly with a utility's annual energy sales. The average cost during the years 1994–2014 was 0.17 ¢/kWh.



A.4.2 Utility Administrative Operation and Maintenance Costs

FIGURE A22

Annual administrative operation and maintenance expenses scale strongly with the number of customers in a utility's territory. The average cost during the years 1994–2014 was $293/Customer-Year.

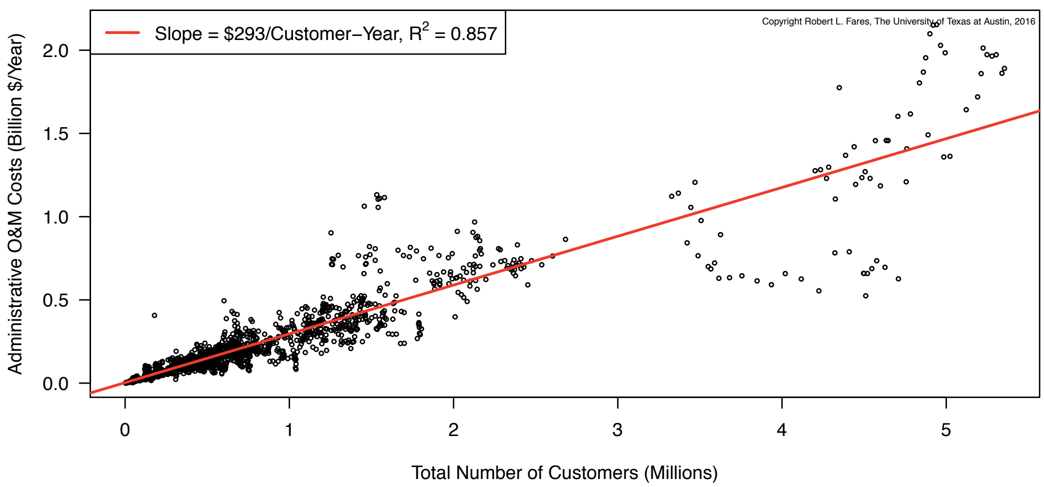


FIGURE A23

Annual administrative operation and maintenance expenses scale less strongly with annual peak demand than with the number of customers in a utility's territory. The average cost during the years 1994–2014 was $53/kW-Year.

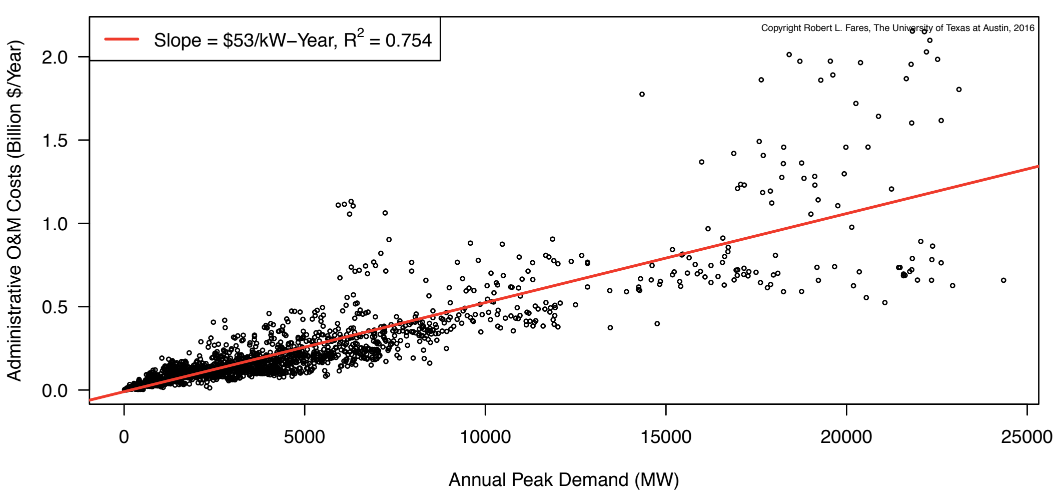
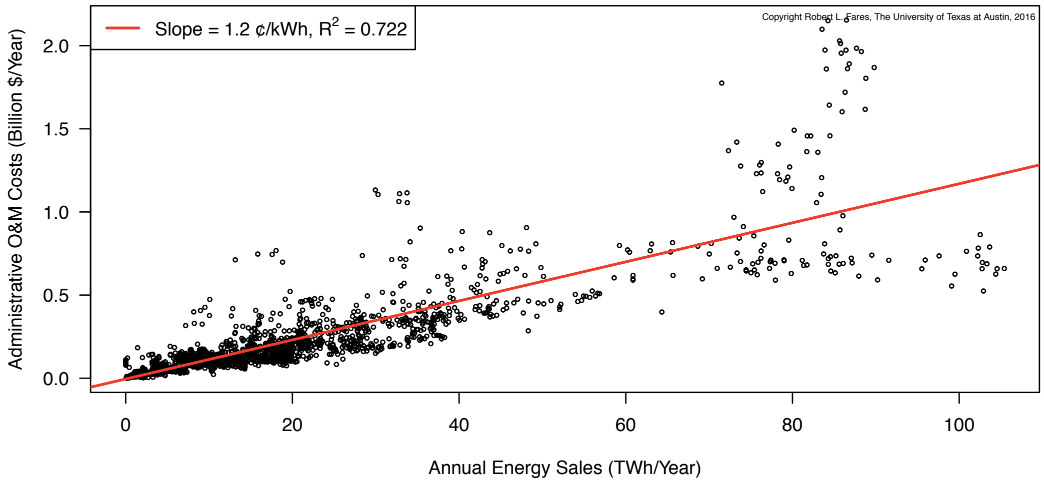


FIGURE A24

Annual administrative operation and maintenance expenses scale less strongly with annual energy sales than with the number of customers in a utility's territory. The average cost during the years 1994–2014 was 1.2 ¢/kWh.



A.4.3 Total Utility Administrative Costs

FIGURE A25

Total annual administrative capital, operation, and maintenance costs scale strongly with the number of customers in a utility's territory. The average cost during the years 1994–2014 was $333/Customer-Year.

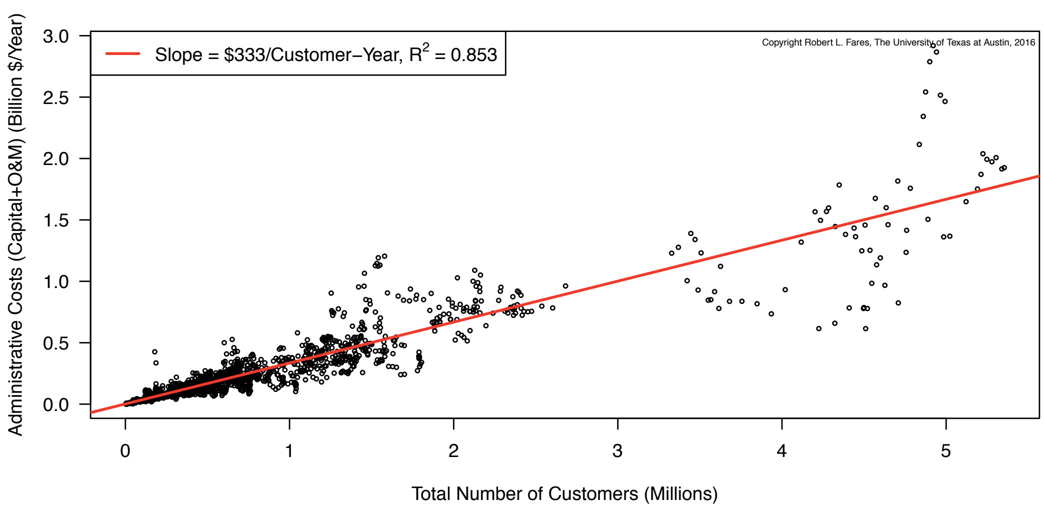


FIGURE A26

Total annual administrative capital, operation, and maintenance costs scale less strongly with annual peak demand than with the number of customers in a utility's territory. The average cost during the years 1994–2014 was $61/kW-Year.

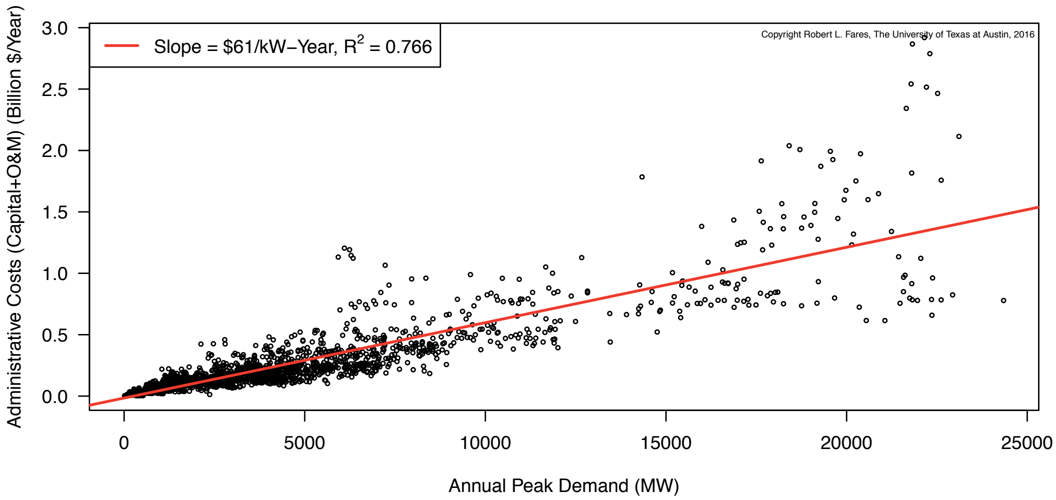
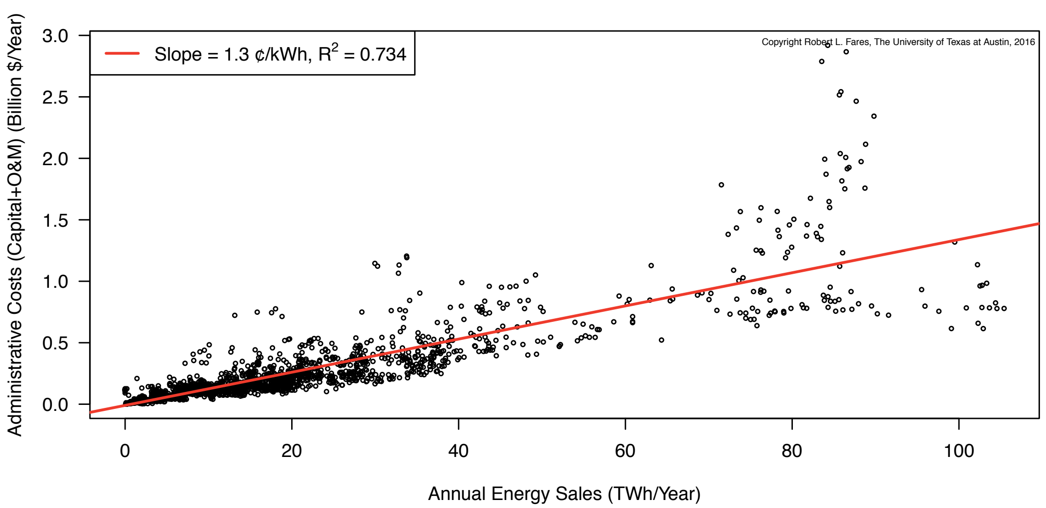


FIGURE A27

Total annual administrative capital, operation, and maintenance costs scale less strongly with annual energy sales than with the number of customers in a utility's territory. The average cost during the years 1994–2014 was 1.3 ¢/kWh.



A.5 Variation in Energy Consumption Per Customer Over Time

FIGURE A28

The average energy consumption per utility customer (with residential, commercial, and industrial customers pooled) increased dramatically after 1960, but has not varied significantly since 1980.

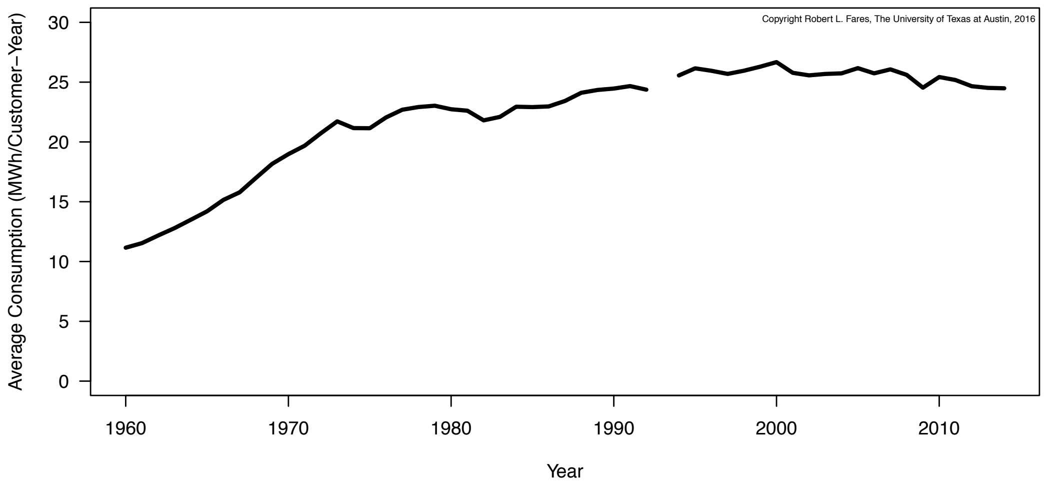


FIGURE A29

The average energy consumption per residential customer increased dramatically between 1960 and the mid 1970s, but has only increased gradually since then.

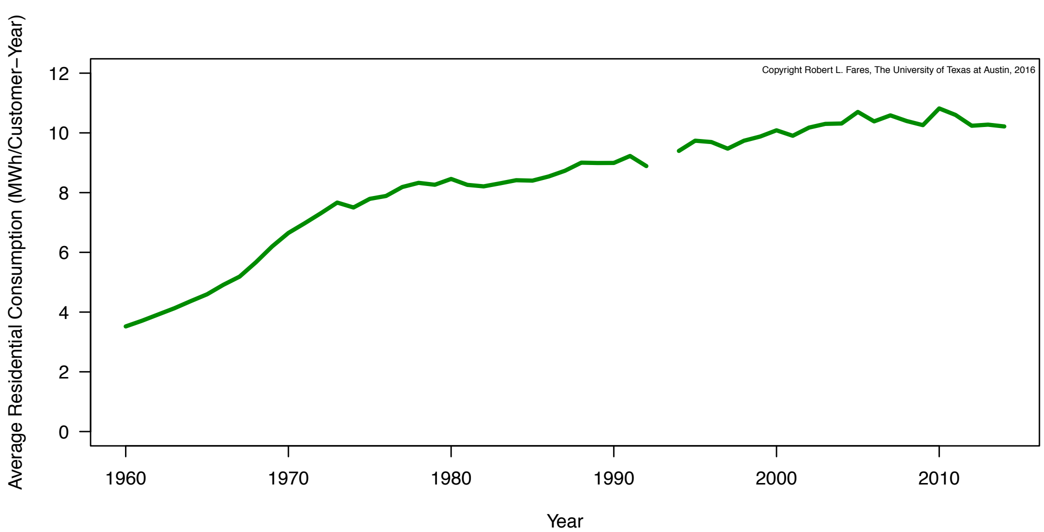


FIGURE A30

The average energy consumption per commercial customer increased very quickly between 1960 and the mid 1970s, and then more gradually until the early 1990s. Since then, commercial energy consumption per customer has remained roughly constant.

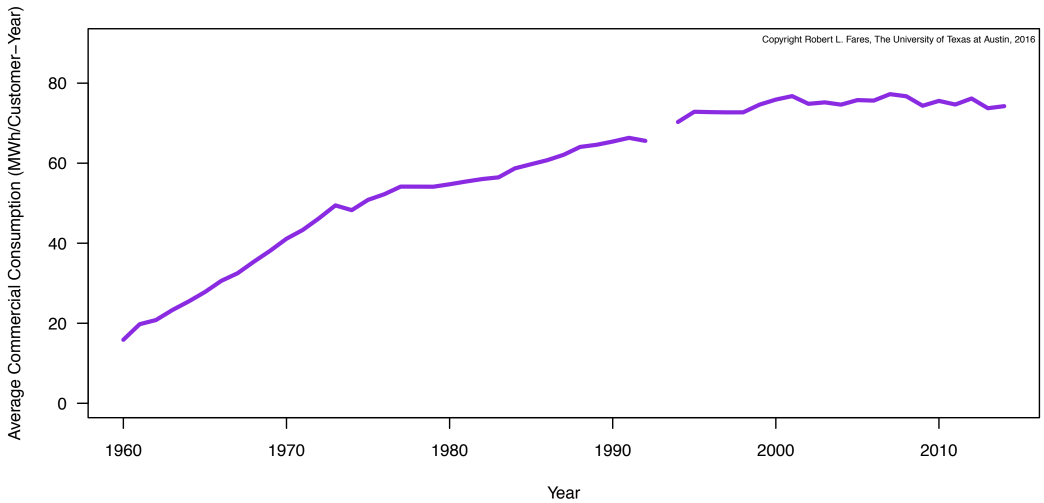
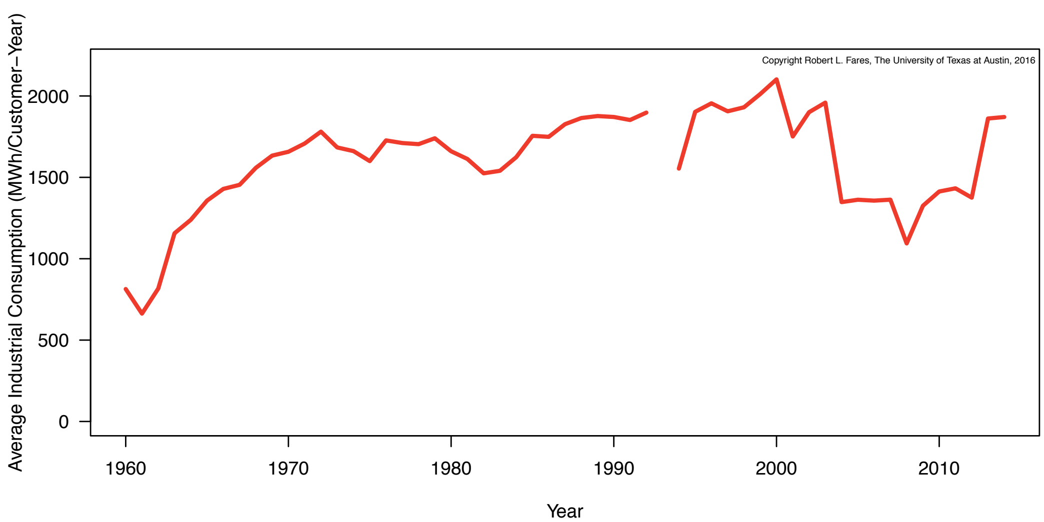


FIGURE A31

The average energy consumption per industrial customer increased dramatically between 1960 and the early 1970s, and dipped significantly in the 2000s. In 2014, the average energy consumption per industrial customer was similar to levels observed from 1970–2000.



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