Electricity Pricing to U.S. Manufacturing Plants, 1963-2000

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Abstract

There is tremendous dispersion in the electricity prices paid by manufacturers, as we show, greater than the dispersion in production worker wages. We also document a dramatic compression in the log price distribution between 1967 and 1977, which we trace to a sharp erosion of quantity discounts. Spatial dispersion in average electricity prices among states, counties and utility service territories is also large. The spatial sorting of electricity-intensive manufacturing activity to areas with cheaper electricity is modest, but it increases after 1973, apparently in response to a shift from falling to rising real electricity prices.

To estimate the role of cost factors and markups in quantity discounts, we exploit differences among utilities in the purchases distribution of their customers. The estimation results reveal that supply costs per watt-hour fall by more than half over the range of purchases in the data, regardless of time period. Prior to the mid 1970s, marginal price and marginal cost schedules with respect to purchase quantity are nearly identical, remarkably in line with efficient pricing. In later years, marginal supply costs exceed marginal prices for smaller manufacturing customers by 10-20%. The data provide no support for a Ramsey-pricing interpretation of quantity discounts.

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1. Introduction

Longstanding concerns and recent developments have combined to intensify interest in the performance of the U.S. electric power industry. These include persistent regional disparities in retail prices, growth in wholesale power markets, a wave of restructuring and deregulation initiatives in the 1990s, difficulties in the transition to a more competitive electricity sector, and, perhaps most spectacularly, the California electricity crisis of 2000-2001.[1] Despite these concerns and developments, we lack broad empirical studies of electricity prices paid by end users, and there are major gaps in our knowledge of retail pricing patterns and their evolution over time. These gaps hamper efforts to place recent developments in historical perspective, to evaluate the impact of regulatory changes on electricity users, and to assess theories of public utility pricing.

To help address these issues, we construct a rich micro database – Prices and Quantities of Electricity in Manufacturing (PQEM) – and use it to study electricity pricing to U.S. manufacturing plants from 1963 to 2000. The PQEM includes data on electricity expenditures, purchases (watt-hours) and other variables for more than 48,000 manufacturing plants per year, linked to additional data on the utilities that supply electricity. Our customer-level data are limited to manufacturers, but they are informative about pricing practices for a broader class that includes other industrial customers and large and mid-size commercial customers.[2]

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[1] Hirsh (1999), EIA (2000b), Besanko et al. (2001), Borenstein (2002), and Joskow (2005), among others, describe and analyze these matters. Joskow and Schmalensee (1983) anticipate many of the pitfalls and challenges that have confronted reform efforts in the electricity sector.

[2] We inspected electricity tariffs for several utilities and found that they offered the same menu of electricity pricing terms to manufacturers, other industrial customers, and large and mid-size commercial customers. In addition, average electricity prices for the manufacturing sector behave similarly to average prices for the industrial sector as a whole, as we show below. Industrial purchasers account for 45% of retail electricity sales (watt-hours) in 1963 and 31% in 2000 (EIA, 2003(a), Table 8.5). In turn, manufacturing plants account for the lion’s share of electricity purchases by the industrial sector.

Figure 1 displays several measures of dispersion in the distribution of log electricity prices from 1963 to 2000.[3] The price measure is the ratio of the plant's annual expenditures on purchased electricity to its annual purchases (watt-hours). The figure shows purchase-weighted and shipments-weighted price distributions, where the former weights each plant-level observation by watt-hours of electricity purchases, and the latter weights by output as measured by shipments.[4] As seen in Figure 1, there is tremendous dispersion in the electricity prices paid by manufacturing plants. The purchase-weighted standard deviation exceeds 38% in all years and reaches 55% in some years. For perspective, compare this measure to analogous measures of wage dispersion. On an hours-weighted basis, the standard deviation of log hourly wages among manufacturing workers ranges from 44% to 54% between 1975 and 1989, and the standard deviation of log hourly production worker wages among manufacturing plants ranges from 39% to 43% between 1975 and 1993.[5] In other words, the dispersion in electricity prices among manufacturing plants is as great as wage dispersion among manufacturing workers and greater than wage dispersion among plants.

Figure 1 also reveals that the log price distribution underwent a great compression from 1967 to the late 1970s. The between-plant standard deviation fell from 55% in 1967 to 44% in 1979 on a purchase-weighted basis and from 47% to 35% on a shipments-

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[3] The natural log transformation is convenient for characterizing the magnitude of price differences and price dispersion. In addition, electricity transmission over power lines and the process of transforming voltage levels involve costs in the form of electrical energy dissipated as heat energy. The dissipation of electrical energy rises with transmission distance, other things equal, so that spatial price differentials are aptly described in log terms. For these reasons, we often consider log price differentials in this paper, but we also consider prices measured in natural units.

[4] These weighting methods mirror the use of input-weighted and output-weighted distributions in studies that quantify between-plant and within-plant components of productivity growth. Examples include Foster et al. (2001) and van Biesebroeck (2004).

[5] Figure 1 in Davis and Haltiwanger (1991) reports a time series derived from Current Population Survey data for the standard deviation of log hourly wages among manufacturing workers. For wage dispersion

weighted basis. Over the same time frame, the 90-10 price differential shrank by about 37 log points under both weighting methods. The 90-10 differential later widened but never returned to the peaks of the 1960s. To the best of our knowledge, this study is the first to quantify the remarkable extent of electricity price dispersion for a major end-user group and the first to document the great compression that played out by the late 1970s.

We show below that the great compression episode reflects a sharp erosion of quantity discounts. On a purchase-weighted basis, the average elasticity of price with respect to a plant's annual purchase quantity declined sharply in magnitude from about -22% in 1967 to about -9% in the late 1970s, partially recovering after the mid 1980s. Because the range of electricity purchases among manufacturers is enormous, these elasticities translate into very large price differentials. For example, prices for the few dozen biggest purchasers were two-thirds below the median price in the 1960s. Plant-level differences in purchase amounts account for 75% of overall price dispersion among manufacturers in 1963 but only 30% by 1978.

Quantity discounts in the form of declining-block tariffs are a well-known feature of retail electricity pricing for industrial and commercial customers and a sometimes contentious topic in ratemaking proceedings and legislative hearings.[6] They are also the object of careful analysis in theoretical treatments of nonlinear pricing (e.g., Wilson, 1993) and public utility pricing in particular (e.g., Brown and Sibley, 1986). Insofar as the cost of supplying electrical power declines with a customer's purchase quantity, an

among plants, we calculated the hours-weighted between-plant standard deviation of the log of average hourly wages using PQEM data on annual hours and annual labor costs for production workers.

[6] Cudahy and Malko (1976) discuss quantity discounts and other aspects of rate design from the perspective of public utility regulators in a prominent case involving the Madison Gas & Electric Company. Hirsh (1999) recounts the political struggles over federal legislative efforts to reform rate-making practices, efforts that culminated in the Public Utilities Regulatory Policies Act (PURPA) of 1978, a major component of President Carter's National Energy Plan.

efficient two-part tariff or other marginal-cost pricing scheme requires quantity discounts. If demand is also more elastic at higher purchase levels, Ramsey pricing by a revenue-constrained public utility entails lower markups for bigger customers and, hence, is another potential explanation for quantity discounts.

These cost and demand determinants of quantity discounts are well understood as a matter of theory, but their importance in practice is unclear. Brown and Sibley (1986) and Borenstein and Holland (2003), for example, argue that the approach to rate setting by electric utilities and their regulators, as well as the resulting tariff schedules, do not seem well designed to achieve efficient pricing. In addition, previous research offers no quantitative, theoretically grounded explanation for the sharp erosion in quantity discounts that we document. To address these matters, we propose and implement a novel method for estimating the contribution of cost factors and price markups to quantity discounts. In particular, we exploit the considerable variation across electric utilities in the size distribution of customer purchases to estimate how supply costs per watt-hour vary with customers' annual purchase quantities. The results reveal that supply costs fall by more than half in moving from smaller to bigger purchasers. This pattern holds throughout the past four decades, providing a clear and powerful cost-based rationale for quantity discounts.

We also use the estimated price and supply cost schedules to construct marginal prices and marginal costs with respect to customer purchase quantity. We find no support for the Ramsey-pricing view that quantity discounts reflect smaller markups over marginal cost for more elastic demanders. In contrast, we find strong support for efficient pricing in the early years of our sample. Indeed, marginal cost and marginal price curves are nearly identical prior to the mid 1970s. In the upper half of the customer purchase distribution, they are nearly identical throughout the period from 1967 to 2000. Among smaller manufacturing customers, however, the pricing structure begins to deviate from efficiency after 1973. From 1981 onwards, marginal supply costs for smaller manufacturing customers exceed marginal costs by 10-20%.

We also consider the spatial distribution of electricity prices among states, counties and utility service territories. In part, we are motivated by the question of whether growth in wholesale power markets caused spatial price differentials to diminish. It turns out that measured trends in spatial price dispersion are highly sensitive to how we weight customer-level observations. On a shipments-weighted basis, price dispersion across counties exhibits an upward trend until the early 1990s. On a purchase-weighted basis, price dispersion across counties shows a strong downward trend throughout the past four decades, including the period that predates the growth of wholesale power markets. This sensitivity of spatial dispersion trends to weighting method is a consequence of changing quantity discounts and the highly skewed distribution of electricity purchases. In fact, when we exclude the roughly 20-50 manufacturing plants per year with annual purchases in excess of 1,000 gigawatt-hours, the purchase-weighted dispersion of electricity prices across counties shows no downward trend until the early 1980s, and a much more modest downward trend since the early 1980s.

Given the magnitude of spatial price differentials, there is clearly a cost motive for electricity-intensive manufacturers to locate in areas with relatively cheap electricity. We show that this type of spatial sorting makes a modest contribution to the overall negative relationship between price and purchase quantity in the pooled dataset. We also provide evidence that the switch from falling to rising real electricity prices after 1973 precipitated a greater spatial sorting of production activity.

The paper proceeds as follows. Section 2 reviews selected economic and regulatory developments in the electric power industry. Section 3 describes the PQEM database. Section 4 quantifies the dispersion of electricity prices between and within industries, states, counties, utilities, and purchase size classes. Section 5 discusses cost and demand influences on electricity pricing, describes key features of electricity tariff schedules, and develops evidence on electricity price-quantity schedules and their evolution over time. Section 6 evaluates the role of spatial sorting and other behavioral responses by customers that contribute to a negative relationship between electricity price and purchase quantity. Section 7 estimates supply costs as a function of customer purchase levels, then applies the supply schedules to evaluate whether cost factors can explain quantity discounts and their evolution over time. Section 8 considers marginal price and marginal cost curves and investigates whether they comport with efficient pricing and Ramsey pricing. Section 9 summarizes our main findings and identifies several questions and implications for future research.

2. Some Background

From its inception in the 1880s until the mid 1960s, the electric power industry enjoyed a "golden era" in which generating technology improved rapidly, capacity was plentiful, and electricity prices fell.[7] Utilities offered promotional block pricing whereby the price per kilowatt-hour (kWh) declined with purchase amounts. Stimulated by falling

[7] This view, widely shared by knowledgeable observers, is articulated at length in Hirsh (1999). Joskow (1989) puts it this way: "During the 1950s and most of the 1960s the electric power industry attracted little attention from public policy makers. It experienced high productivity growth, falling nominal and real prices, excellent financial performance, and little regulatory or political controversy."

real prices, quantity discounts, and new electrical appliances and machinery, electricity consumption grew rapidly after World War II (Hirsh, 1989, Chapter 4). This golden era drew to a close by the late 1960s as unforeseen technological and metallurgical barriers hampered progress in the creation of better electric generators.[8]

Economic factors in the 1970s exacerbated the technological problems facing the industry. Uncertain demand, the high cost of electricity storage and, historically, the absence of peak-load pricing at the retail level made it difficult to project electricity consumption and generating requirements. Accurate projections became more difficult in the 1970s because of large fluctuations in economic activity and in energy input costs. Prices rose sharply for coal and oil, major fuel sources for electricity generation, and there were big disruptions in petroleum supplies. The OPEC Oil Embargo of 1973 precipitated a dramatic rise in oil prices, as did the Iranian Revolution of 1979.

Several regulatory developments added to cost pressures and tightened capacity constraints. Concerns about air and water pollution from conventional power plants and about safety at nuclear power plants led to several pieces of legislation in the late 1960s and 1970s that raised costs and hampered the operation and development of the electricity industry.[9] The National Environmental Policy Act of 1969 required utilities to prepare and defend environmental impact statements for new generator sites. The Clean Air Act of 1970 restricted air pollutants at electricity-generating plants and encouraged utilities to switch from coal to cleaner burning oil or natural gas. The Federal Water Pollution Control Act of 1972 limited waste discharge, and the Resource Conservation and Recovery Act of 1976 set forth standards for utility waste products. The Energy

[8] Chapters 7 and 8 in Hirsh (1989) provide a detailed discussion of the technological difficulties that confronted the electric power industry in the late 1960s and the 1970s.

Supply and Environmental Coordination Act of 1974 authorized the federal government to prohibit purchases of natural gas and petroleum by utilities. The Clean Air Act Amendments of 1977 imposed more stringent restrictions on emissions from electricity-generating plants.

In 1978, several major pieces of legislation passed as part of President Carter's National Energy Plan. The plan included the gradual removal of price controls on oil and natural gas, restrictions on the use of oil and natural gas by electricity generating plants, and rate reform provisions for electric utilities. The Public Utilities Regulatory Policies Act (PURPA) of 1978 had the biggest impact on the electricity sector.[10] Its rate-reform provisions were hotly contested in Congress (Joskow, 1979 and Hirsh, 1999) but, in their final form, required that state regulatory authorities merely "consider" various reforms that included an end to promotional pricing structures. In addition, PURPA Section 210 required utilities to buy from and sell power to "qualifying facilities." The goal was to draw non-utilities, such as cogeneration plants and renewable resource plants, into the electric power market. In this respect, PURPA and later legislation had a major impact. By 1999, non-utilities owned 19.8 percent of the electric generating capacity in the U.S. (EIA, 2000a, p.1).

The effect of these technological, economic and regulatory developments on retail electricity prices can be seen in Figure 2, which plots the average real price per kilowatt-hour (kWh) for major end-user sectors.[11] Real electricity prices ceased falling in 1970,

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[9] See Appendix A of EIA (2000b) for a detailed description of legislation summarized in this paragraph.
[10] See Joskow (1989, pages 127-128), White (1996, pages 206-207), and Chapters 4 and 5 in Hirsh (1999). Hirsh (1999) and Gordon (1982) provide extensive discussion of PURPA.
[11] The electricity price series in Figure 2 for the residential, commercial and industrial sectors are from the Energy Information Administration (EIA), and the two series for the manufacturing sector are constructed from the PQEM. The EIA data rely on reports from electric utilities, and the PQEM data rely on reports from electricity customers (manufacturing plants). EIA prices are calculated as revenue from retail

and they began to rise after 1973, partly because of sharply higher costs for the fossil fuels that powered many of the generating plants. Real electricity prices continued to rise for about ten years, before resuming a pattern of steady declines.

Wholesale trade in electricity markets expanded rapidly in the 1990s, stimulated by legislative and regulatory policy changes. The Energy Policy Act of 1992 (EPACT) sought to promote greater competition and participation in wholesale markets and to unbundle the sale of electric power from transmission and distribution services (White, 1996 and Besanko et al., 2001). PURPA Section 210, FERC Orders 888 and 889 (issued in 1996) and various state-level actions during the 1990s also stimulated growth in the wholesale trade of electricity. These legislative and regulatory actions helped to create a new class of power producers (non-utility qualifying facilities) with secure access to transmission facilities and exemption from many of the traditional restrictions on public utilities. Sales of electricity for resale rose from 41% of generated power in 1991 to 61% in 2000 (EIA, 2003b, Tables ES and 6.2).

In recent years, several states have undertaken efforts, not always successful, to introduce greater retail competition in the electricity sector. According to Joskow (2005), the "first retail competition programs began operating in Massachusetts, Rhode Island and California in early 1998 and spread to about a dozen states by the end of 2000." These developments on the retail side of the electric power industry come at the tail end of the period covered by our data.

electricity sales divided by kilowatt hours delivered to retail customers. Real prices are calculated using the BEA implicit price deflator for GDP (1996 = 100). In the EIA data, the industrial sector encompasses manufacturing, mining, construction and agriculture.

3. The PQEM Database

The PQEM database derives principally from the U.S. Census Bureau's Annual Survey of Manufactures (ASM) and various data files provided by the Energy Information Administration (EIA). We draw our data on electricity prices and quantities and other variables for individual manufacturing plants from ASM micro files for 1963, 1967, and 1972-2000. The ASM is a series of nationally representative, five-year panels that are refreshed by births as a panel ages. Large manufacturing plants with at least 250 employees are sampled with certainty, and smaller plants with at least 5 employees are sampled randomly with probabilities that increase with the number of employees.[12] ASM plants account for about one-sixth of all manufacturing plants and about three-quarters of manufacturing employment. Our statistics make use of ASM sample weights, so that our results are nationally representative.

ASM plants report expenditures for purchased electricity during the calendar year and annual purchases (kWh). As mentioned above, we calculate the plant-level price as expenditures on purchased electricity divided by quantity purchased. The ASM also contains county and state codes that we use to assign manufacturing plants to electricity suppliers. As described in a companion paper (Davis et al., 2005), we identified and resolved several issues with ASM electricity price and quantity measures in the course of preparing this study. We also cross-checked the ASM data against the Manufacturing

[12] The number of employees required to be a certainty case is lower in 1963 and 1967. In 1963, all plants in a multi-plant firm with 100 or more employees were sampled with certainty. The same was true in 1967 except for plants in apparel (SIC 23) and printing and publishing (SIC 27), which had certainty thresholds of 250 employees.

Energy Consumption Survey, another plant-level data source at the U.S. Bureau of the Census that relies on a different survey.[13]

We merged ASM plants to their electricity suppliers using the Annual Electric Utility Reports, also known as the EIA-861 files. These files include each utility's revenue from sales to industrial customers (by state) and a list of the counties in which the utility has industrial customers. For most counties, the EIA-861 data do not determine a unique assignment of manufacturing plants to electricity suppliers.[14] To address this issue we created a "best-match" utility indicator for each county. Given a list of utilities with industrial customers in the county, the indicator selects the utility with the most statewide revenues from sales to industrial customers. Based on each manufacturing plant's county of operation, we then assign it to the utility selected by the best-match indicator. We introduce a separate utility code for each state in which a utility operates, because state laws and state-level public utility commissions govern rate setting.

We also exploit publicly available information on the identity of those plants that purchase electricity directly from the six largest public power authorities.[15] Direct purchasers from public power authorities typically consume large quantities of electricity, and they often accept high-voltage power, operate their own transformers, and obtain electric power at heavily discounted rates. While few in number, these direct purchasers account for a large fraction of electricity purchases in some counties, and they constitute

[13] The Manufacturing Energy Consumption Survey is conducted by the EIA. The U.S. Bureau of the Census collects and compiles the data for the EIA.

[14] 460 counties are served by a single utility, 775 are served by 2 utilities, 792 are served by 3 utilities, 535 are served by 4 utilities, 440 are served by 5-7 utilities, and the remaining 29 counties are served by 8-12 utilities. To the best of our knowledge, data on the list of counties served by each electric utility are not available prior to 1999. Hence, we apply each utility's county list for 2000 to all years.

[15] They are the Tennessee Valley Authority, Bonneville Power Administration, Santee Cooper, New York Power Authority, Grand River Dam Authority, and Colorado River Commission of Nevada. Fourteen

a distinct segment of the retail electricity market. We identified between 56 and 93 direct purchasers from public power authorities per year.

It should be noted that our utility-matching procedures are imperfect, because incorrect assignments can occur in counties served by more than one utility. Matching errors between plants and utilities have no impact on much of our analysis, but they may affect our characterization of price and cost differences among utilities. In work underway, we are refining our matching procedures by drawing on utility service territory maps and zip code data for utility service areas and manufacturing plants.

Finally, we incorporated the State Energy Data 2000 files (EIA, 2003c) into the PQEM. These files include annual data on fuel sources used for electricity generation by state from 1960 to 2000. We use this data source to create annual state-level fuel shares of electricity generation for the following five categories: coal, petroleum and natural gas, hydropower, nuclear power, and other (includes geothermal, wind, wood and waste, photovoltaic, and solar).

Table 1 reports selected characteristics of the PQEM. The database contains more than 1.8 million plant-level observations over the period from 1963 to 2000. There are 3,031 counties with manufacturing plants and 349 utilities, counting multi-state utilities once for each state in which they sell to industrial customers. The table shows that electricity purchases and cost shares vary enormously across manufacturing plants. For example, the 90^{th} quantile of the purchases distribution is 381 times the 10^{th} quantile on a shipments-weighted basis and 736 times on a purchase-weighted basis. The median ratio of electricity costs to labor costs is 4.7% on a shipments-weighted basis and 17.2% on a

public power authorities supplied electricity directly to industrial customers in 2000, but the six largest accounted for nearly 98% of the revenues from direct sales to industrial customers (EIA-861 file).

purchase-weighted basis. While electricity costs are a modest percentage of labor costs for most plants, those for which electricity costs exceed 62% (201%) of labor costs account for one-fourth (one-tenth) of all electricity purchases. In other words, a large fraction of electricity is purchased by plants for which electric power is a primary or major cost of production.

4. Price Dispersion Between and Within Groups of Plants

We decompose the variance of electricity prices into within-group and between-group components using indicators for industry, geography, electricity supplier, and purchase quantity. Indexing plants by *e* and groups by *g*, write the overall variance as

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\begin{aligned}
V &= \sum_e s_e \left(p_e - \overline{p}\right)^2 = \sum_g \sum_{e \in g} s_e \left(p_e - \overline{p}\right)^2 \\
V &= \sum_g s_g \left(\sum_{e \in g} s_e \left(p_e - \overline{p}_g\right)^2 \right) + \sum_g s_g \left(\overline{p}_g - \overline{p}\right)^2 \qquad (1) \\
V &= \sum_g s_g V_g^W + V^B = V^W + V^B
\end{aligned}
$$

where p_e is the log price of electricity for plant *e*, s_e is the weight for plant *e*, $\overline{p}$ is the overall weighted mean log price, $\overline{p}_g$ is the weighted mean log price for group *g*, $s_g = \sum_{e \in g} s_e$ is the sum of weights for plants in group *g*, V_g^W is the weighted variance within group *g*, and V^B is the between-group variance. Table 2 reports the shipments-weighted version of (1) and its components for selected years, with s_e set to the product of the plant's ASM sample weight and its shipments value. Table 3 reports analogous purchase-weighted statistics.

According to Table 2, the shipments-weighted standard deviation of log electricity prices across manufacturing plants stood at 47% in 1967, fell sharply to 37%

by 1977, and then changed little over the next 23 years. Price dispersion also fell sharply on a purchase-weighted basis (Table 3), from 55% in 1967 to 43% in 1977 and then further in the 1990s to stand at 38% in 2000. Following a similar path, the between-industry dispersion of electricity prices fell rapidly through 1982 and to even lower levels in the 1990s on a purchase-weighted basis. All told, the purchase-weighted dispersion of industry prices fell by almost half over the past four decades.

Tables 2 and 3 also contain several other noteworthy results. First, spatial price differentials are large. County effects account for a high percentage of overall price dispersion, never less than 65% on a purchase-weighted basis. The 349 utilities account for more than half of overall price dispersion on a purchase-weighted basis, about 80-90 percent as much as the roughly 3,000 counties. In other words, most of the spatial price variation in the data is captured by average price differentials among utilities. It is well known that states and regions differ markedly in the mix of power sources used to generate electricity and, hence, in the cost of generation. This fact and the geography-based variance decompositions in Tables 2 and 3 lead us to consider spatial variation in power sources when we seek to explain variation in electricity costs and prices.

Second, spatial price dispersion declined sharply over time on a purchase-weighted basis, but it rose on a shipments-weighted basis. Focusing on counties, the purchase-weighted standard deviation fell by nearly one-third from 1963 to 2000, while the analogous shipments-weighted measure rose by one-fifth. We highlight this contrast in Figure 3, which displays the between-county standard deviation of log prices for both weighting methods. Figure 3 also plots the purchase-weighted between-county standard deviation for a restricted sample that excludes plants with purchases of more than 965 gigawatt-hours during the year.[16] Very few plants, ranging in number from 16-56 per year, meet this exclusion criterion. These plants account for roughly one percent of manufacturing employment and two percent of shipments, but they account for 13-23% of all electricity purchases by the manufacturing sector. The restricted-sample measure in Figure 3 shows that the entire decline in the spatial component of purchase-weighted price dispersion through the early 1980s, and most of the decline thereafter, reflects developments in the upper tail of the purchases distribution. And to a considerable extent, the discrepancy between the purchase-weighted and shipments-weighted measures of spatial price dispersion also reflects developments in the upper tail. In fact, from 1989 to 2000 the purchase-weighted spatial dispersion measure in the restricted sample is nearly identical to the shipments-weighted measure in the full sample.

Third, Tables 2 and 3 show that price differentials among customer groups defined by electricity purchase quantities also account for a high percentage of overall price dispersion, especially in the 1960s. We group plants by where they fit into the distribution of electricity purchases in the indicated year, allowing the decile and centile boundaries to vary over time. Price dispersion among purchase-level groups fell by nearly half during our sample period, with almost the entire decline concentrated between 1967 and 1977.

Fourth, purchase level and electric utility jointly account for a very high percentage of overall price dispersion throughout the past four decades. Groups defined by utility crossed with purchase deciles account for 55-74% of price dispersion on a shipments-weighted basis and 70-89% on a purchase-weighted basis. This classification

[16] We initially chose a cutoff level of 1,000 GWh but settled on 965 for data disclosure reasons.

scheme involves about 450 fewer cells than grouping by counties, but always accounts for at least as much of the price variation.

We summarize the empirical findings to this point in three statements. One, there is tremendous dispersion among manufacturing plants in price per kWh of electricity, similar in magnitude to the dispersion in hourly wages among manufacturing workers. Two, the plant-level distribution of electricity prices underwent a great compression through the late 1970s. Three, readily observed plant characteristics such as utility and purchase quantity capture most of the cross-sectional variation in electricity prices. This last finding suggests that a parsimonious empirical model focused on price differences by utility characteristics and customer purchase quantity can explain the cross-sectional price distribution and its evolution over time. We explore the role of purchase quantity more fully in the next section.

5. Electricity Price-Quantity Schedules

5.1 Cost and Demand Influences on Electricity Pricing

Supply costs per kWh of electricity tend to be lower for larger industrial and commercial customers for several reasons. Large purchasers are more likely to locate near generating facilities to minimize transmission losses. High-voltage transmission lines can lead all the way to the customer's doorstep, further reducing transmission costs. A large power user is also more likely to operate equipment at high voltage levels, circumventing or reducing the need for step-down transformers and complex distribution networks. Large power users may operate and maintain their own step-down transformers as well, relieving the utility of this task and associated costs. Larger electricity customers also have stronger incentives to respond to pricing structures that discourage volatile consumption patterns and peak-period consumption. In turn, these incentive responses economize on generating and transmission facilities and mute the effect of system-wide demand fluctuations on marginal generating costs. Similarly, larger customers have stronger incentives to consider provisions for interruptible and curtailable power as a means of lowering electricity costs. These customer supply cost characteristics provide cost-based rationales for quantity discounts in electricity pricing.

Customer demand characteristics also lead to quantity discounts under plausible conditions. Consider a utility that prices electricity to maximize consumer surplus subject to the constraint that its revenues equal its costs. As shown by Goldman et al. (1984), Brown and Sibley (1986) and Wilson (1993), among others, the optimal nonlinear pricing schedule for successive increments of electrical power satisfies the Ramsey pricing rule:

$$\frac{M(q)-C(q;Q)}{M(q)}=\frac{-\alpha}{\eta\left[M(q),q\right]} \tag{2}$$

where $M(q)$ is the marginal price for the customer's *q*th unit of electricity, $C(q;Q)$ is the marginal cost of the *q*th unit when the utility's total quantity supplied is Q, $\eta[M(q),q]$ is the elasticity of demand for the *q*th unit with respect to the marginal price, and the Ramsey number $\alpha \in [0,1]$ is chosen to satisfy the revenue constraint. Note that $\alpha = 0$ corresponds to marginal cost pricing, and $\alpha = 1$ corresponds to the standard inverse elasticity rule for a profit-maximizing multi-product monopolist.[17]

[17] It is worth pointing out that the revenue constraint does not preclude marginal cost pricing, even for a utility with declining costs over the relevant range. For example, consider a two-part tariff with a fixed access fee for each customer and marginal price set to marginal cost. Set the access fees so that total revenues cover total costs. Then, provided that the access fees are not so high as to deter participation by any consumer who values (some) electricity at more than its marginal cost, this type of two-part tariff is fully efficient (Brown and Sibley, 1986). In this case, $\alpha = 0$ and the Ramsey-pricing condition (2) reduces to a form of marginal cost pricing. When efficient pricing is infeasible, the Ramsey pricing rule (2) minimizes the allocative distortions induced by pricing above marginal cost.

According to the Ramsey pricing formula (2), the markup of price over marginal cost declines with the purchase level provided that demand becomes more price elastic for successive units. Under this condition, Ramsey pricing leads to quantity discounts even when marginal costs are invariant with respect to purchase amount. If marginal costs also decline with purchases, then Ramsey pricing implies that the marginal price schedule declines more steeply than the marginal cost schedule.

5.2 Electricity Tariffs for Industrial Customers

Electricity tariffs for industrial customers usually include separate energy and "demand" charges.[18] The energy charge depends on total kilowatt-hours of consumption during the billing period, and the demand charge depends on the highest consumption over 15- or 30-minute intervals within the billing period or longer time period. Roughly speaking, the demand charge reflects the customer's maximal requirements for power. By discouraging uneven and erratic patterns of power consumption, the separate demand charge economizes on the need for generating, transmission and transformer facilities. Eligibility for the most favorable tariff schedules is usually limited to large customers who make long term commitments to minimum contract demand levels that place a high floor on monthly charges.

Traditionally, electric utilities have offered declining-block rate schedules, whereby the marginal price per kWh of energy and the marginal price per kW of demand decline as step functions (Caywood, 1972). For bigger purchasers, in particular, electricity tariffs also depend on other factors such as voltage level and willingness to accept power interruptions or curtailments. Differential rates by time of day and other

[18] See Cowern (2001) for a concise introduction to electricity tariffs for industrial customers. Caywood (1972) provides a detailed description of electricity tariffs and rate-setting practices.

applications of peak-load pricing principles came into wider use after the mid 1970s (ELR, 1975, and Cudahy and Malko, 1976). Moves toward more finely differentiated tariff schedules for industrial customers continued through at least the late 1980s (Wilson, 1993, pages 36-38). The California Electricity Crisis of 2000-2001 intensified interest in retail pricing structures (Borenstein and Holland, 2003).

As an illustration of current and past practice, Table 4 summarizes the menu of electricity tariff schedules offered to industrial customers by Santee Cooper Power.[19] The tariffs contain three main charges: a monthly customer charge, monthly demand charges, and monthly energy charges. Larger customers face smaller energy charges per kWh and smaller demand charges per kW but higher monthly minimum charges. For example, the Medium General Service schedule offers an energy charge of 2.6¢ per kWh, a demand charge of $11.85 per kW, and a minimum monthly payment of $29. The Large Power and Light schedule offers a lower energy charge of 2.19¢ per kWh and a lower demand charge of $10.76 per kW, but a much higher minimum monthly payment of $11,960.[20] Large Santee Cooper customers who locate near transmission lines and provide their own transformers receive discounts of roughly 4% on demand charges. Optional riders to the Large Power and Light schedule offer big discounts on demand charges for off-peak power and power subject to curtailment or interruption. The Large Power and Light schedule and its optional riders require a five-year customer commitment to a contract demand level of at least 1,000 kW and the implied demand charges. These basic features

[19] Santee Cooper is also known as the South Carolina Public Service Authority. Among utilities with positive industrial revenue, Santee Cooper is close to average size with industrial sales of $238 million in 2000. The Santee Cooper schedules reflected in Table 4 are in effect as of July 2004 and date back to 1996. They are available for download at http://www.santeecooper.com/.

[20] This monthly minimum holds for a customer who contracts for at least 1,000 kW of firm power. Lower minimum charges are available to customers who accept interruptible or curtailable power.

of the Santee Cooper tariff schedules are similar to the tariff menu offered to industrial customers by Pacific Gas & Electric in 1988, as described in Wilson (1993), and to the illustrative tariff schedule for industrial customers reported by Caywood in the 1956 and 1972 editions of *Electric Utility Rate Economics.*

Recall that the PQEM contains the average price per kWh paid by a plant during the calendar year, so it does not capture the full complexity of the underlying electricity tariff schedules. In this respect, the PQEM is analogous to household and establishment-level data sets that report workers' average hourly or annual wages but not the details of the underlying compensation arrangements. To be sure, the lack of data on the underlying tariff schedules (or compensation terms) is a limitation, but it does not preclude an informative analysis. Despite the complexity of real-world compensation arrangements, there is a vast body of informative research on wage structure and labor demand that fruitfully exploits simple data on wage rates for individual workers and employers. Our empirical analysis of the retail pricing structure for electricity is in the same tradition.

5.3 Empirical Price-Quantity Schedules

We now present evidence on empirical price-quantity schedules for electricity, and changes in these schedules over time. When a plant operates for only part of the calendar year, the PQEM measure of annual kWh does not accurately indicate where the plant fits into the purchases distribution. For this reason, we henceforth exclude part-year observations.[21] We also exclude observations that display extreme seasonality or

[21] We define part-year observations as those for which the number of production workers in any single quarter is less than 5 percent of the annual average number of production workers. These part-year observations represent less than 2 percent of shipments and electricity purchases in each year.

variation in production activity within the year, because customers with highly variable loads typically face special tariff schedules with higher charges.[22]

Figure 4 shows the mean log real price of electricity by purchase decile from 1963 to 2000. The purchase deciles are almost perfectly rank ordered by price during the past four decades. Price differentials peak in 1967, when the gap in mean price between the top and bottom deciles exceeds 100 log points. Purchase-level price differentials shrink dramatically from 1967 through the first half of the 1970s, and they continue to shrink through the end of the decade. The gap between mean prices in the top and bottom deciles of the purchase distribution remains large throughout the past four decades, amounting to about 50 log points in 2000.

Figure 5 presents a more detailed empirical price-quantity schedule for selected years. It shows the fit from plant-level regressions of log price on a fifth-order polynomial in the log of annual purchases (MWh).[23] We run the regressions separately by year, weighting each observation by its shipments value and ASM sample weight. The regression fits show a dramatic flattening of the price-quantity schedule between 1967 and 1978. According to Figure 5, the price differential between the 25th and 75th centiles of the purchase distribution shrinks from 54 log points in 1967 to 25 log points in 1978, and the gap between the 5th and 95th purchase centiles shrinks from 97 to 46 log points. In short, there was a remarkably sharp erosion of quantity discounts between 1967 and the

[22] For example, Santee Cooper tariff schedule TP for temporary service (e.g., ballpark lighting) specifies a flat rate of 7.23¢ per kWh. Schedule GV for Seasonal General Service specifies energy charges of 2.34¢ per kWh and demand charges of $14.35 per kW.

[23] We also considered nonparametric regression fits for the price-quantity schedule using the SAS GAM procedure (spline option, 100 degrees of freedom). Except at the extreme upper end of the purchase distribution, accounting for less than one percent of shipments, the nonparametric fits are highly similar to the fifth-order polynomial fits. Given this similarity and the much longer run times for the nonparametric fits, especially when we add covariates, we focus on polynomial fits throughout the paper.

late 1970s. We turn next to potential explanations for these strikingly large quantity discounts and their evolution over time.

6. Behavioral Responses by Customers as a Source of Quantity Discounts

6.1 Spatial Sorting of Production Activity

If bigger purchasers locate in areas with cheaper electricity, the pooled data will show a negative relationship between price and purchase level even if all utilities offer flat price-quantity schedules. More generally, any tendency by bigger purchasers to buy from utilities with cheaper electricity contributes to a negative price-quantity relationship. This type of spatial sorting potentially explains much of the pricing structure seen in Figures 4 and 5. To evaluate this explanation, we fit two plant-level regressions of log price on a fifth-order polynomial in log purchases for each year. One regression specification includes utility fixed effects to control for the identity of the plant's electricity supplier, and the other specification omits utility effects. We then use the fitted regressions to calculate the average elasticity of electricity price with respect to customers' annual purchase levels. To isolate the role of spatial sorting, we compare the elasticity values calculated from regressions with and without utility fixed effects.

Figure 6 shows the results. It confirms a dramatic flattening of price-quantity schedules through the late 1970s, and it conveniently summarizes the magnitude of quantity discounts. In the 1960s, the average price-quantity elasticity is -22% on a purchase-weighted basis, and it ranges from -12% to -14% on a shipments-weighted basis. Bigger values for purchase-weighted elasticities reflect the steeper slopes of the price-quantity schedules at the upper end of the purchase distribution (Figure 5).

The inclusion of utility fixed effects has only a modest impact on the elasticity values prior to 1974. That is, in the early part of our sample period the huge purchase-level price differentials in Figures 4 and 5 reflect within-utility price variation, not spatial sorting of manufacturing customers. But spatial sorting clearly grows in importance after 1973, especially on a purchase-weighted basis. Evidently, the onset of rising real electricity prices in 1973 (Figure 2) encouraged the migration of electricity-intensive manufacturing activity to areas served by utilities with cheaper electricity. The bigger role for spatial sorting on a purchase-weighted basis implies that bigger purchasers are more sensitive to spatial price differences in their choice of location.

The evolution of the price-quantity elasticity also provides evidence about the impact of PURPA on a key dimension of electricity pricing. Figure 6 shows that the dramatic flattening of price-quantity schedules had already unfolded by 1978, the year of PURPA's enactment. The within-utility elasticity (i.e., controlling for utility fixed effects) fell only slightly in the first few years after 1978 on a shipments-weighted basis, and it actually rose on a purchase-weighted basis. This evidence demonstrates that the contentious rate-reform provisions in PURPA did little to restrain quantity discounts in electricity tariff schedules – at least for manufacturing customers. In this respect, PURPA merely ratified rate structure changes that had already occurred.

6.2 Other Behavioral Responses to Electricity Tariffs

In addition to location choice, several other behavioral responses by customers can influence the empirical price-quantity schedule. Bigger purchasers have greater opportunity and incentive to reduce price per kWh by managing load factors (ratio of average to peak demand), taking high-voltage power, responding to peak-load pricing structures, and accepting curtailable or interruptible power. To assess the importance of these behaviors for the observed quantity discounts, we compare the empirical price-quantity schedule in the PQEM data to the schedule for "firm" power implied by the Santee Cooper tariff summarized in Table 4. In calculating the implied price-quantity schedule for firm power, we fix the load factor at 50% and assume no discounts for off-peak or high-voltage power.[24] These assumptions serve to foreclose quantity discounts that arise from behavioral responses to pricing incentives and to thereby isolate a pure customer size effect. In contrast, the empirical price-quantity schedule reflects the pure size effect *and* the behavioral responses by electricity customers.

Figure 7 plots the implied Santee Cooper price-quantity schedule and the within-utility price-quantity schedule in the 2000 PQEM data. (We do not have enough customer observations to estimate an empirical price-quantity schedule for Santee Cooper alone.) As in Figure 5, the fitted empirical schedule is based on a fifth-order polynomial specification. We now include utility fixed effects in the plant-level regression in order to isolate within-utility price variation. Figure 7 delivers three results. First, the Santee Cooper and empirical schedules are both rather flat in the lower quartile of the purchase distribution, except at the extreme bottom end. Second, over the middle part of the distribution that roughly spans the interquartile range of purchases by manufacturing customers, the price per kWh declines with annual purchase quantity by 30 to 40 log points. Over this range, quantity discounts are essentially "built into" the tariff schedule

[24] Mechanically, we compute the lower envelope of the price-quantity schedules implied by the General Service, Medium General Service, Large General Service, and Large Power and Light schedules. Recall that the tariff schedules described in Table 4 do not include taxes or adjustments specified by the Fuel Adjustment Clause and the Demand Sales Adjustment Clause.

according to the evidence in Figure 7.[25] Third, the very large quantity discounts evident in the upper quartile of the purchase distribution are entirely driven by behavioral responses to pricing incentives. "Built in" quantity discounts do not underlie the negative price-quantity relationship in this segment of the purchase distribution. Instead, the story is one of customer responses to pricing incentives.

6.3 Summary

This section establishes that the negative price-quantity relation evident in Figures 4 and 5 reflects a combination of customer responses to pricing incentives and mechanical discounts built into electricity tariff schedules. Both aspects are important, but they are relevant for different segments of the purchase distribution. Mechanical discounts are important in the middle of the distribution, and behavioral responses to pricing incentives are important in the upper quartile. It is worth emphasizing that both the responses to pricing incentives reflected in Figure 7 and the spatial sorting response documented in Figure 6 are concentrated among larger purchasers. This evidence reinforces the view – often expressed in the public utility and Ramsey-pricing literatures – that demand is more price elastic at higher purchase levels.

7. Customer Size and Electricity Supply Costs

7.1 A Method for Estimating Supply Costs as a Function of Purchase Amount

As discussed in Section 5, customer cost and demand characteristics can both lead to quantity discounts. Figure 7 implies that cost characteristics play an important role, because discounts in the upper quartile of the purchase distribution reflect behaviors that reduce supply costs. Insofar as bigger customers have higher load factors, higher voltage

[25] The implied schedule declines more rapidly than the empirical schedule over this range, which indicates that the Santee Cooper tariff menu involves bigger "built in" quantity discounts than the average utility.

levels, closer proximity to transmission lines, their own transformers, greater response to peak-load pricing incentives, and greater willingness to accept power curtailments and interruptions, they are cheaper to supply. Of course, the negative “mechanical” relationship between price and quantity embodied in the implied Santee Cooper price schedule may also reflect lower supply costs for bigger purchasers. Thus, in line with prior views, the evidence in Section 6 implies that electricity supply costs decline with a customer’s purchase quantity.

To more precisely evaluate the role of supply costs in quantity discounts, we now describe a method for estimating the supply schedules that exploits the cross-sectional richness of the PQEM. To the best of our knowledge, our method offers a novel approach to estimating supply cost schedules as a function of customer size. The method involves three main steps. Step one uses customer-level data on purchase quantities to calculate utility-level statistics for the location and shape of the purchase distribution. Step two imposes the utility’s revenue constraint, which implies that average cost per kWh equals average price per kWh. Step three exploits cross-utility variation in the purchase distribution to estimate how costs per kWh of delivered electricity vary with customers’ annual purchases. We carry out step three using regression methods to control for other factors that affect supply costs. We now develop the method in detail.

A portion of a utility’s costs are common to all customers, and the remaining portion can be allocated to particular customers. Let θ_g be the common cost per kWh at utility *g*. Write the allocable portion of costs per kWh for customer *e* that purchases q_e as $C_g\left(q_e\right)+k_e$, where the first term captures cost differences that vary systematically by purchase level and the second term captures idiosyncratic supply cost differences unrelated to purchase level. By construction, $\sum s_e k_e = 0,$ where s_e is the share of purchases from utility *g* by plant *e*. Thus, letting *TC* denote total cost, we can write the average cost per kWh at utility *g* as

$$AC_g \equiv \frac{TC_g}{\sum_{e \in g} q_e} = \theta_g + \sum_{e \in g} s_e C_g(q_e) \tag{3}$$

The revenue constraint implies that a utility's average cost per kWh equals its average price per kWh. Imposing this constraint in (3) yields

$$P_g = \theta_g + \sum_{e \in g} s_e C_g(q_e) + v_g^P \tag{4}$$

where P_g is the purchase-weighted mean price per kWh at utility *g*, and v_g^P is an error term introduced by sampling variation in P_g. We do not directly observe the utility's average price per kWh in the PQEM, but we can estimate it using price and quantity observations on the utility's manufacturing customers.

To obtain an estimable specification from (4), we adopt three assumptions. First, we postulate that the $C_g(q)$ functions are the same for all *g* up to an additive term; i.e., $C_g(q) = C(q) + \alpha_g$. Second, we approximate $C(q)$ as a polynomial in log (*q*). Third, we model the sum of the utility's additive and common cost components as a linear function of observable utility characteristics *X*; namely, $\alpha_g + \theta_g = X_g b + u_g$ Applying these assumptions to (4) yields an estimating equation with four error components:

$$P_g = X_g b + \sum_{n=1}^{N} \gamma_n \sum_{e \in g} s_e \left[\log(q_e) \right]^n + u_g + v_g^P + v_g^q + \xi_g \tag{5}$$

where N is the order of approximation to the C function, $\sum_{e \in g} s_e \left[\log(q_e)\right]^n$ is the nth uncentered sample moment of the log purchase distribution at g, and the γ's are the key parameters of interest for the supply cost schedule. The error component v_g^q arises from sampling variation in the moments of the purchase distribution, and ξ_g arises from the polynomial approximation to C. Though not our main focus, the b parameters are also interesting, because they provide estimates of how average costs vary with utility characteristics when we control for the size distribution of customer purchases.

We estimate (5) by weighted ordinary least squares (OLS) and instrumental variables (IV) regression. We then use the γ estimates to trace out the supply cost schedule as a function of customer size. Before turning to the results, three econometric issues require some discussion.

First, consider the error term u_g in (5) that arises from unobserved determinants of the additive and common costs. If these unobserved cost determinants vary systematically with the size distribution of customer purchases, they give rise to an omitted variables problem that biases the estimates of γ. As a case in point, municipal and cooperatively owned utilities tend to serve smaller manufacturing customers.[26] If these same utilities also have lower supply costs conditional on customer size, then the regression (5) understates the extent to which costs per kWh decline with purchase amount, unless we control for utility type. Hence, we include the utility's organizational form in the X vector, distinguishing among cooperative and municipal utilities, state and federal power

[26] Davis et al. (2005) display the distribution of mean log purchases by manufacturing customers for private investor owned utilities and the analogous distribution for municipal and cooperatively owned utilities. A

authorities, and private investor-owned utilities. For similar reasons, we include controls for the size of the utility and for the shares of electrical power generated from hydro, nuclear, coal, and petroleum and natural gas. A potential omitted variables problem also arises in connection with non-sampling components of the error term v_g^P in (4) and (5). In particular, the revenue constraint might fail for manufacturing customers as a group because of cross-subsidization between classes of customers within the utility. To control for this possibility, we include in the *X* vector the fraction of the utility's revenues derived from sales to industrial customers.

Second, the error term v_g^q that arises from sampling variation in the moments of the purchase distribution create a standard errors-in-variables problem. To address this potential source of bias, we exploit the fact that consecutive ASM panels are independently drawn from the universe of manufacturing plants. It follows that the sampling error in the purchase distribution statistics for utility *g* at time *t* is uncorrelated with the sampling error at $t+k$, provided that a new ASM panel has commenced between *t* and $t+k$. Thus, we instrument the moments of the utility's log (*q*) distribution with the corresponding statistics for the same utility calculated from a nearby year that draws on a different ASM sample.[27]

Third, the number of annual customer-level observations per utility in the PQEM ranges widely from a small handful to several hundred. Hence, the sampling error components in (5) have a heteroscedastic structure. To improve the efficiency of our estimates, we weight each observation in the regression (5) by the square root of the

comparison of these distributions confirms that average customer size tends to be considerably smaller at municipal and cooperatively owned utilities.

number of manufacturing plants used to calculate the utility-level quantities. As a side benefit, this weighting method mitigates the errors-in-variable problem under OLS.

7.2 Supply Cost Estimation Results

Table 5 reports OLS regressions of the form (5) on the utility-level data. We approximate the supply cost schedule $C(q)$ as a third-order polynomial in log (q). We normalize the purchase-weighted mean price per kWh to 100 in each year, so that slope coefficients on the indicator variables can be interpreted as percentage differences from the omitted category. We report results for selected years to economize on space, but our discussion below draws on results for all years.

Table 5 shows that municipal and cooperative utilities have lower estimated supply costs in the 1960s and early 1970s, after controlling for other factors. The cost advantage of municipal and cooperative utilities over private investor-owned utilities re-emerges in the 1990s. Relative to coal-powered electricity generation, greater reliance on nuclear power yields higher supply costs; hydro power yields lower supply costs until the 1990s; and petroleum and natural gas yield higher supply costs after the 1970s. The estimated effects of power source are sizable. For example, the 1967 estimates imply that shifting 10% of power generation from coal to hydro involves a 3.3% reduction in cost per kWh. The estimates also imply that bigger utilities have lower supply costs in the 1960s, but the effects are small.

Turning to our main focus, the moments of the customer purchase distribution are jointly significant at the 0.1% level in all years. Figure 8 displays the fitted supply cost schedules as a function of customer size. Each point in the scatter plot is generated as the

[27] For k=1, we can construct instruments across ASM panels for 12 years. For k=5, we can construct instruments across ASM panels for all years. We tried both approaches.

sum of a fitted value for utility g with mean log purchases of $\overline{lq_{1g}}$,

$\tilde{P}_g = \left(\overline{X_g \hat{b}}\right) + \hat{\gamma}_1 \overline{lq_{1g}} + \hat{\gamma}_2 \left(\overline{lq_{1g}}\right)^2 + \hat{\gamma}_3 \left(\overline{lq_{1g}}\right)^3$, plus the regression residual for the utility. As seen in Figure 8 and Table 6, supply costs per kWh fall by a factor of 2 or 3 over the range of purchases spanned by the utilities in our sample. This pattern holds for every year of our sample. In unreported results, we re-estimated the supply cost regressions by IV using the approach described above, and obtained highly similar results. These results provide convincing evidence of powerful, cost-based reasons for large quantity discounts in electricity pricing.

We also computed the average elasticity of supply costs with respect to customer size for each year and compared it to the average elasticity of price with respect to customer size (Figure 6). This comparison yields two results. First, the average cost elasticity is consistently larger in magnitude than the average price elasticity. Second, the longer term swings in the average price elasticity are closely mirrored by swings in the average cost elasticity. These comparisons reinforce the evidence in Figure 8 and Table 6 that cost factors are a major source of quantity discounts in electricity pricing.

8. Evaluating the Pricing Structure *(This section is preliminary)*

8.1 Is Pricing Efficient?

Economic efficiency requires that the marginal prices for successive increments of electrical power equal the marginal supply costs at all points along the customer purchase distribution. This is a demanding requirement in our context, because the range of customer purchases is enormous. To evaluate this requirement, we calculate the marginal cost and marginal price schedules implied by our estimated supply cost and price-quantity schedules. For example, let $T(q) = qP(q)$ be the total electricity tariff paid by a plant that purchases q kWh, where $P(q)$ is the average price per kWh. We compute the marginal price schedule, $M(q) = P(q) + qP'(q)$, using

$$\hat{M}(q) = \hat{P}(q) + (q/\varepsilon)\left[\hat{P}\left(q + (\varepsilon/2)\right) - \hat{P}\left(q - (\varepsilon/2)\right)\right] \quad (6)$$

where $\hat{P}(q)$ is the fitted value of the price-quantity schedule at q, and ε is a small positive number. We follow the same approach in calculating marginal cost schedules from supply cost schedules of the type displayed in Figure 8.

For purposes of comparing the marginal curves, we re-estimated the price-quantity schedules by regressing price per unit (not logged) on a third-order polynomial in the log of customer purchases. We also omitted plants with annual purchases outside the range of mean log purchases in the utility-level data. These modifications to the specification and sample used in Sections 5 and 6 provide for an apples-to-apples comparison of the marginal curves. We include utility fixed effects in the plant-level regressions to isolate within-utility price variation.[28]

Figure 9 shows that the marginal price and marginal cost curves are remarkably similar in 1967 and 1973, confirming a basic implication of pricing efficiency. The same pattern holds in 1972. After 1973, a gap begins to open between marginal cost and marginal price in the lower half of the purchases distribution. By 1978, the gap is large, and it remains so through 2000. In the upper half of the distribution, the data conform to pricing efficiency throughout the period from 1967 to 2000.

Figure 10 summarizes the average difference between marginal price and marginal cost in upper and lower segments of the purchases distribution. In the upper half

[28] It should be noted that our evaluation of pricing efficiency is not designed to assess whether each utility has an efficient pricing structure for its industrial customers. Rather, we seek to evaluate the extent to which pricing efficiency holds or fails on average for utilities that serve U.S. industrial customers.

of the distribution, the difference between marginal price and marginal cost is minimal from 1967 to 2000, confirming the impression from Figure 8. In the third and fourth deciles, the average marginal price is 10-20% below the average marginal cost after 1980.[29] This is a large and persistent departure form marginal cost pricing. It is especially puzzling in light of the successful implementation of marginal cost pricing prior to the mid 1970s.

What caused the departure from pricing efficiency after the early 1970s? An answer to that question is beyond the scope of this paper, but we can suggest avenues for future investigation. First, sizable deviations from marginal cost pricing began to emerge at the same time as real electricity prices began to rise (Figure 2). As discussed in Section 2, the rise in real electricity prices from 1973 to 1983 reversed a decades-long trend. Perhaps utility companies or their regulators deliberately sought to insulate smaller industrial customers from the full impact of rising energy costs. A difficulty with this story is its failure to explain the persistence of deviations from marginal cost pricing even when real electricity prices resumed a downward trend after 1983.

Second, during the 1970s public utility commissions began to focus greater effort on the review and design of electricity tariff schedules, as discussed by Cudahy and Malko (1976) in their treatment of the landmark Madison Gas and Electric case. The Madion case, initiated in 1972, stimulated similar reviews in other states. “By 1977, 12 state commissions had held generic hearings on retail electric rate structure reform.” (Joskow, 1979, age 794). Ironically, these moves toward more aggressive intervention in rate design were often presented as an effort to implement marginal-cost pricing

[29] The utility-level data contain few observations with mean log purchases in the first and second deciles of the purchases distribution, so we focus on the third and fourth deciles.

principles. Our evidence shows that greater involvement in the review and design of rate structures by public utility commissions coincided with significant steps away from efficient pricing on the margin we measure. A careful study of whether intervention by public utility commissions caused the departures from efficient pricing seen in Figures 9 and 10 is a worthy topic for future investigation.

8.1 Is There Any Role for Ramsey Pricing?

Figures 9 and 10 also show that the data provide no support for the standard Ramsey-pricing explanation of quantity discounts. According to this explanation, the markup of marginal price over marginal cost is positive, and it declines with the elasticity of demand. By all accounts, and consistent with our evidence in Section 6, demand is more price sensitive in the upper segments of the purchases distribution. Hence, the standard Ramsey-pricing perspective predicts that marginal price exceeds marginal cost, and that the markup shrinks with purchase level. The pattern in Figures 9 and 10 is more nearly the opposite.

That the data do not conform perfectly to Ramsey pricing is no surprise. However, we are struck by the utter failure of the standard Ramsey-pricing view to account for *any* portion of the large quantity discounts in electricity pricing. Evidently, cost differences and not markup differences are the predominant reason for quantity discounts. When the pricing structure deviates from efficiency, it does so in the opposite direction from the prediction of the standard Ramsey-pricing view.

It is worth remarking, however, that the data might be reconciled with Ramsey pricing under the unusual premise that marginal cost pricing raises too *much* revenue; i.e., that efficient pricing raises more revenue than required to cover costs and a normal return on equity. In this circumstance, Ramsey-pricing logic implies that the second-best pricing structure involves bigger *markdowns* of marginal prices relative to marginal costs in the less elastic portion of the purchases distribution. That is essentially the marginal pricing structure that emerges after 1973. The premise that yields this rationalization is greatly at odds with the traditional view that electric utilities operate with declining costs. However, it resonates with evidence that changes in the regulatory environment over the course of the 1970s led to tighter capacity constraints and higher costs of expanding capacity. In any event, the role of tighter constraints on capacity in the move away from efficient pricing is another worthy topic for future investigation.

9. Concluding Remarks

We summarize our main empirical results:

1. There is tremendous dispersion among manufacturers in the prices they pay per kWh of electricity. Looking across manufacturing plants, the purchase-weighted standard deviation of log electricity prices exceeds 40% in recent decades.
2. The distribution of log electricity prices underwent a great compression between 1967 and the late 1970s because of a dramatic flattening of price-quantity schedules. The average elasticity of price per kWh with respect to annual purchase quantity shrank from -22% to -9% during this period.
3. Supply costs per kWh decline by more than half over the range of customer purchases in the cross section. This finding provides clear evidence of a powerful cost-based rationale for large quantity discounts in electricity pricing.
4. Among smaller and mid-sized manufacturing customers, quantity discounts are built into electricity tariff schedules in a mechanical way. Among customers in the upper

quartile of the purchases distribution, even deeper quantity discounts arise from behavioral responses to pricing incentives.

5. Until the mid 1970s, marginal costs and marginal prices with respect to customer purchase quantities are nearly identical, remarkably in line with efficient pricing. After 1973, a gap begins to open between marginal prices and marginal costs in the lower half of the purchases distribution. From 1981 onwards, the marginal cost of incremental electricity purchases exceeds the marginal price by 10-20% for smaller manufacturing customers.
6. The data provide no support for the Ramsey-pricing view that quantity discounts reflect smaller markups over marginal cost for more price-sensitive customers.
7. Except at the top end of the purchases distribution, the spatial component of price dispersion displays no downward trend until the 1980s. Even then, spatial convergence in retail electricity prices for manufacturing customers is quite limited.
8. The spatial sorting of electricity-intensive manufacturing activity to areas with cheaper electricity is modest, but it increases after 1973, apparently in response to a shift from falling to rising real electricity prices.

These findings considerably expand our knowledge of electricity pricing to industrial customers in the United States, particularly in connection with the magnitude and sources of quantity discounts. They strengthen the empirical basis for theorizing about public utility pricing, for evaluating the impact of regulatory expansion in the 1970s, and for assessing the effects of wholesale power markets on spatial price dispersion at the retail level. They also point to several questions for future research: Why has the rapid expansion of wholesale power markets in the 1990s had such a limited effect on spatial price dispersion at the retail level (Figure 3)? Why did the price-quantity schedule flatten so sharply between 1967 and 1977 (Figures 5 and 6)? Why did electricity pricing to manufacturing customers deviate from an efficient structure after 1973, and why are the deviations limited to the lower half of the purchases distribution (Figures 9 and 10)? How big are the costs of these departures from pricing efficiency? All of these questions can be fruitfully attacked with the help of the PQEM database developed in the course of preparing this study.

Dispersion in electricity prices and other inputs also has important implications for the study and interpretation of productivity differences. As Bartelsman and Doms (2000) conclude in their review of empirical work on the topic, productivity dispersion in the cross section is “extremely large”. Lacking data on input prices, productivity studies typically rely on input expenditures in place of input quantities. Obviously, this procedure yields measured differences in productivity even when physical productivities are identical. In this regard, we stress that Tables 2 and 3 report large differences in electricity prices within narrowly defined manufacturing industries. Casual empiricism suggests that quantity discounts of various forms are prevalent for many intermediate inputs including office supplies, computer software, legal services, information goods, and airline travel. More systematic evidence supports this impression. In a field study of 39 manufacturing and service firms, Munson and Rosenblatt (1998) find that 83% receive quantity discounts for *most* of the items they purchase. If larger businesses are better positioned to exploit quantity discounts, then most previous studies overstate the relative physical productivity of bigger producers. These observations suggest that input price variation among producers merits greater attention in future research on productivity differences.

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Table 1. Selected Characteristics of the PQEM Database

Years covered	1963, 1967, 1972-2000								
Number of plant-level observations per year	48,164 to 72,128								
Total number of annual plant-level observations[a]	1,816,720								
Number of counties with manufacturing plants	3,031								
Number of 4-digit SIC industries (1972 / 1987)[b]	447 / 458								
Number of best-match utilities[c]	349								
Mean annual electricity purchases, Gigawatt hours (GWh)[d]	99.7 (860.4)								
Standard deviation of annual electricity purchases (GWh)[d]	334.0 (2,400.0)								
	Quantiles of Annual Electricity Purchases, Gigawatt-hours								
Weighting Method	1	5	10	25	50	75	90	95	99
Shipments	.07	.30	.70	3.22	16.4	89.1	267	443	997
Purchases	.20	1.08	2.84	13.58	85.9	452	2,091	4,089	14,000
Weighting Method	Quantiles of Electricity Costs as a Percent of Total Labor Costs								
Shipments	0.4	1.1	1.5	2.6	4.7	10.2	25.6	46.2	102.6
Purchases	1.1	2.1	2.9	6.1	17.2	61.7	200.9	305.6	847.7

Notes:
[a] The initial sample contains 1,945,813 records. We drop 107 records because of invalid geography codes and 128,058 (6.6%) because of missing values for electricity price, total employment, value added or shipments. We also trim the bottom 0.05% of the electricity price distribution in each year (928 observations over all years).
[b] We use 1972 SIC codes in 1963, 1967, and 1972-1986 and 1987 SIC codes in 1987-2000. See Davis et al. (2004) for additional information.
[c] There are 336 best-match utilities not counting public power authorities: Tennessee Valley Authority, Bonneville Power Administration, New York Power Authority, Santee Cooper, Grand River Dam Authority, and the Colorado River Commission of Nevada. By construction, a best-match utility does not cross state lines.
[d] Weighted by shipments (electricity purchases).

Table 2. The Shipments-Weighted Distribution of Log Electricity Prices Paid by U.S. Manufacturing Plants, Dispersion and Variance Decompositions

	1963	1967	1972	1977	1982	1987	1992	1997	2000
Overall Standard Deviation	.409	.468	.429	.369	.359	.347	.373	.388	.360
Price Dispersion Between Industries									
4-Digit SIC Industries (447/458)⁺									
Between Variance as % of Total	36.6	36.3	28.0	20.6	19.4	23.1	26.4	25.1	23.8
Between Standard Deviation	.248	.282	.227	.167	.158	.167	.192	.194	.175
Price Dispersion Between Geographic Areas									
NERC Regions (12)									
Between Variance as % of Total	9.0	9.7	12.6	13.2	17.8	14.9	22.1	20.8	21.1
Between Standard Deviation	.123	.146	.152	.134	.152	.134	.175	.177	.165
States (51)									
Between Variance as % of Total	11.9	13.6	17.3	34.8	46.5	36.7	42.7	39.4	38.0
Between Standard Deviation	.141	.173	.179	.218	.245	.210	.243	.244	.222
Utilities (349)									
Between Variance as % of Total	19.7	21.3	22.6	42.2	56.0	44.3	50.2	46.9	44.9
Between Standard Deviation	.182	.216	.204	.240	.269	.231	.264	.266	.241
Counties (3,031)									
Between Variance as % of Total	31.4	32.0	32.2	53.0	67.2	54.3	61.6	57.6	56.3
Between Standard Deviation	.230	.265	.244	.269	.294	.256	.292	.295	.270
Price Dispersion Between Groups Defined by Annual Electricity Purchases									
Purchase Deciles (10)									
Between Variance as % of Total	57.2	54.2	33.2	16.4	19.3	26.2	29.0	30.6	25.6
Between Standard Deviation	.310	.345	.247	.150	.158	.177	.201	.215	.182
Purchase Centiles (100)									
Between Variance as % of Total	61.1	57.2	35.8	18.6	21.6	28.7	31.9	32.7	29.0
Between Standard Deviation	.320	.354	.257	.159	.167	.186	.210	.222	.194
Price Dispersion Between Groups Defined by Utility and Purchase Level									
Utility x Purchase Decile (2,583)									
Between Variance as % of Total	73.9	69.6	55.3	59.0	71.8	65.4	72.3	70.2	68.1
Between Standard Deviation	.352	.391	.319	.283	.304	.281	.317	.325	.297
Utility x Purchase Centile (21,607)									
Between Variance as % of Total	83.3	78.7	66.4	69.7	81.1	76.6	82.6	81.5	80.0
Between Standard Deviation	.373	.416	.350	.308	.323	.304	.339	.351	.322

⁺ Years prior to 1987 are classified using the 1977 SIC system (447 4-digit industries). Years 1987 and later are classified using the 1987 SIC system (458 4-digit industries).

Source: Authors’ calculations on PQEM data.

Table 3. The Purchases-Weighted Distribution of Log Electricity Prices Paid by U.S. Manufacturing Plants, Dispersion and Variance Decompositions

	1963	**1967**	**1972**	**1977**	**1982**	**1987**	**1992**	**1997**	**2000**
Overall Standard Deviation	.524	.552	.478	.433	.439	.429	.477	.437	.383
Price Dispersion Between Industries									
4-Digit SIC Industries (447/458)+									
Between Variance as % of Total	71.3	61.4	48.8	40.9	37.9	46.8	59.0	44.5	37.5
Between Standard Deviation	.443	.432	.334	.277	.270	.293	.366	.292	.234
Price Dispersion Between Geographic Areas									
NERC Regions (12)									
Between Variance as % of Total	22.1	18.9	19.5	9.2	10.2	8.4	10.3	9.8	13.5
Between Standard Deviation	.246	.240	.211	.131	.140	.124	.153	.137	.141
States (51)									
Between Variance as % of Total	43.8	40.5	37.5	40.0	45.7	38.3	39.3	37.5	39.5
Between Standard Deviation	.347	.351	.293	.274	.297	.265	.299	.268	.240
Utilities (349)									
Between Variance as % of Total	65.0	56.2	49.7	56.0	62.0	55.2	57.0	52.9	50.8
Between Standard Deviation	.423	.414	.337	.324	.345	.318	.360	.318	.273
Counties (3,031)									
Between Variance as % of Total	77.9	69.6	64.9	73.5	78.6	74.9	77.5	69.9	65.4
Between Standard Deviation	.462	.460	.385	.371	.389	.371	.419	.365	.310
Price Dispersion Between Groups Defined by Annual Electricity Purchases									
Purchase Deciles (10)									
Between Variance as % of Total	62.8	56.3	36.2	27.4	24.7	38.0	49.5	41.3	38.1
Between Standard Deviation	.415	.414	.288	.227	.218	.264	.335	.281	.236
Purchase Centiles (100)									
Between Variance as % of Total	74.7	65.5	41.5	33.8	31.8	45.0	60.8	45.9	43.4
Between Standard Deviation	.453	.446	.308	.252	.247	.288	.372	.296	.252
Price Dispersion Between Groups Defined by Utility and Purchase Level									
Utility x Purchase Decile (2,583)									
Between Variance as % of Total	89.2	82.3	69.7	73.2	78.3	76.0	80.8	75.5	72.9
Between Standard Deviation	.495	.501	.399	.370	.388	.374	.428	.380	.327
Utility x Purchase Centile (21,607)									
Between Variance as % of Total	94.1	90.4	80.5	83.1	87.8	87.5	90.4	86.5	84.7
Between Standard Deviation	.508	.524	.429	.395	.411	.401	.453	.407	.352

+ Years prior to 1987 are classified using the 1977 SIC system (447 4-digit industries). Years 1987 and later are classified using the 1987 SIC system (458 4-digit industries).

Source: Authors' calculations on PQEM data.

Table 4. Menu of Electricity Tariff Schedules Offered to Industrial Customers by Santee Cooper Power as of July 2004

Service Type and Schedule	Energy Charge Per kWh	Monthly Demand Charge Per kW	Minimum Monthly Demand Charge	Own Trans-Former Discount?	Monthly Customer Charge	Customer Profile
General Service, GN-96	6.56¢	None	None	No	$6.85	Less than 90 MWh per year
Medium General Service, GS-96	2.60¢	$11.85	$11.85	No	$16.15	Greater than 90 MWh and less than 1,080 MWh per year
Large General Service, GL-96 (Optional provision for interruptible power)	2.32¢	$13.20 ($8.57 for interruptible portion)	$3,960	Yes, $0.50 per kW	$24.00	Greater than 1,080 MWh per year, and delivery points near transmission line
General Service Time of Use, GT-96	2.32¢	$13.20 peak, $3.87 off-peak		No	$24.00	Greater than 90 MWh per year
Large Power and Light, L-96 (Requires 5-year contract with high floor on demand charges)	2.19¢	$10.76 (extra $6.00 per kW in excess of contract level)	$10,760 (for 1,000 kW of Firm Power)	Yes, $0.50 per kW	$1,200	Demand greater than 1,000 kW and delivery points near transmission lines; minimum 5-year commitment.

Optional Riders to Large Power and Light Schedule

Curtailable Supplemental Power, L-97	Different energy charges and a discount of 72% on demand charges for supplemental power that is subject to temporary or permanent curtailment or interruption with six months notice.
Interruptible Power, L-02-I	Discount of 36% on demand charges for power subject to curtailment or interruption on short notice (2.5 hours); limitations on frequency and duration of curtailments and interruptions; one-year advance notice required by customer to reduce interruptible portion of demand.
Off-Peak Service, L-96-OP	Discount of 80% on demand charges for off-peak power in excess of contracted levels for Firm, Supplemental and Interruptible Demands; subject to curtailment or interruption on short notice.
Economy Power, L-02-EP	Discounted energy charges offered, at Santee Cooper's sole discretion, to customers with Contract Demand greater than 2,000 kW. Available on short notice during specified clock hours.
Standby Power, L-96-SB	Available at Santee Cooper's discretion to customers with alternative non-emergency power sources.

Notes:

1. The charges listed above exclude South Carolina Sales Tax and other taxes and fees levied by governmental authorities.
2. Electricity is metered and billed separately for each delivery point and voltage level, so that the Monthly Customer Charge and Minimum Monthly Demand Charge apply per delivery point and voltage level.
3. All service types are subject to a Fuel Adjustment Clause (FAC-96) whereby the energy charge per kWh is adjusted by an additive factor that depends on Santee Cooper's fuel costs in the preceding three months, an allowance for its capital improvements and distribution losses, and other considerations. The energy charge adjustment per kWh is similar for all service types, but the adjustment is less sensitive to capital improvements and distribution losses under the Large Power and Light schedule. Under all schedules, standard "firm-requirements" service is also subject to a Demand Sales Adjustment Clause (DSC-96) that credits Santee Cooper customers with specified shares of its demand-related and capacity-related revenues. The Demand Sales Adjustment can be positive or negative. It is applied as a proportional adjustment to the monthly demand charge under the Large Power and Light schedule and as a proportional adjustment to the monthly energy charge under the General Service schedules.
4. The kW level used to calculate the Monthly Demand Charge can be greater than "Measured Demand" during the billing period, defined as "the maximum 30-minute integrated kW demand recorded by suitable measuring device during each billing period." For example, the Medium General Service schedule states that the "monthly Billing Demand shall be the greater of (i) the Measured Demand for the current billing period or (ii) fifty percent (50%) of the greatest Firm Billing Demand computed for the preceding eleven months." The Large General Service schedule specifies a 70% figure.
5. The discounted Demand Charge under the General Service Time-of-Use Schedule applies to the difference between the customer's Off-Peak Measured Demand and the customer's On-Peak Measured Demand.
6. The transformer discount requires that the customer take delivery at available transmission voltage (69kV or greater).
7. Customers that opt for curtailable or interruptible power forfeit all discounts previously received during the calendar year for such power in the event they fail to meet a request for power curtailment or interruption. In addition, future discounts for curtailable and interruptible power can be withdrawn.
8. Under the Large Power and Light schedule, the customer must commit to a Firm Contract Demand level for a five-year period. The Firm Contract Level places a floor on the demand level used to compute the Monthly Demand Charge. Lower minimum monthly demand charges are available under certain conditions. The Large Light and Power Schedule also includes an Excess Demand Charge of $6.00 per kW for Measured Demand in excess of the Firm Contract Demand, a charge of $0.44 per kVAr of Excess Reactive Demand, and a Monthly Facilities Charge equal to 1.4% of the original installed cost of any facilities that Santee Cooper provides in addition to the facilities it normally provides to its customers.

Source: Santee Cooper tariff schedules for commercial and industrial customers at http://www.santeecooper.com/ (20 July 2004).

Table 5. Regression Results for Electricity Supply Costs, Selected Years

Dependent Variable: Purchase-weighted mean price per kWh for the utility's manufacturing customers

	1967	**1973**	**1978**	**2000**
Public Ownership	36**	24**	15	19
	(9)	(9)	(14)	(13)
Private Ownership	41**	23**	14**	11*
	(4)	(3)	(4)	(4)
Fraction of Utility Total Revenue from Industrial Customers	0	-28**	-35**	-7
	(9)	(10)	(12)	(11)
Share of Power From Hydro	-33**	-45**	-55**	15
	(5)	(5)	(6)	(8)
Share of Power From Nuclear	377**	49**	13	47**
	(83)	(13)	(7)	(9)
Share of Power From Oil and Natural Gas	-4	-5	8	42**
	(3)	(4)	(6)	(8)
Adjusted R-Square	0.80	0.70	0.64	0.66
Test: Utility Size Measures = 0	0.00	0.82	0.45	0.61
Test: Customer Size Measures = 0	0.00	0.00	0.00	0.00
Test: Ownership Measures = 0	0.00	0.00	0.00	0.03
N	222	230	238	227

* p<0.05, ** p<0.01

Notes:

1. Regressions are on utility-level data by weighted least squares. Weights are proportional to the square root of the number of customer observations used to calculate the utility-level statistics. The sample is limited to utilities for which there are at least 8 customer-level observations. The dependent variable is normalized so that the purchase-weighted mean price over utilities equals 100.
2. In addition to the variables shown in the table, the regression also includes the first three uncentered moments of the utility's log customer size distribution and a quadratic polynomial in the log of the utility's electricity sales to industrial customers.
3. The ownership variables and the fraction of total revenue from industrial customers are from the 2000 EIA-861 file. Public and private ownership variables are dummy variables, and the omitted category is cooperative and municipal ownership. Fuel share variables are state-level data from the State Energy Data 2000 files. Both coal and "other" (includes geothermal, wind, wood and waste, photovoltaic, and solar) are omitted since "other" is always very small. Moments of the customer size distribution are constructed from the PQEM.

Source: Authors' calculations on data from the PQEM, EIA-861 files, and State Energy Data 2000.

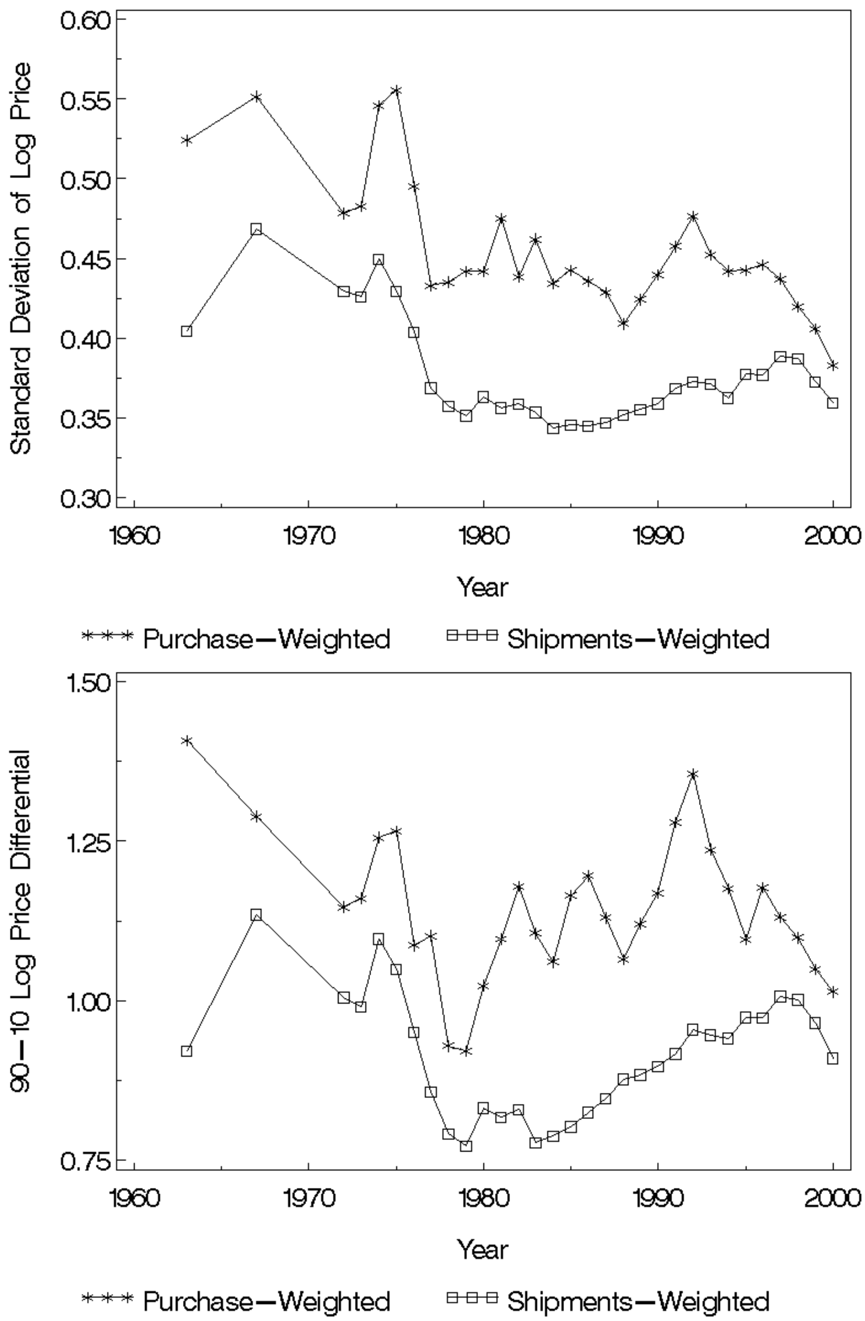
Table 6. Estimated Electricity Supply-Cost Schedules as a Function of Customer Purchase Quantity, Selected Years

Annual Purchase Amount in Gigawatt hours	Percentile of Purchases Distribution	Supply Costs per kWh in 1996 Cents			
		1967	1973	1978	2000
0.54	10	8.24	6.51	10.0	10.6
2.43	25	5.77	4.89	7.57	7.54
13.1	50	4.21	3.80	6.05	5.43
73.9	75	3.41	3.20	5.33	4.30
229	90	3.08	2.96	5.07	3.92
422	95	2.89	2.85	4.95	3.78
1,130	99	2.51	2.65	4.69	3.60

Notes:

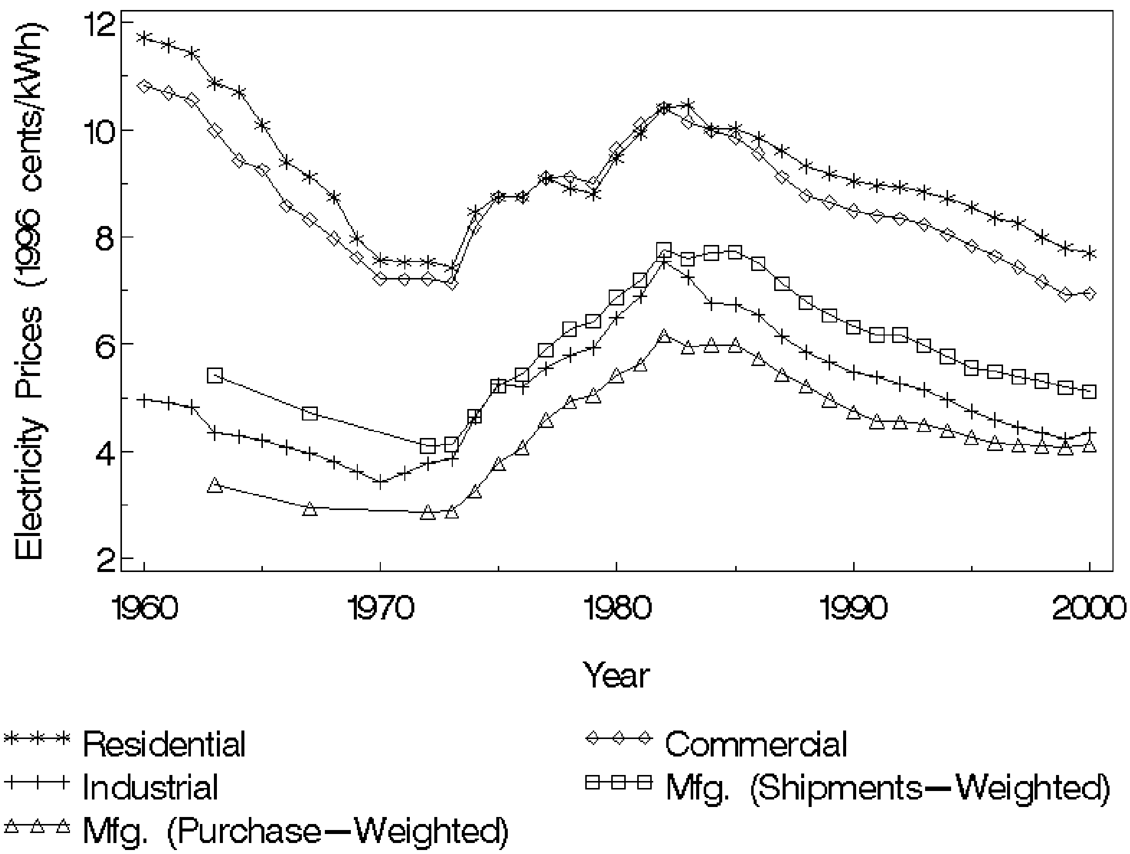
1. The supply-cost schedules are derived from the regressions reported in Table 5 and described in Section 7.1. The schedules are evaluated at sample mean values of the other regression covariates.
2. The percentiles of the purchases distribution are the simple average of the percentiles of the shipments-weighted purchase distribution in 1967, 1973, 1978, and 2000.
3. We do not report supply costs for the bottom tail of the purchases distribution, because small purchase values are outside the range we used to fit the utility-level regressions in Table 5.

Source: Authors’ calculations on PQEM data.



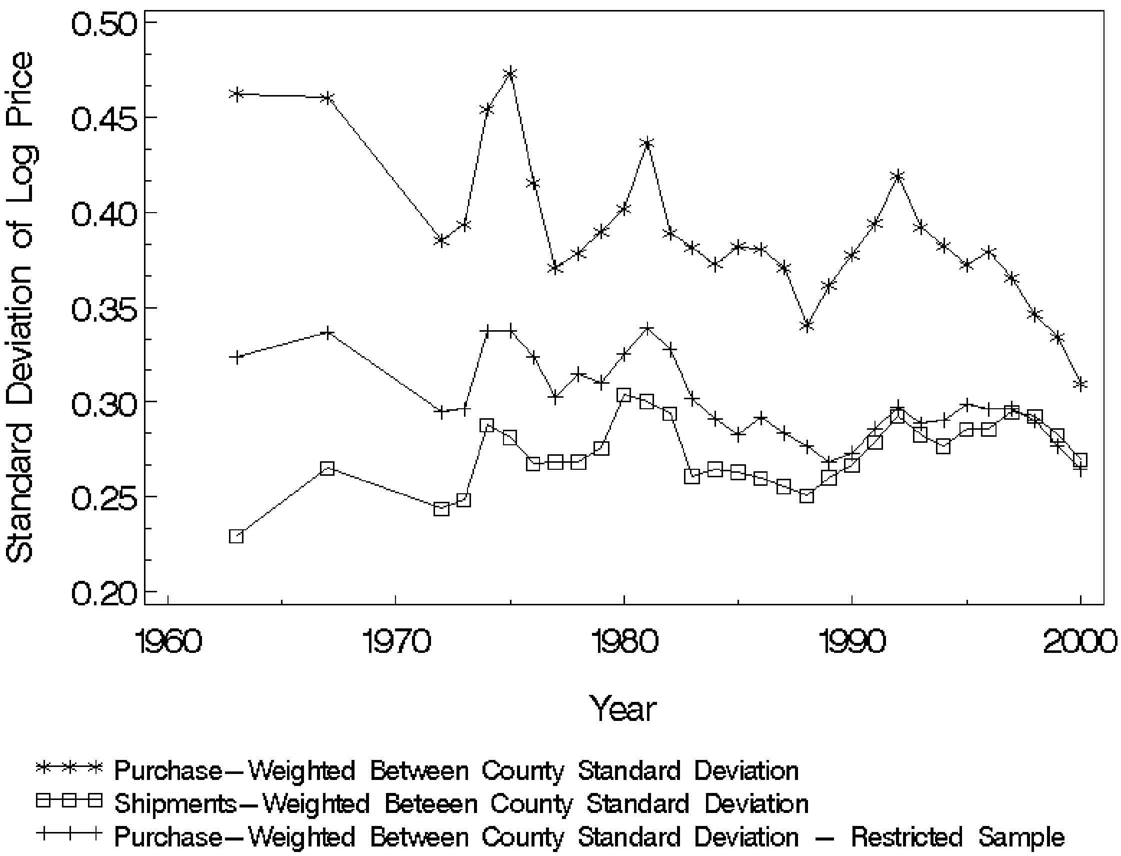
Source: Authors' calculations on PQEM data.

Figure 1. Electricity Price Dispersion Among U.S. Manufacturing Plants, 1963-2000



Source: Energy Information Administration for Residential, Commercial and Industrial series; authors' calculations on PQEM data for Manufacturing.

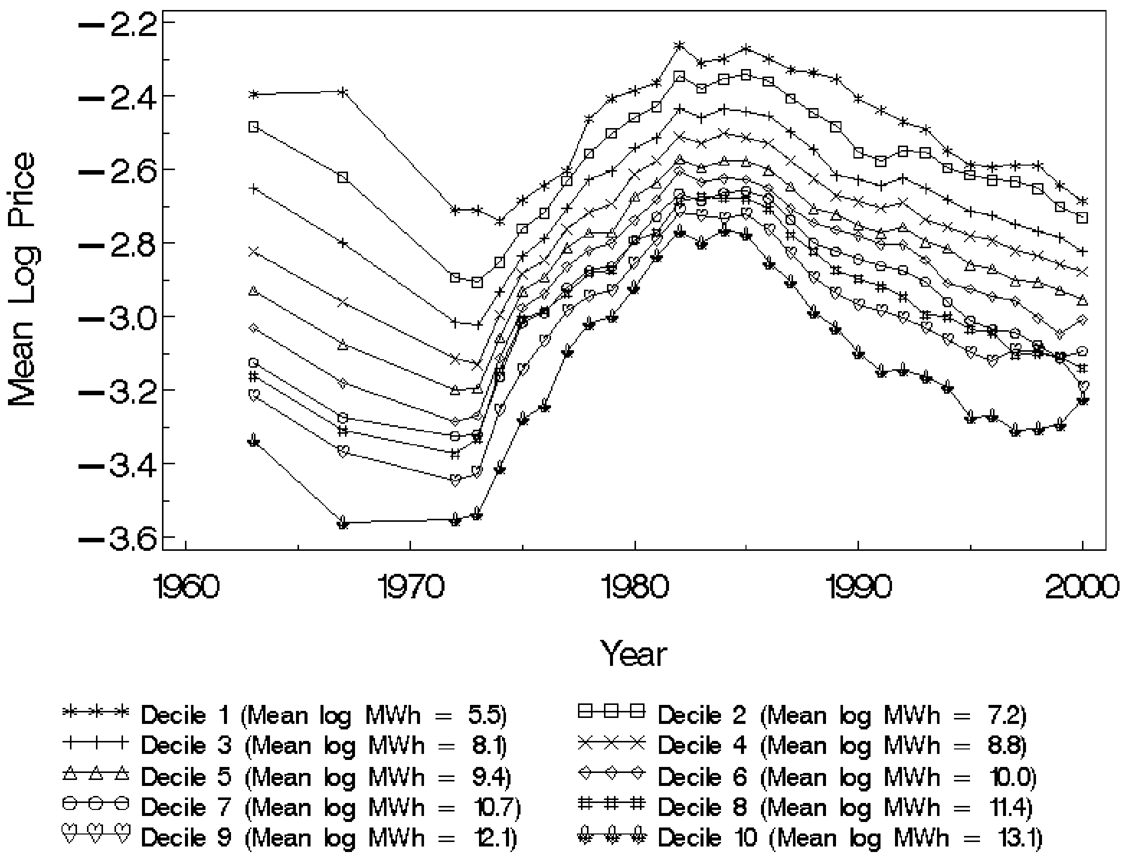
Figure 2. Real Electricity Prices by End-Use Sector, 1960-2000



Source: Authors' calculations on PQEM data.

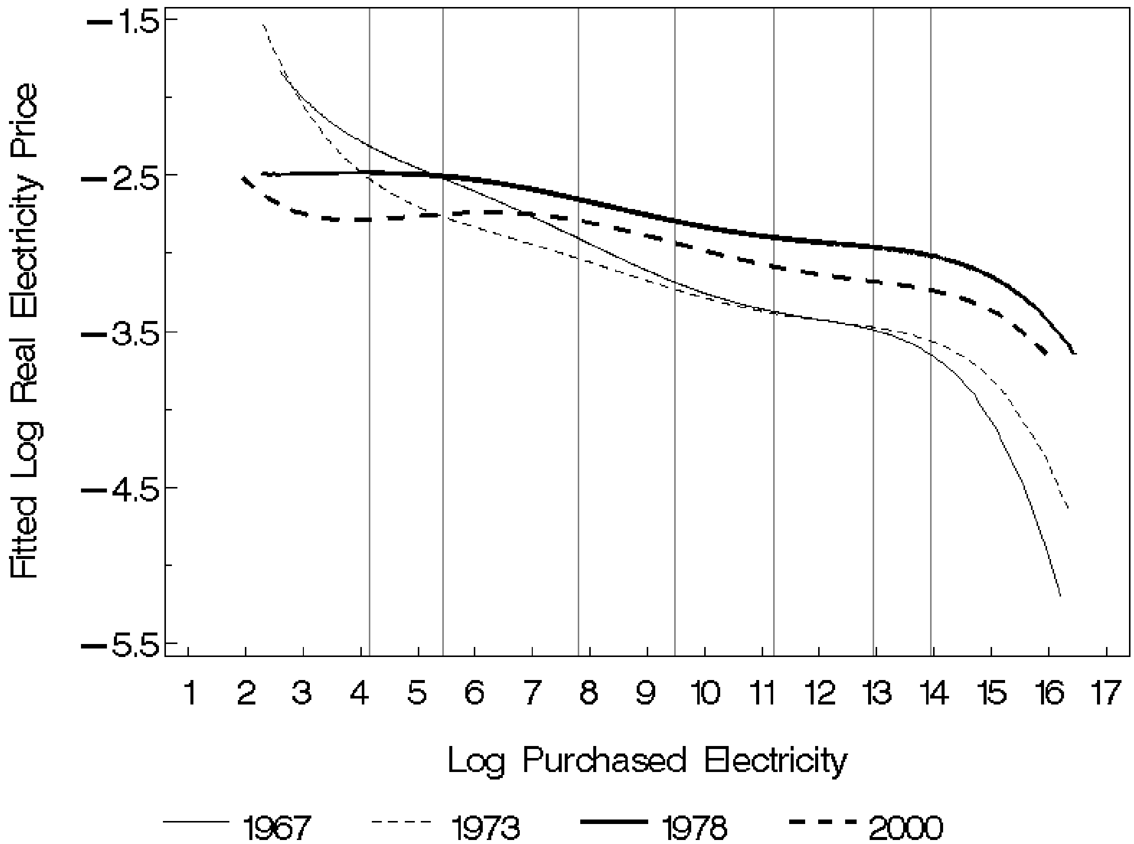
Note: The restricted sample excludes plants that purchase more than 965 gigawatt-hours of electricity during the year. There are 16-56 plants per year that meet this condition.

Figure 3. Spatial Dispersion in Electricity Prices, 1963-2000



Source: Authors' calculations on shipments-weighted PQEM data with part-year observations excluded.

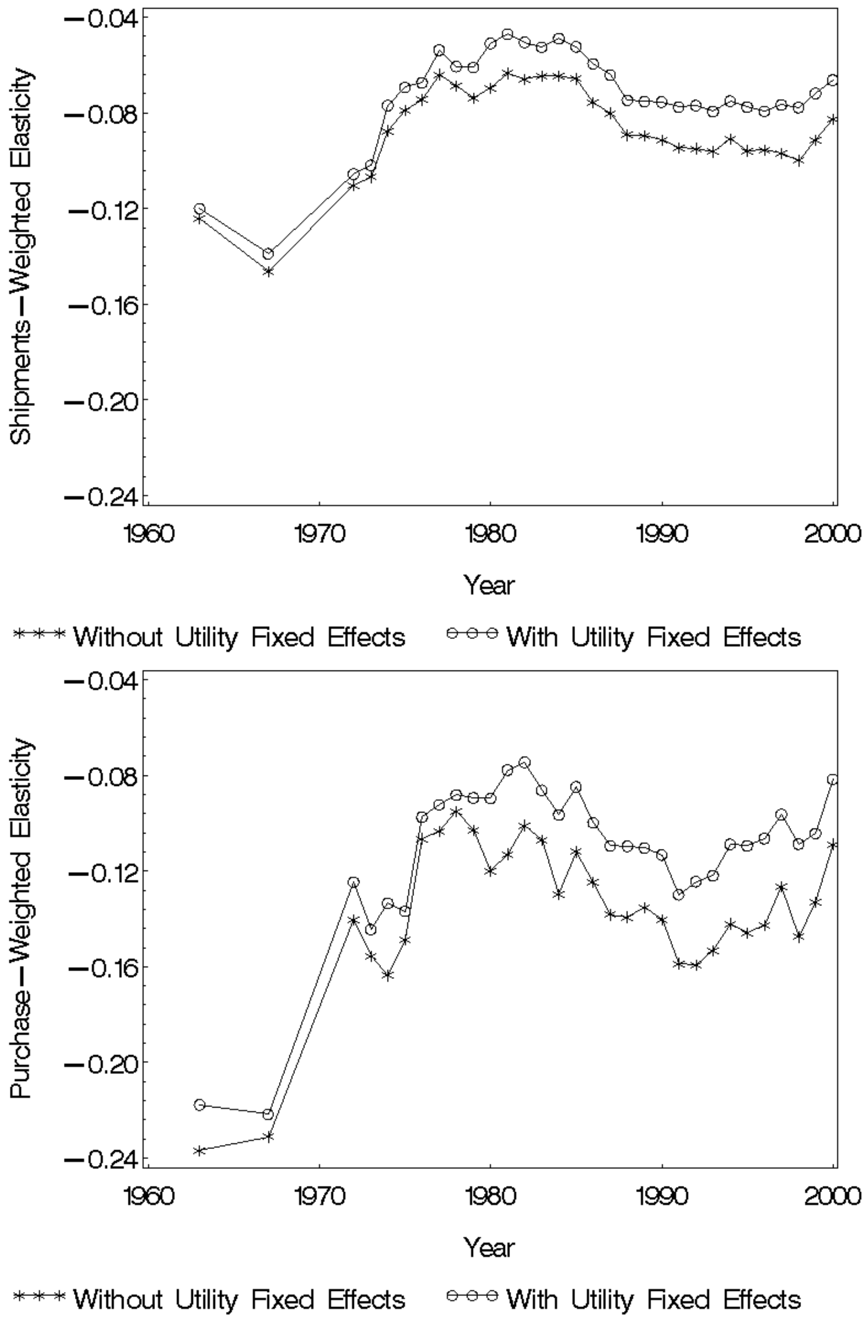
Figure 4. Mean of Log Real Electricity Prices by Purchase Deciles, 1963-2000



Source: Authors' calculations on PQEM data with part-year observations excluded.

Note: Vertical lines depict the simple average of the 1st, 5th, 25th, 50th, 75th, 95th and 99th percentiles of the shipments-weighted distribution of annual purchases for 1967, 1973, 1978, and 2000.

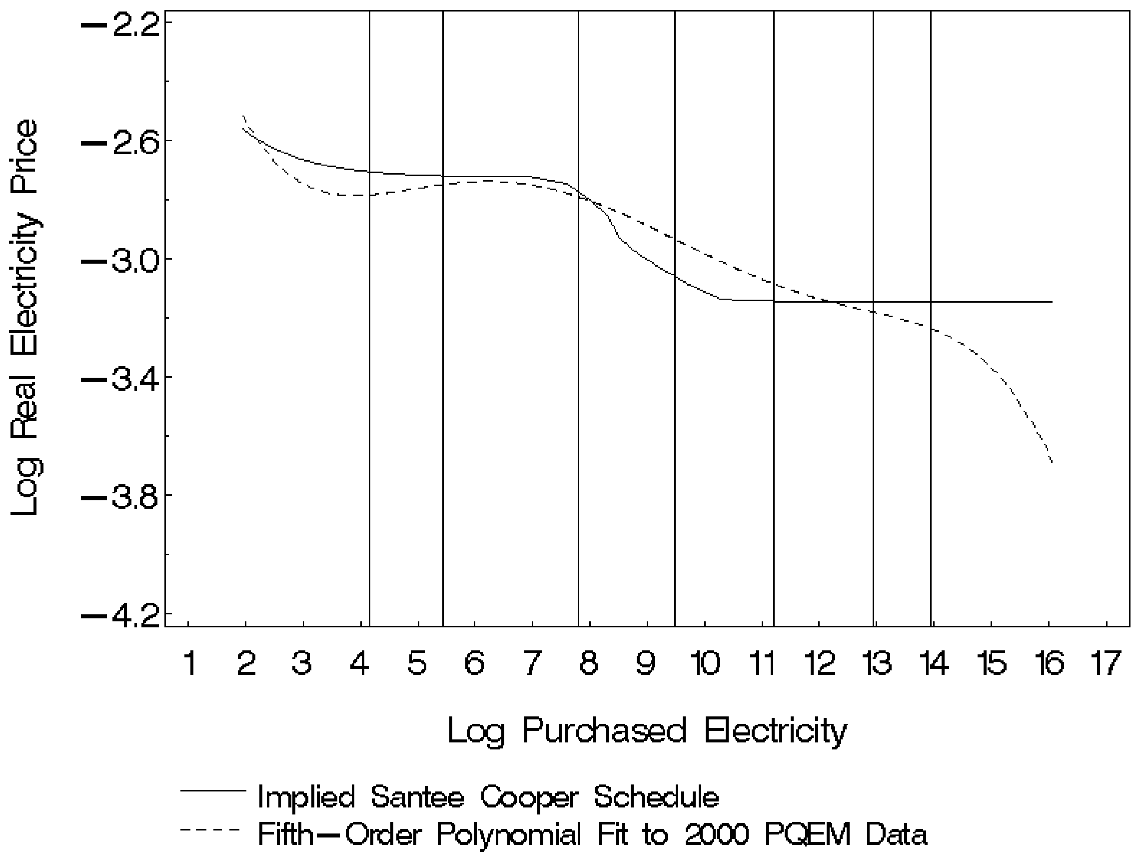
Figure 5. Log Electricity Price Fit to Fifth-Order Polynomials in Log Purchases, Selected Years



Source: Authors' calculations on PQEM data with part-year observations excluded.

Note: Elasticity values are calculated from shipments-weighted regressions of the log price on a fifth-order polynomial in log purchases.

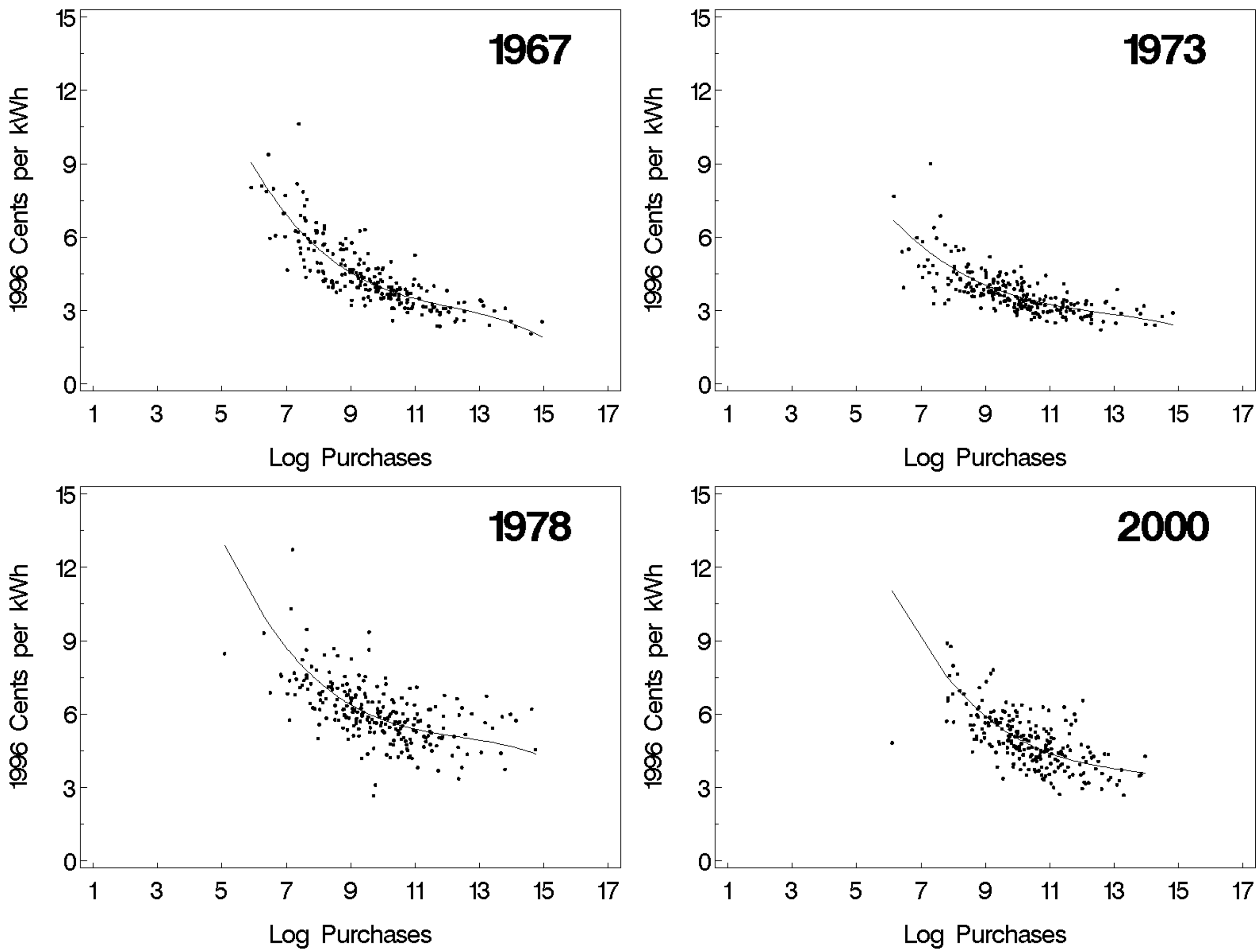
Figure 6. Average Elasticity of Price with Respect to Purchase Quantity, 1963-2000



Source: Authors' calculations on PQEM data and Santee Cooper tariff schedules.

Notes: The regression fit on the PQEM data controls for utility fixed effects. Vertical lines depict the simple average of the 1st, 5th, 25th, 50th, 75th, 95th and 99th percentiles of the shipments-weighted distribution of annual purchases for 1967, 1973, 1978, and 2000.

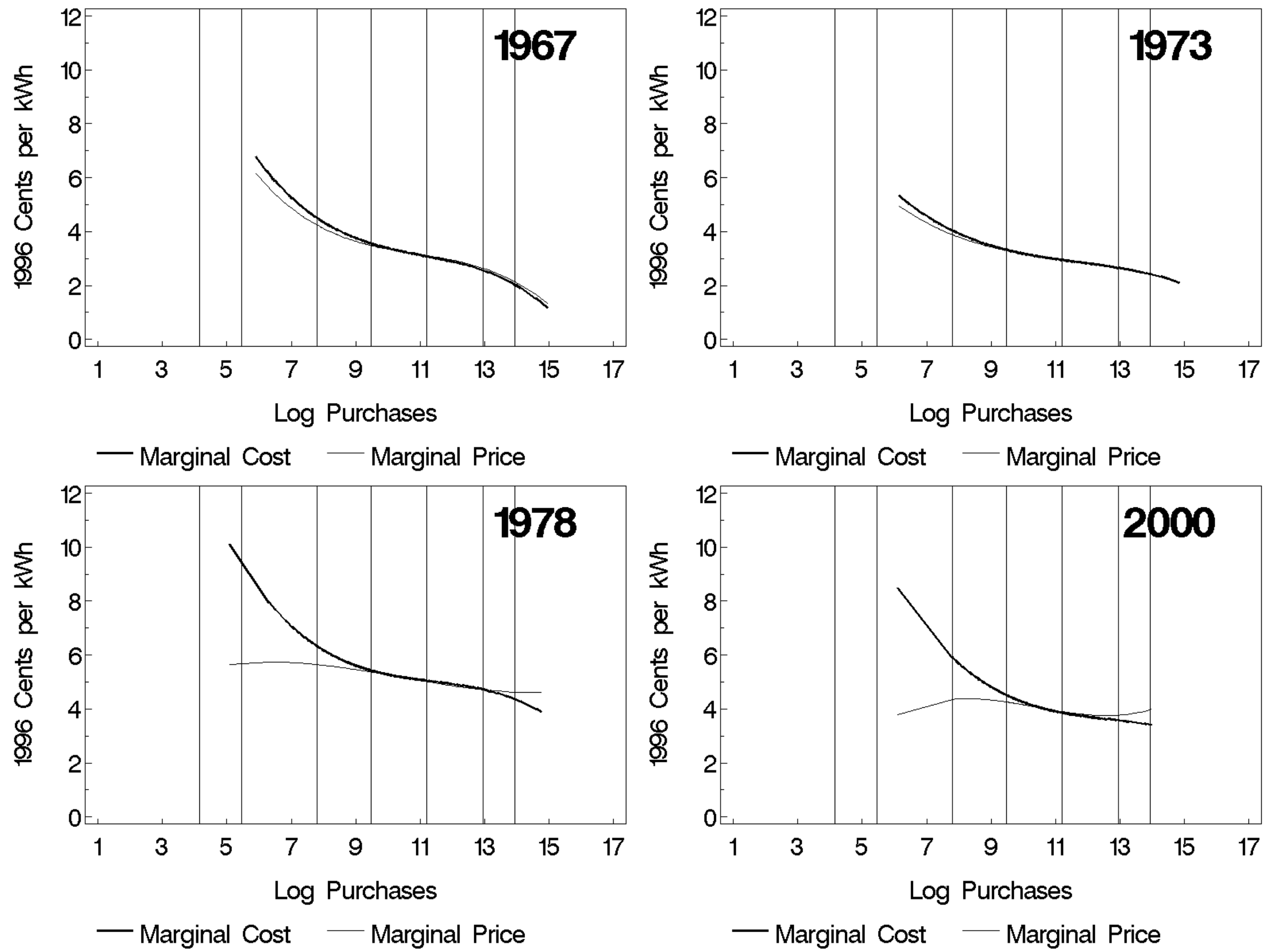
Figure 7. Comparison of Empirical and Implied Price-Quantity Schedules, 2000



Source: Authors' calculations on PQEM data with part-year observations excluded.

Notes: Each curve shows the fitted relationship between supply costs per kWh and annual customer purchases, evaluated at sample means of other covariates in the regression. The vertical coordinate for each plotted point is the sum of the fitted supply cost and the regression residual for a particular utility in the sample, as described in the text. Standard error bands for this figure are under construction.

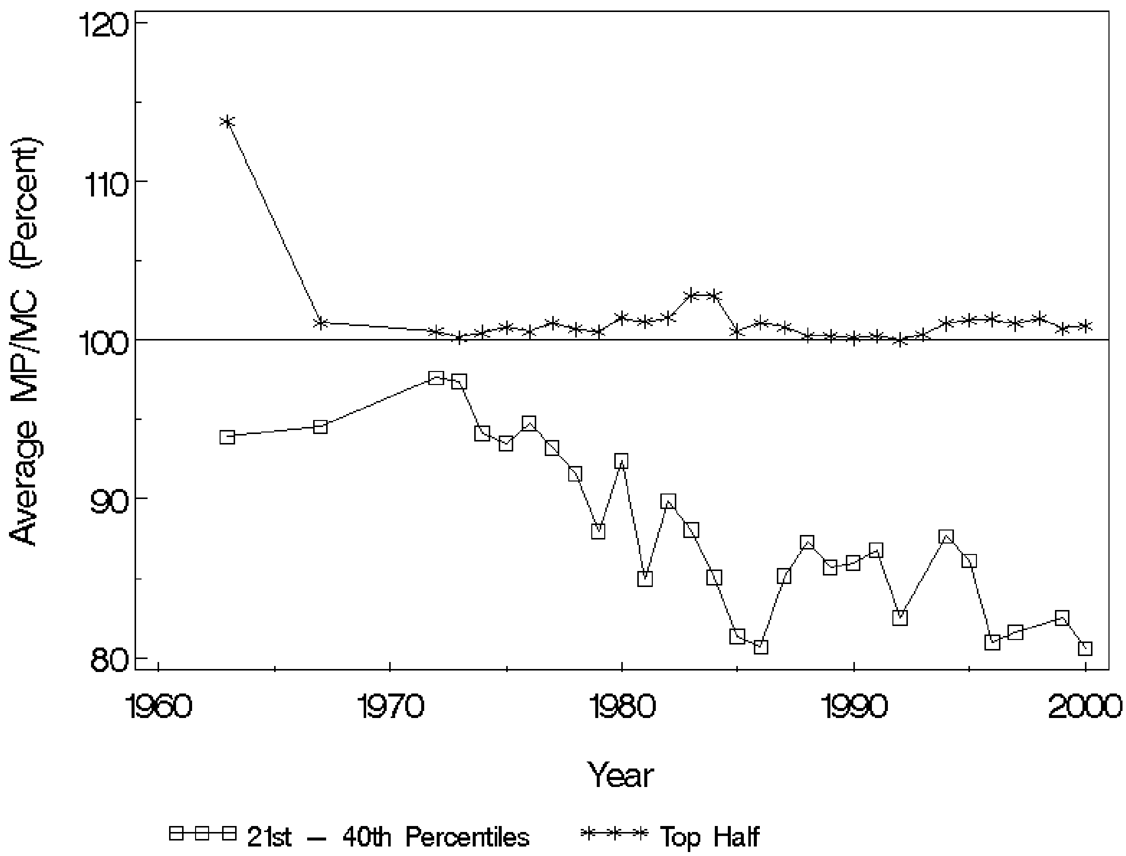
Figure 8. Electricity Supply Costs per kWh as a Function of Annual Customer Purchase Level, Selected Years



Source: Authors' calculations on PQEM data with part-year observations excluded.

Note: Vertical lines depict the simple average of the 1st, 5th, 25th, 50th, 75th, 95th and 99th percentiles of the shipments-weighted distribution of annual purchases for 1967, 1973, 1978, and 2000.

Figure 9. Marginal Cost and Marginal Price Curves Compared, Selected Years



Source: Authors' calculations on PQEM data with part-year observations excluded.

Notes: Each curve shows the marginal price per kWh as a percentage of the marginal supply cost per kWh for the indicated segment of the purchases distribution. Within each segment, average values of the MP/MC ratio are computed on a purchase-weighted basis. See the text for an explanation of the methods used to estimate the underlying marginal price and marginal cost schedules.

Figure 10. Marginal Price as a Percentage of Marginal Cost, Selected Segments of the Purchases Distribution, 1963-2000