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

By Steven J. Davis, Cheryl Grim, John Haltiwanger and Mary Streitwieser*

February 28, 2009

Abstract

We develop a large customer-level database to study electricity pricing to U.S. manufacturing plants from 1963 to 2000. We document tremendous dispersion in price per kWh, trace that dispersion to quantity discounts and spatial differentials, estimate the role of cost factors in quantity discounts, and test whether marginal price schedules conform to marginal cost and Ramsey pricing conditions. Our cost analysis and pricing tests rely on a novel empirical approach that exploits utility-level differences in the customer size distribution to estimate how supply costs vary with purchase quantity.

The results reveal that annual supply costs per kWh fall by more than half in moving from smaller to bigger purchasers, providing a clear cost-based rationale for quantity discounts. Before the mid 1970s, marginal price and marginal cost schedules are nearly identical, in line with efficient pricing. In later years, marginal supply costs exceed marginal prices for smaller manufacturing customers by 10% or more. In contrast to a clear role for cost factors, our evidence provides no support for a standard Ramsey-pricing interpretation of quantity discounts. Spatial dispersion in retail electricity prices among states, counties and utility service territories is large and rises over time for smaller purchasers.

JEL codes: L60, L94, Q40

Keywords: electricity pricing and supply costs, quantity discounts, Ramsey pricing, spatial price dispersion

*University of Chicago, NBER and American Enterprise Institute; Bureau of the Census; University of Maryland, Bureau of the Census and NBER; and Bureau of Economic Analysis, respectively. The analysis and results in this paper are attributable to the authors and do not necessarily reflect concurrence by the U.S. Bureau of the Census, the Bureau of Economic Analysis or the U.S. Department of Commerce. This work is unofficial and has not undergone the review accorded to official Census Bureau publications. All results were reviewed to ensure confidentiality. We thank Wayne Gray, Eddie Lazear, Catherine Wolfram, colleagues at the Berkeley Energy Group, Center for Economic Studies at the Census Bureau, Penn State, Tokyo University, University of Chicago, the July 2004 NBER Conference on Research in Income and Wealth and the 2005 Western Economic Association International Conference for many helpful comments. We are especially grateful to Rodney Dunn for comments and assistance with the EIA-861 data files. Davis and Haltiwanger gratefully acknowledge research support from the U.S. National Science Foundation under grant number SBR-9730667. Davis also acknowledges research support from the Stigler Center for the Study of the Economy and the State at the University of Chicago.

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]

---

[1] Hirsh (1999), EIA (2000), 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, 2003a, 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. By way of comparison, the hours-weighted standard deviation of log hourly production worker wages among manufacturing plants in the PQEM ranges from 39% to 43% between 1975 and 1993.[5] In other words, the dispersion in electricity prices among manufacturing plants is at least as great as the dispersion in their average hourly wages.

Figure 1 also reveals that the log price distribution underwent a great compression from 1967 to the late 1970s.[6] 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-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

---

[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] The PQEM lacks clean measures of hourly wages before 1975 or after 1993. See Davis and Haltiwanger (1991) for a detailed study of between-plant wage dispersion in the U.S. manufacturing sector.

[6] The temporary widening of dispersion in the mid 1970s reflects the 1973-74 oil price shock and differences among state public utility commissions in how rapidly they moved to approve higher electricity tariffs. In later years, automatic fuel price adjustment clauses came into widespread use in tariff schedules.

widened but never returned to the peaks of the 1960s. To the best of our knowledge, we are 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 shrank from -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 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.[7] 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 electric power declines with a customer's purchase quantity, an 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-

[7] 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.

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, and the resulting tariff schedules, do not seem well designed to achieve efficient pricing. Moreover, previous research offers no quantitative, theoretically grounded explanation for the sharp erosion in quantity discounts. 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 customer 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 cost-based rationale for quantity discounts.

We use the estimated price and supply cost schedules to construct marginal prices and marginal costs with respect to customer purchase quantity. Comparing the marginal schedules, we find no support for the Ramsey-pricing view that quantity discounts reflect smaller markups for more elastic demanders. However, the evidence is highly consistent with marginal cost pricing in the early years of our sample. Indeed, marginal price schedules are nearly identical to marginal cost schedules before the mid 1970s. In the upper half of the customer purchase distribution, they are nearly identical 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 prices by 10% or more.

We also consider the dispersion in average electricity prices among states, counties and utility service territories. We show that spatial price differentials are large, and that they display three interesting and somewhat surprising time-series patterns. First, in the lower deciles of the purchases distribution, spatial price dispersion widened over time. Second, and in glaring contrast, spatial price dispersion in the top deciles of the purchases distribution fell sharply from the 1960s to the late 1980s. Third, in the 1990s – when wholesale power markets grew rapidly – spatial price dispersion at the retail level did not diminish and even rose modestly over much of the purchases distribution.

The next section describes the PQEM database. Section 3 quantifies the dispersion of electricity prices between and within industries, states, counties, utilities, and purchase size classes. Section 4 discusses cost and demand influences on electricity pricing, describes key features of electricity tariffs, and develops evidence on electricity price-quantity schedules. Section 5 considers behavioral responses by customers that contribute to a negative relationship between electricity price and purchase quantity. Section 6 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 7 investigates whether marginal price schedules comport with efficient pricing and Ramsey pricing. Section 8 summarizes our main findings and identifies directions for future research.

2. The PQEM Database

The PQEM database derives principally from the U.S. Census Bureau's Annual Survey of Manufactures (ASM) and various files produced 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 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.[8] 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 help to assign manufacturing plants to electricity suppliers. As described in a companion paper (Davis et al., 2007b), 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 Energy Consumption Survey, another plant-level data source at the U.S. Bureau of the Census that relies on a different survey.

[8] 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.

We merged ASM plants to their electricity suppliers using a variety of sources, The Annual Electric Utility Reports, also known as the EIA-861 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. The EIA-861 files provide an immediate match to the utility for plants in counties served by a single utility. For many states, we are able to supplement the EIA-861 files with Geographic Information System (GIS) maps, a list of zip codes served by each utility or printed maps showing utility service territories. These supplemental sources of information enable us to construct accurate matches for counties served by more than one utility. We have some form of supplemental information for 18 states, accounting for 49% of electricity purchases and 54% of manufacturing shipments. For plants in states without this supplemental information, we created a "best match" utility indicator using the method described in Appendix A.

We also exploit publicly available information on the identity of those plants that purchase electricity directly from the six largest public power authorities.[9] 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 a distinct segment of the retail electricity market. We identified between 56 and 93 direct purchasers from public power authorities per year.

[9] 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 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).

Finally, we incorporated the State Energy Data 2000 files into the PQEM.[10] These files include annual data on fuel sources used for electricity generation by state from 1960 to 2000. We construct annual state-level fuel shares in electric power 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 697 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 90th quantile of the purchases distribution is 381 times the 10th quantile on a shipments-weighted basis and 739 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 purchase-weighted basis. While electricity costs are a modest percentage of labor costs for most plants, the top quartile (decile) of purchasers have labor costs that exceed 62% (201%) of labor costs. In other words, for the largest purchasers, electric power is a major cost of production.

3. Electricity Price Dispersion

After trending down for nearly a century, real electricity prices began to rise after 1973. They continued to rise for about ten years, before resuming the historical pattern of steady declines. See Figure 2, which shows that these broad trends held for all major

[10] This data is from the State Energy Data System (SEDS) on the Energy Information Administration Internet site, http://www.eia.doe.gov.

end-user groups.[11] We discuss the market, technological, regulatory and other factors behind these broad trends in an earlier working paper version of this study (Davis et al., 2007a). Here, we focus on price dispersion among manufacturing customers.

To decompose the variance of log electricity prices into within-group and between-group components (industry, region, etc.), write the overall variance as

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

where p_e is the log price of electricity for plant e, s_e is the weight for plant e, $\bar{p}$ is the overall weighted mean log price, $\bar{p}_g$ 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

[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 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.

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 document several other facts. First, spatial price differentials are large. County effects, for example, never account for less than 65% of the overall price variance on a purchase-weighted basis. Second, customer groups defined by electricity purchase quantities also account for a high percentage of overall price dispersion, especially in the 1960s.[12] Price dispersion among purchase-level groups fell by nearly half during our sample period, mostly between 1967 and 1977. Third, purchase level and utility jointly account for a high percentage of price dispersion throughout the past four decades. Groups defined by utility crossed with purchase deciles account for 71-90% of the overall purchase-weighted basis price variance.

Spatial price dispersion declined sharply over time on a purchase-weighted basis but 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. Closer examination of the data reveals that spatial price dispersion fell dramatically in the top decile of the purchases distribution (more heavily weighted in Table 3), but it rose in the bottom five deciles (more heavily weighted in Table 2). We highlight this pattern in Figure 3, which shows the evolution of spatial price dispersion for three selected deciles. To control for purchase

[12] 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.

quantity differences within deciles, we construct Figure 3 using residuals from annual customer-level regressions of log price on a polynomial in log purchases. As seen in Figure 3, there is an enormous decline from the late 1960 to the late 1980s in spatial price dispersion within Decile 10 (comprising the biggest purchasers). A similar, but more muted, pattern holds for Decile 9. The middle deciles exhibit little trend change in spatial price dispersion, as illustrated by Decile 6. The lower deciles exhibit trend increases in spatial dispersion, as illustrated by Decile 1. Another noteworthy pattern highlighted by Figure 3 is the lack of a downward trend in spatial price dispersion during the 1990s, when wholesale power markets grew rapidly. Sales of electricity for resale rose from 41% of generated power in 1991 to 61% in 2000 (EIA, 2003b, Tables ES and 6.2).

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. 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 customer purchase quantity capture most of the cross-sectional variation in electricity prices. The rest of the paper more fully explores the role of utility characteristics and purchase quantity in electricity pricing and supply costs.

4. Electricity Price-Quantity Schedules

4.1 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 characteristics provide a cost basis 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 qth unit of electricity, $C(q;Q)$ is the marginal cost of the qth unit when the utility's total quantity supplied is Q, $\eta[M(q),q]$ is the elasticity of demand for the qth 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.[13]

According to the Ramsey pricing condition (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. We test this implication below. We also test the efficient pricing condition, $M(q) = C(q;Q)$ for all q.

In our testing for Ramsey pricing in what follows, we focus on estimating the components of the left hand side of equation (2). That is, we generate estimates of $M(q)$ and $C(q)$. As such, we do not require direct estimates of either the demand elasticity $\eta[M(q),q]$ or the Ramsey parameter α. Instead, our approach is use the estimates of $M(q)$ and $C(q)$ to test for departures from marginal cost pricing and whether the departures occur for large or small purchasers. As noted above, the working hypothesis under Ramsey pricing is that larger purchasers have more elastic demand so that the marginal price should be more likely to exceed marginal cost for smaller purchasers.

[13] 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.

Focusing on the LHS of (2) has the advantage that estimating the marginal price with our data is relatively straightforward. The marginal price conceptually is derived from the price-quantity schedules within utilities. That is, the marginal price reflects the price for the marginal purchase of a customer of a utility as a function of purchase quantity. Since we have, on average, many observations per utility we can estimate the within utility price-quantity schedule precisely and in turn derive an estimate of the marginal price relationship. The greater challenge for the LHS of (2) is estimating the marginal cost schedule. As will become clear below, we use a novel approach towards the estimation of the marginal cost schedule.

4.2 Electricity Tariffs for Industrial Customers

Electricity tariffs for industrial customers usually include separate energy and "demand" charges.[14] 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

[14] 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.

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 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.[15] 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.[16] 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

[15] 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/.

[16] 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.

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 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 proceeds in the same spirit.

4.3 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.[17] We also exclude observations that display extreme seasonality or variation in production activity within the year, because customers with highly variable loads typically face special tariff schedules with higher charges.[18]

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.[19] 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 quantiles of the purchase distribution shrinks from 46 log points in 1967 to 26 log points in 1978,

[17] 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.
[18] 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.
[19] 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.

and the gap between the 5th and 95th purchase quantiles shrinks from 103 to 51 log points.[20] In short, there was a remarkable erosion of quantity discounts between 1967 and the late 1970s. We turn next to potential explanations for these strikingly large quantity discounts and their evolution over time.

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

5.1 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

[20] We also created analogs to Figure 5 for the five utilities with the largest number of customer-level observations (several hundred per year). All five utilities show the same basic pattern as in Figure 5.

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. Spatial sorting plays a bigger role 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 suggests that bigger purchasers are more sensitive to spatial price differences in their choice of location.

Even though spatial sorting plays some role after 1973, it is important to emphasize that the main findings of Figure 5 are robust to controlling for utility fixed effects. Figure 7 shows the within-utility price-quantity schedules for the same years as in Figure 5. It is apparent that even after controlling for utility fixed effects that there are large quantity discounts in all years but a substantial erosion of the quantity discounts in the 1970s. In the next subsection, we begin to explore the factors that underlie such within utility variation.

5.2 Other Behavioral Responses to Electricity Tariffs

In addition to location choice, several other behavioral responses by customers 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 incentives, and accepting curtailable or interruptible power. To help 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 exclude discounts for off-peak or high-voltage power.[21] These assumptions serve to foreclose quantity discounts that arise from behavioral responses to pricing incentives, isolating a “built-in” (non-behavioral) customer size effect. In contrast, the empirical price-quantity schedule reflects the built-in size effect *and* the behavioral responses by electricity customers.

Figure 8 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, but we now include utility fixed effects in the plant-level regression to isolate within-utility price variation.

Figure 8 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

[21] 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.

are essentially built into the tariff schedule according to the evidence in Figure 8.[22] Third, the large quantity discounts in the upper quartile of the distribution reflect 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.

5.3 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 discounts built into electricity tariff schedules within utilities. Both aspects are important, but they are relevant for different segments of the purchase distribution. Non-behavioral quantity discounts within utilities are important in the middle of the distribution, and behavioral responses to pricing incentives are important in the upper quartile. Both the responses to pricing incentives reflected in Figure 8 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. To explore the role of Ramsey-pricing we need to first estimate the supply cost relationship with purchase quantity to which we now turn.

6. Customer Purchase Quantity and Electricity Supply Costs

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

We now develop a method for estimating supply costs as a function of customer purchase amount. The method exploits the cross-sectional richness of the PQEM and, to the best of our knowledge, offers a novel approach to estimating customer-level supply

[22] 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.

cost schedules. 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 exploits the utility's revenue constraint, which states that average cost per kWh equals average price per kWh. Step two implies that we have a proxy for the average cost per utility. Step three exploits the first two steps by using cross-utility variation in the purchase distribution to estimate how costs per kWh of delivered electricity vary with customers' annual purchases. The discussion in section 4 provides ample evidence that utility-level costs will be a function of the purchase size distribution and it is this variation that we exploit in this approach. We carry out step three using regression methods to control for other factors that affect supply costs. Of particular concern here are other factors that may be correlated with the within utility purchase size distribution . 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

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

The revenue constraint implies that a utility's average cost per kWh equals its average price per kWh. Imposing this requirement 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 as well as non-sampling error discussed in more detail below. 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:

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

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 (WLS) and instrumental variables (IV) regression. We then use the γ estimates to trace out the supply cost schedule as a function of customer purchase quantity. Before turning to the results, a number of 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.[23] 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 authorities, and private investor-owned utilities. For similar reasons, we include controls for the size of the utility and for the shares of electric 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

[23] Davis et al. (2007) 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

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 creates 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.[24]

Third, the number of annual customer-level observations per utility in the PQEM ranges widely from a small handful to hundreds. 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 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 least squares.

Our identifying assumption for our baseline specification is that the above controls and methods accounts for other factors that influence costs at the utility level that may be correlated with the purchase size distribution. It may be of course there is residual unobserved heterogeneity that is correlated with the purchase size distribution.

---

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

[24] 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.

We know from section 5.1 that there appears to be a role, albeit modest, for spatial sorting. Such spatial sorting will potentially be captured by our controls – for example, very large purchasers are likely to locate in areas with lower cost fuels like hydroelectric power which we are controlling for in our baseline specification. Still, there may be other unobserved cost factors that contribute to spatial sorting. To explore the sensitivity of our results to this issue, we also consider below robustness exercises to address this possibility. In particular, we estimate our supply cost model on a restricted sample that excludes the largest purchasers. The argument here is that it should be the latter establishments that are the most sensitive to such unobserved factors.

6.2 Supply Cost Schedule Estimation Results

Table 5 reports the WLS 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 reflect 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.

Municipal and cooperative utilities have lower estimated supply costs in the 1960s and early 1970s, after controlling for other factors, and the cost advantage 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.[25] The estimated effects of power source are sizable.

[25] We were initially surprised that hydro power did not yield the lowest implied supply costs in all years. However, in an analysis of fuel prices we found that the real price of coal fell steadily from 1980 onwards

For example, the 1967 estimates imply that shifting 10% of power generation from coal to hydro involves a 3.6% 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, strongly confirming the statistical significance of purchase quantity as a determinant of supply costs. Table 6 and Figure 9 report the estimated supply cost schedules. Figure 9 also shows a scatter plot of mean log customer purchases for each utility, $\overline{lq_{1g}}$, against the sum of the corresponding fitted cost value $\tilde{P}_g = \left(\overline{X_g \hat{b}}\right) + \hat{\gamma}_1 \overline{lq_{1g}} + \hat{\gamma}_2 \left(\overline{lq_{1g}}\right)^2 + \hat{\gamma}_3 \left(\overline{lq_{1g}}\right)^3$ and the utility's regression residual. 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 in all years from 1963 to 2000. We re-estimated the supply cost regressions by IV using the approach described above, and obtained essentially the same findings. These results provide strong evidence of powerful, cost-based reasons for large quantity discounts in electricity pricing to industrial customers.

Recall that one concern is that in spite of our extensive controls for other cost factors, there may be unobserved cost factors that are correlated with the purchase size distribution of the utility. The endogenous location of large purchasers with respect to unobserved cost factors is one candidate source of concern. To test the sensitivity of our results to this issue, we estimated the supply cost relationships on a restricted sample that

---

and coal is the omitted fuel group in Table 5. Caution must be used in interpreting the fuel share coefficients in Table 5 since there are many other regressors in Table 5. However, we have estimated a simple regression of the price of electricity at the utility level on only fuel cost shares and find that the hydro share coefficient becomes positive in 1993 reflecting the falling relative price of coal.

omits the largest purchasers (we omitted any plant that has energy costs that exceed twenty percent of the total value of shipments). We find that the patterns reported in Table 6 and Figure 9 are very similar with this restricted sample. In the next section, we discuss this robustness check in more detail in exploring the robustness of our findings on marginal cost vs. marginal prices.

We also computed the average supply-cost elasticity with respect to customer purchase quantity for each year and compared it to the average price elasticity with respect to purchase quantity (Figure 6). The comparison yields two interesting results. First, the average cost elasticity is consistently somewhat larger in magnitude than the average price elasticity, indicating that (average) supply costs fall more rapidly with purchase quantity than (average) price per kWh. Second, longer term swings in the average cost elasticity closely mirror the swings in the average price elasticity in Figure 6. This time-series pattern reinforces the inference derived from the cross-sectional evidence that cost factors drive large quantity discounts in electricity pricing. We examine this inference in a more structured manner in the next section.

7. Evaluating the Pricing Structure

7.1 Is Pricing Efficient on the Purchase Quantity Margin?

Pricing efficiency requires that marginal prices for successive increments of electrical power equal marginal supply costs at all points on the customer purchase distribution. This is a demanding requirement in our context, because the range of purchases is enormous. We now test whether this condition holds in the data. Earlier empirical studies also consider retail pricing efficiency in the electric power industry. Examples include Meyer and Leland (1980), Hayashi, Sevier and Trapani (1985) and

Nelson, Roberts and Tromp (1987). However, these studies evaluate pricing differences across classes of customers – residential, industrial and commercial – from the vantage point of efficiency, Ramsey pricing, and rate of return regulation. They do not consider pricing efficiency on the purchase quantity margin. Indeed, we are unaware of any previous study that tests marginal cost and Ramsey pricing conditions on the purchase quantity margin, even though the issue receives much attention in theoretical works.[26] See Brown and Sibley (1986) and Wilson (1993) and references therein. Our empirical assessment of pricing on the purchase quantity margin complements the well-developed theoretical literature on the topic.

The marginal price schedule is directly derivable from the type of within utility price-quantity schedules shown in Figure 7. However, for purposes of comparing the marginal price to the marginal cost curves, we make a few modest adjustments to the estimation methodology of the within utility price-quantity schedules to facilitate apples-to-apples comparisons. Specifically, we omit plants with annual purchases outside the range of mean log purchases in the utility-level data. Also, consistent with the cost estimation methodology, we re-estimate the price-quantity schedules by regressing price per unit (not logged) on a third order polynomial in log customer purchases. The price-quantity schedules estimated using this alternative specification closely mimic the patterns exhibited in Figure 7.

Using the resulting fitted price-quantity schedule, it is easy to calculate the corresponding marginal price schedule. Let $T(q) = qP(q)$ be the total electricity tariff

[26] Peltzman (1971) considers electricity pricing on the purchase quantity margin, but he lacks the cost data needed for an assessment of pricing efficiency.

paid by a plant that purchases q kWh, where $P(q)$ is the average price per kWh. We compute the marginal price schedule as

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

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 estimated supply cost schedules of the type displayed in Figure 8. That is, $TC(q) = qAC(q)$ so we can derive $MC(q)$ from the estimated $AC(q)$ curves in Figure 8.

One challenge in estimating the average cost and, in turn, marginal cost schedules using utility level data is that the number of utility-level observations that have sufficient customer-level observations to yield a reliable estimate is limited. To improve precision of our supply cost relationships, we take advantage of the fact that each ASM panel is an independently drawn random sample. To exploit this sample design feature, we pool customer-level observations over year-pairs that straddle ASM panel changeovers before we construct the utility-level data. This pooling method yields more customer-level observations per utility and a larger number of usable utility-level observations, thereby improving estimation efficiency in the supply cost regressions. We estimate these regressions using the same specification and weighted least squares method as before except for the addition of a year control.

Figure 10 displays the marginal price and marginal cost schedules for selected years, along with bootstrapped standard error bands for the marginal cost schedules. (Standard errors for marginal prices are extremely small, and we ignore them in the discussion that follows.) The marginal price and cost schedules are remarkably similar in both 1967 and 1973/74, strongly confirming the central implication of pricing efficiency on the purchase quantity margin. After 1973/74, however, a gap opens between marginal cost and marginal price in the lower deciles of the purchases distribution. The gap is sizable, with marginal cost exceeding marginal price by 10% or more for smaller purchasers.

An interesting implication of Figure 10 is that the fluctuations in the marginal price schedules over time are largely mimicked by the marginal cost schedules. To help interpret this finding, it is useful to note that the marginal price schedule at any level of purchases will be the sum of two components – one is the price-quantity relationship itself and the other is the slope of the price-quantity relationship. The slope of the price quantity relationship is negative but becomes less negative during the 1970s. In addition, it is apparent from Figure 7, that the price-quantity schedule itself shifts up over the 1970s and remains at a higher level through 2000. Both factors taken together contribute to the pattern in Figure 10 showing that the marginal price relationship shifts up in 1978-79 relative to 1973-74 and remains at a higher level through 1998-99. The remarkable finding in Figure 10 is that not only did the marginal price relationship shift up but so did the marginal cost relationship. Put differently, Figure 10 suggests that the erosion of the quantity discounts in the 1970s is driven by cost factors.

To construct a more powerful formal test for the null hypothesis of pricing efficiency, we now pool the data over several years. We evaluate pricing efficiency in the "early years" 1963, 1967, 1973 and 1974 and the "recent years" 1988, 1993, 1998 and 1999. The early years predate the departures from pricing efficiency suggested by Figure 9, and the recent years postdate them. We selected these particular years because they involve eight independently drawn random samples of manufacturing plants. In pooling the data over years, we introduce year controls that allow for marginal costs to shift over time in a manner that is uniform with respect to purchase quantity.

Table 7 reports the pooled-sample estimates and bootstrapped standard errors for early and late years. The upper panel extends our previous pooling method for calculating utility-level statistics from customer-level observations. This method results in many customer-level observations per utility but only one observation per utility in the supply cost regression. Hence, this method exploits only between-utility variation to estimate the cost schedules. The lower panel calculates utility-level statistics from customer-level data first and then pools over years. This method results in fewer customer-level observations per utility but up to four observations per utility in the supply cost regression. Under this method, we assume that utility-level error terms in the supply cost regression are uncorrelated over time. This second method exploits between- and within-utility variation to estimate the cost schedules.[27]

The two pooling methods yield a similar pattern of point estimates that shows sizable departures from pricing efficiency in the later years for smaller customers. Marginal prices are roughly 10% below marginal costs at the 20th percentile of the purchase quantity distribution in the later years. The second pooling method also yields evidence against marginal cost pricing for smaller customers in the early years, but the deviation from pricing efficiency is much smaller, amounting to less than 5% of marginal

[27] Our results could potentially be affected by retail electricity market restructuring that occurred in the late 1990s. Specifically, California, Massachusetts, New Hampshire, New York, and Rhode Island enacted retail market restructuring in 1998. Five more states enacted retail restructuring in 1999 (Arizona, Delaware, Illinois, New Jersey, and Pennsylvania). Connecticut, Maryland, and Maine enacted retail restructuring in 2000. As a robustness check, we recreated Table 7 for utilities in states without active retail electricity market restructuring. We still see the same general results, but they are no longer statistically significant.

cost. In line with Figure 10, Table 7 yields no evidence of departures from pricing efficiency in the middle and upper portions of the purchase quantity distribution.[28]

A potential issue with Figure 10 and Table 7 is that the test results may be affected by inaccuracies in the assignment of customers to utilities. To address this issue, we created a sample that restricts attention to utilities and customers with highly accurate assignments. When a county is served by a single utility, we know the correct assignment of customer to utility from the EIA-861 files. We also know the correct assignment with near certainty in those states with detailed GIS data on utility service territories. We used the detailed GIS information available for certain states to estimate how the cruder information available in other states affects the probability of an accurate assignment. Our method, detailed in Davis et al. (2007b), yields a probability of an accurate assignment for each customer and an estimated accuracy rate for each utility.

In the full sample that underlies Table 7 and Figure 10, we estimate that 67% of customers are assigned to the correct utility.[29] To construct a restricted sample, we discarded customers with low probabilities of an accurate assignment and discarded utilities with low accuracy rates. (See Appendix A for details.) The resulting limited sample has an estimated match accuracy rate of 88 percent. The number of utility-level

[28] One potential issue with the results shown in Table 7 is the effect of state-level electricity retail market restructuring that began in the 1990s. The earliest states to enact retail competition in electricity markets did so in early 1998 (Joskow, 2005). Several states undertook major changes in the structure and operation of their retail electricity markets in the late 1990s: California, Massachusetts, New Hampshire, New York, and Rhode Island in 1998; Arizona, Delaware, Illinois, New Jersey, and Pennsylvania in 1999; and Connecticut, Maryland, and Maine in 2000 (EIA, 2003c). As a robustness check, we recreated Table 7 dropping all observations for these states during and after the retail restructuring years. The results for Panel A in the alternate version of Table 7 are nearly identical to those shown in the text. The results for Panel B show the same pattern, but the departure from marginal cost pricing at the 20th percentile of the customer size distribution is no longer statistically significant in the later period.

[29] The estimated accuracy rate is calculated in a shipments-weighted manner. The actual accuracy rate is probably somewhat higher, because the 67% figure does not account for the hand-adjusted assignments that

observations available for the Table 7 analysis using the limited sample is about 70% smaller than before for Panel A and about 45% smaller for Panel B.

The restricted sample results are very similar to the full sample results, except that the smaller number of utility-level observations produces bigger standard errors. There is no evidence in the restricted sample of departures from marginal cost pricing in the middle or upper parts of the purchase quantity distribution. The point estimate for marginal cost minus marginal price at the 20^{th} percentile is somewhat larger in the limited sample, but we cannot reject the null hypothesis of no difference under the pooling method of Panel A. The discrepancy between marginal price and marginal cost at the 20^{th} percentile is statistically significant at the 10% level under the pooling method of Panel B. In short, the restricted sample results are consistent with the full sample results, but the statistical evidence for departures from marginal cost pricing is weaker.

Recall from the prior section that another robustness check we conducted is to exclude plants that are the largest purchasers from the analysis (we restricted plants with electricity costs greater than twenty percent of the total value of shipments). For this restricted sample, we also found results that are similar to our full sample results but with larger standard errors. That is, with this restricted sample, there is still no evidence of departures from marginal cost pricing in the middle and upper parts of the purchase quantity distribution. At the 20^{th} percentile, the point estimates in both panels A and B still yield reasonably large estimated differences in the marginal cost minus marginal price. For example, with this restricted sample, for the later period (1988, 1993, 1998, 1999) the estimate for panel A of the difference is -0.64 and for panel B it is -0.49.

---

we made based on visual inspections of utility service territory maps in nine states. The same point applies to the 88% accuracy rate for the restricted sample.

However, the differences are no longer statistically significant given the increase in the estimated standard errors. In short, the restricted sample results are consistent with the full sample results showing little evidence of departures from marginal cost pricing.

7.2 Does Ramsey Pricing Play a Role?

Figure 10 and Table 7 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 5, 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 we have seen 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 can 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.

8. Concluding Remarks

In this study, we documented tremendous dispersion in the price per kWh that manufacturers pay for electricity. Spatial price differentials and quantity discounts account for all but a small fraction of the dispersion in prices. We also developed and implemented a new method for estimating how supply costs vary with customer purchase quantity. The estimation reveals that annual supply costs per kWh fall by more than half in moving from smaller to bigger purchasers, providing a clear cost-based rationale for quantity discounts.

We applied our estimated cost and price schedules to test for pricing efficiency on the annual purchase quantity margin and to evaluate a traditional Ramsey-pricing interpretation of quantity discounts. Somewhat to our surprise, the data are remarkably consistent with marginal cost pricing. The exception is pricing to smaller manufacturing customers after the mid 1970s. The marginal cost of incremental purchases for these customers exceeds the marginal price by more than 10% in the 1980s and 1990s. This deviation from marginal cost pricing is inconsistent with a standard Ramsey-pricing story, which predicts that marginal cost lies below marginal price, and more so for smaller purchasers. Our tests for marginal cost pricing and Ramsey pricing on the purchase quantity margin complement a well-developed theoretical literature on the topic.

What caused the departure from pricing efficiency for smaller customers after the mid 1970s? An answer to that question is beyond the scope of this paper, but we suggest two 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 mentioned in Section 3, the rise in real electricity prices from 1973 to 1983 reversed a decades-long trend. Perhaps utility companies or their regulators 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 after real electricity prices resumed a downward trend. Another difficulty is that, under two-part tariffs, subsidies need not involve departures from marginal cost pricing.

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 Madison 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, page 794) Ironically, these moves toward more aggressive intervention in rate design were often promoted as efforts to implement marginal-cost pricing principles. Our evidence shows that greater involvement in the 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 deviations from efficient pricing merits investigation.

Our results also identify some noteworthy aspects of spatial price differentials. Spatial price dispersion declined sharply from the late 1960s to the late 1980s for the largest purchasers, but it rose over time in the lower half of the purchases distribution (Figure 3). The expansion of wholesale power markets in the 1990s had no apparent effect on spatial price dispersion at the retail level for manufacturing customers. It strikes us as something of a puzzle that rapid expansion of wholesale power markets in the 1990s had so little impact on spatial price dispersion at the retail level.

Appendix A. Assigning Manufacturing Plants to Electric Utilities

This appendix provides an overview of our methods for assigning manufacturing plants to electric utilities. See Davis et al. (2007b) for a more detailed discussion and an evaluation of assignment accuracy.

The EIA-861 data do not determine a unique, unambiguous assignment in counties served by more than one electric utility.[30] We addressed this issue using several approaches, depending on available information. First, we created a "best-match" utility indicator for each county. Given a list of utilities with industrial customers in the county, the indicator identifies the utility with the largest statewide revenues from sales to industrial customers. Based on each manufacturing plant's county of operation, our default assignment method (in the absence of better information described below) is to assign the plant 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.

Second, we use Geographic Information System (GIS) maps of electric utility service areas for Kansas, Kentucky, Maine, Minnesota, Ohio and Wisconsin.[31] These six states account for 13.4% of plants, 14.2% of employment, 14.8% of payroll, 17.3% of electricity purchases, 15.3% of electricity expenditures and 15.1% of shipments in the PQEM. We use street address to assign latitude and longitude to manufacturing plants and then overlay the GIS service area map to determine the electric utility that serves the

[30] 459 counties are served by a single utility, 776 are served by 2 utilities, 791 are served by 3 utilities, 535 are served by 4 utilities, 441 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.
[31] The Minnesota GIS map we obtained is an unofficial version.

plant. Using this approach, we can construct highly accurate matches for most plants in states with GIS maps of utility service areas.

Third, for California, New York and Rhode Island, we obtained a list of utilities that operate in each zip code. These three states account for 18.2% of plants, 16.6% of employment, 17.5% of payroll, 9.8% of electricity purchases, 13.3% of electricity expenditures and 14.7% of shipments in the PQEM. Because zip codes cover much smaller areas than counties, the zip code data enables us to construct a unique match in most cases. When more than one utility serves a given zip code, we assigned plants based on the same type of “best match” approach as described above for counties.

Fourth, we adjusted our county-based assignments in some cases based on visual inspections of maps showing utility service territories in Florida, Illinois, Louisiana, Maryland, Michigan, Missouri, Pennsylvania, South Dakota and Wyoming. These states account for 23.3% of plants, 23.7% of employment, 24.1% of payroll, 21.4% of electricity purchases, 23.2% of electricity expenditures and 24.3% of shipments in the PQEM. We inspected the utility service territories for each county, and if one utility clearly covers most of the county, we assign that utility to all plants in the county. If the county is not covered primarily by a single utility, we retained the county-based utility match.

As noted in the main text, we exploit publicly available information on the identity of plants that purchase electricity directly from the six largest public power authorities. In all other cases, our assignment procedures rely on the assumption that a plant’s location determines its electricity supplier. This assumption works for the period of time covered by our data, because electric utilities were monopolies at the retail distribution level.

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 occur at the very end of the period covered by our data.

References

Besanko, David, Julia D'Souza and S. Ramu Thiagarajan. 2001. "The Effect of Wholesale Market Deregulation on Shareholder Wealth in the Electric Power Industry." *Journal of Law and Economics*, 44(1): 65-88.

Borenstein, Severin. 2002. "The Trouble with Electricity Markets: Understanding California's Restructuring Disaster." *The Journal of Economic Perspectives,* 16(1): 191-211.

Borenstein, Severin and Stephen P. Holland. 2005. "On the Efficiency of Competitive Electricity Markets with Time-Invariant Retail Prices." *The RAND Journal of Economics,* 36(3): 469-93.

Brown, Stephen J. and David S. Sibley. 1986. *The Theory of Public Utility Pricing.* Cambridge: Cambridge University Press.

Caywood, Russell E. 1972. *Electric Utility Rate Economics.* New York: McGraw-Hill Book Company.

Cowern, Edward H. 2001. "Power and Energy: Factors that Determine Industrial Electric Bills." The Cowern Papers presented by Motors and Drives, LLC. http://www.motorsanddrives.com/.

Cudahy, Richard D. and J. Robert Malko. 1976. "Electric Peak-Load Pricing: Madison Gas and Beyond." *Wisconsin Law Review,* 47: 47-78.

Davis, Steven J., Cheryl Grim, John Haltiwanger and Mary Streitwieser. 2007a. "Electricity Pricing to U.S. Manufacturing Plants, 1963-2000." U.S. Census Bureau, Center for Economic Studies, Working Paper No. CES 07-28, October. Available at http://ssrn.com/abstract=1028529.

Davis, Steven J., Cheryl Grim, John Haltiwanger and Mary Streitwieser. 2007b. "Prices and Quantities of Electricity in the U.S. Manufacturing Sector: A Plant-Level Database and Public-Release Statistics, 1963-2000." November. Available at http://www.econ.umd.edu/~haltiwan/pqem.pdf.

Davis, Steven J. and John Haltiwanger. 1991. "Wage Dispersion Between and Within U.S. Manufacturing Plants, 1963-1986." In *Brookings Papers on Economic Activity: Microeconomics*, ed. Martin Neil Baily and Clifford Winston, 115-200. Washington, D.C.: The Brookings Institution.

EIA [Energy Information Administration]. 2000. "The Changing Structure of the Electric Power Industry 2000: An Update." Energy Information Administration, U.S. Department of Energy: No. DOE/EIA-0562(00).

EIA [Energy Information Administration]. 2003a. "Annual Energy Review 2002." Energy Information Administration, U.S. Department of Energy: No. DOE/EIA-0384(2002).

EIA [Energy Information Administration]. 2003b. "Electric Power Annual 2002." Energy Information Administration, U.S. Department of Energy: No. DOE/EIA-0348(2002).

Energy Information Administration (EIA). 2003c. "Status of State Electric Industry Restructuring Activity." Available at http://www.eia.doe.gov.

ELR [Environmental Law Reporter]. 1975. "Electric Utility Rate Design: The Move Toward Peak-Load Pricing." *Environmental Law Reporter*, 5(ELR 10084).

Foster, Lucia, John Haltiwanger and C. J. Krizan. 2001. "Aggregate Productivity Growth: Lessons from Microeconomic Evidence." In *New Directions in Productivity Analysis*, ed. Edward Dean, Michael Harper and Charles Hulten, 373-414. Chicago: The University of Chicago Press.

Goldman, M. Barry, Hayne E. Leland, and David S. Sibley. 1984. "Optimal Nonuniform Prices." *Review of Economic Studies*, 51(2): 305-19.

Hayashi, Paul M., Melanie Sevier and John M. Trapani. 1985. "Pricing Efficiency under Rate-of-Return Regulation: Some Empirical Evidence for the Electric Utility Industry." *Southern Economic Journal*, 51(3): 776-92.

Hirsh, Richard F. 1999. *Power Loss: The Origins of Deregulation and Restructuring in the American Electric Utility System*. Cambridge, Massachusetts: The MIT Press.

Joskow, Paul L. 1979. "Public Utility Regulatory Policies Act of 1978: Electric Utility Rate Reform." *Natural Resources Journal*, 19(October): 787-809.

Joskow, Paul L. 2005. "The Difficult Transition to Competitive Electricity Markets in the United States." In *Electricity Deregulation: Choices and Challenges*, ed. J. Griffin and S. Puller, 31-97. Chicago: University of Chicago Press.

Joskow, Paul L. and Richard Schmalensee. 1983. *Markets for Power: An Analysis of Electric Utility Deregulation*. Cambridge, Massachusetts: The MIT Press.

Meyer, Robert A. and Hayne E. Leland. 1980. "The Effectiveness of Price Regulation." *Review of Economics and Statistics*, 62(4): 555-66.

Nelson, Jon P., Mark J. Roberts and Emsley P. Tromp. 1987. "An Analysis of Ramsey Pricing in Electric Utilities." In *Regulating Utilities in an Era of Deregulation*, ed. Michael Crew, 85-110. New York: Macmillan.

Peltzman, Sam. 1971. "Pricing in Public and Private Enterprises: Electric Utilities in the United States." *Journal of Law and Economics*, 14(April): 109-47.

Van Biesebroeck, Johannes. 2004. "Robustness of Productivity Estimates." National Bureau of Economic Research, Inc., NBER Working Papers: No. 10303.

Wilson, Robert B. 1993. *Nonlinear Pricing.* New York: Oxford University Press.

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]	697								
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[e]								
Weighting Method	1	5	10	25	50	75	90	95	99
Shipments	.07	.30	.70	3.22	16.4	89.2	267	444	1,500
Purchases	.20	1.08	2.84	13.58	85.9	452	2,100	4,185	14,241
Weighting Method	Quantiles of Electricity Costs as a Percent of Total Labor Costs[e]								
Shipments	0.4	1.1	1.5	2.5	4.7	10.2	25.7	46.3	197.2
Purchases	1.1	2.1	3.0	6.1	17.2	61.7	201.0	305.3	3,461

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. (2007) for additional information.
[c] There are 684 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).
[e] For disclosure reasons, the quantiles shown above are averages of plant-level observations in three quantiles, the quantile shown and the two surrounding quantiles (e.g., quantile 50 as shown is the average of observations in quantiles 49, 50, and 51).

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	12.7	13.2	17.9	15.1	22.2	20.9	21.3
Between Standard Deviation	.123	.146	.153	.134	.152	.135	.175	.177	.166
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 (697)									
Between Variance as % of Total	20.4	22.1	23.5	44.3	58.3	45.7	52.9	48.9	47.3
Between Standard Deviation	.185	.220	.208	.246	.274	.234	.271	.272	.247
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 (4,252)									
Between Variance as % of Total	74.8	70.4	56.6	60.9	74.0	67.6	75.4	72.5	70.3
Between Standard Deviation	.354	.393	.323	.288	.309	.285	.324	.331	.302
Utility x Purchase Centile (32,142)									
Between Variance as % of Total	84.1	79.6	67.7	71.5	83.1	78.5	85.1	83.8	81.9
Between Standard Deviation	.375	.418	.353	.312	.327	.307	.344	.356	.325

+ 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	.247	.240	.211	.132	.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 (697)									
Between Variance as % of Total	67.2	58.4	52.3	60.0	65.2	56.8	59.1	55.0	52.7
Between Standard Deviation	.430	.422	.346	.335	.354	.323	.366	.324	.278
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 (4,252)									
Between Variance as % of Total	89.7	83.2	71.2	74.8	79.2	78.3	82.9	76.2	74.3
Between Standard Deviation	.496	.503	.404	.374	.391	.379	.434	.382	.330
Utility x Purchase Centile (32,142)									
Between Variance as % of Total	94.7	91.1	81.6	84.5	88.4	88.3	91.7	87.5	86.3
Between Standard Deviation	.510	.527	.432	.398	.413	.403	.456	.409	.356

[+] 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	26**	7	-4	10
	(9)	(8)	(12)	(10)
Private Ownership	35***	21***	14***	8*
	(4)	(3)	(4)	(3)
Fraction of Utility Total Revenue from Industrial Customers < 25%	-6	1	2	5
	(7)	(6)	(5)	(4)
Fraction of Utility Total Revenue from Industrial Customers 25-50%	-5	-4	-5	3
	(7)	(6)	(5)	(4)
Share of Power From Hydro	-35***	-48***	-58***	16*
	(5)	(5)	(6)	(8)
Share of Power From Nuclear	417***	49***	13	46***
	(82)	(13)	(7)	(8)
Share of Power From Oil and Natural Gas	-4	-5	7	43***
	(3)	(4)	(5)	(7)
Adjusted R-Square	0.76	0.65	0.60	0.63
Test: Utility Size Measures = 0	0.00	0.35	0.47	0.62
Test: Customer Size Measures = 0	0.00	0.00	0.00	0.00
Test: Ownership Measures = 0	0.00	0.00	0.00	0.07
N	253	272	298	290

* $p<0.05$, ** $p<0.01$, *** $p<0.001$

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 (GWh)	Percentile of Purchases Distribution	Supply Cost per kWh in 1996 Cents			
		1967	**1973**	**1978**	**2000**
0.53	10	8.03	6.26	9.63	10.36
2.43	25	5.68	4.86	7.45	7.39
13.1	50	4.20	3.86	6.06	5.37
73.9	75	3.44	3.22	5.36	4.30
229	90	3.10	2.92	5.06	3.93
422	95	2.91	2.76	4.90	3.79
1,130	99	2.49	2.49	4.57	3.57

Notes:

1. The supply-cost schedules are derived from the regressions reported in Table 5 and described in Section 6.1. 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.

Table 7. Tests of Pricing Efficiency with Alternative Pooling Methods

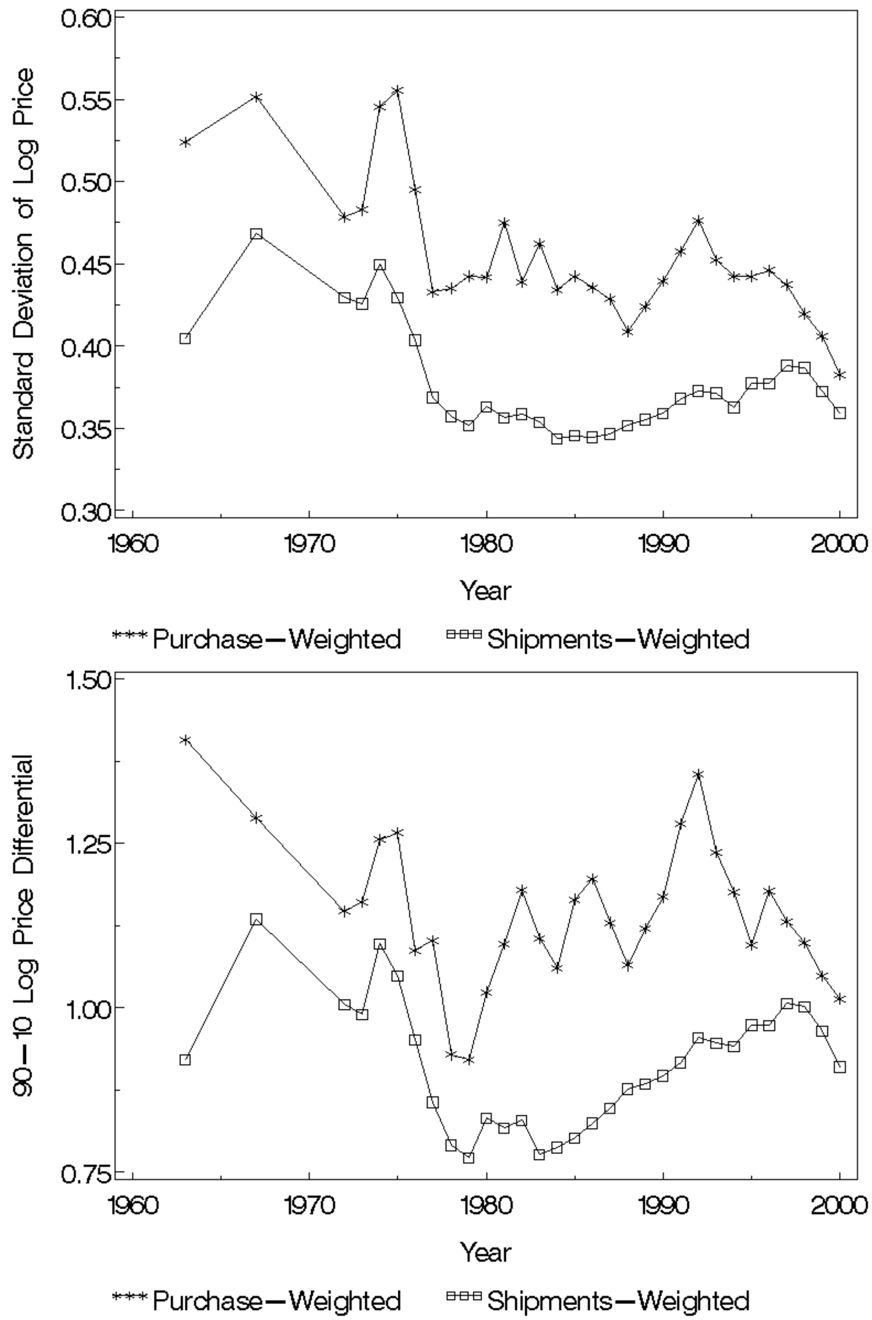
A. Customer-Level Data Pooled over Years before Calculating Utility-Level Statistics

	Marginal Price (1996 ¢ / kWh)	**Marginal Cost (1996 ¢ / kWh)**	**Standard Error of Marginal Cost (1996 ¢ / kWh)**	**Difference: MP - MC (1996 ¢ / kWh)**
1963, 1967, 1973, 1974		***N* = 432**		
20th	4.62	4.95	0.17	-0.33
50th	3.66	3.81	0.17	-0.14
80th	3.20	2.99	0.16	0.21
1988, 1993, 1998, 1999		***N* = 495**		
20th	6.25	7.08	0.35	-0.82
50th	5.06	5.16	0.35	-0.10
80th	4.20	3.90	0.34	0.30

B. Utility-Level Statistics Calculated from Customer-Level Data before Pooling

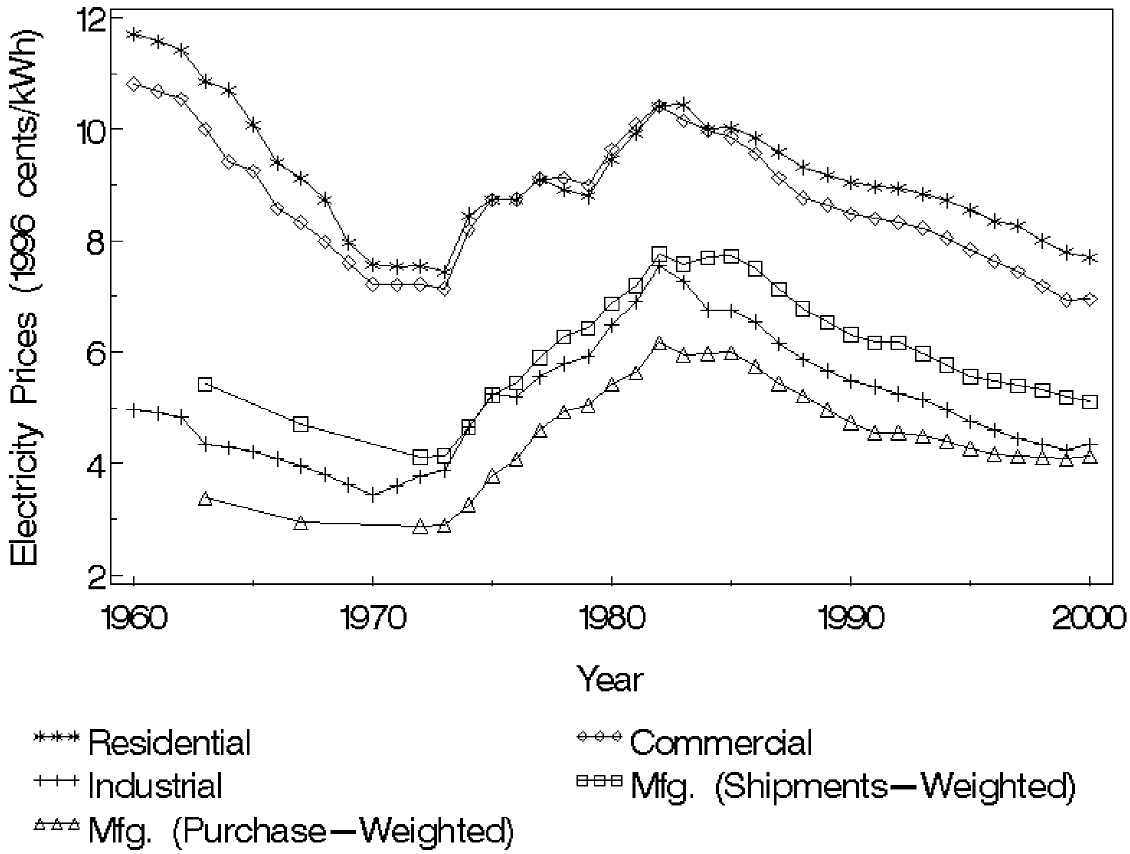
	Marginal Price (1996 ¢ / kWh)	**Marginal Cost (1996 ¢ / kWh)**	**Standard Error of Marginal Cost (1996 ¢ / kWh)**	**Difference: MP - MC (1996 ¢ / kWh)**
1963, 1967, 1973, 1974		***N* = 1,038**		
20th	4.67	4.82	0.08	-0.15
50th	3.68	3.71	0.08	-0.03
80th	3.19	3.18	0.08	0.01
1988, 1993, 1998, 1999		***N* = 1,180**		
20th	6.29	6.95	0.27	-0.65
50th	5.09	4.95	0.27	0.15
80th	4.26	4.21	0.27	0.04

Notes: See text for a description of the underlying specifications and estimation methods.



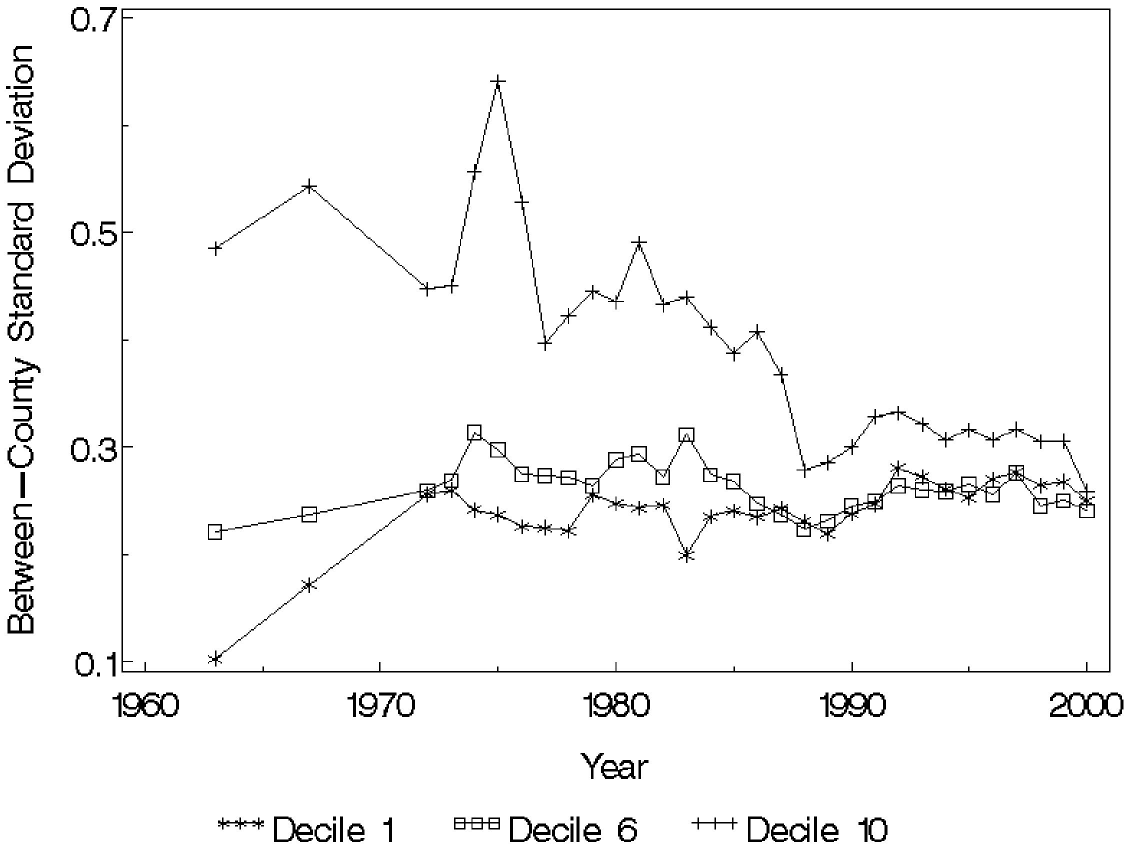
Source: Authors' calculations on PQEM data.

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.

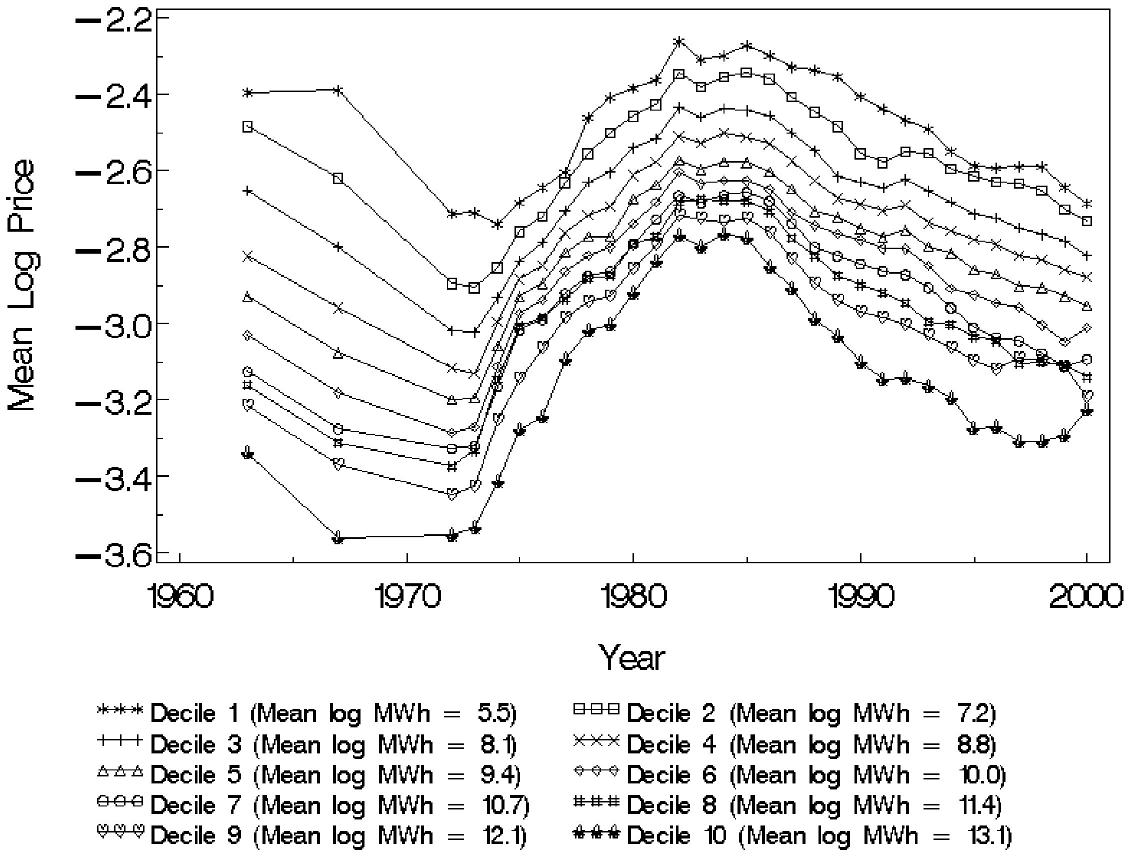
Figure 2. Real Electricity Prices by End-Use Sector, 1960-2000



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

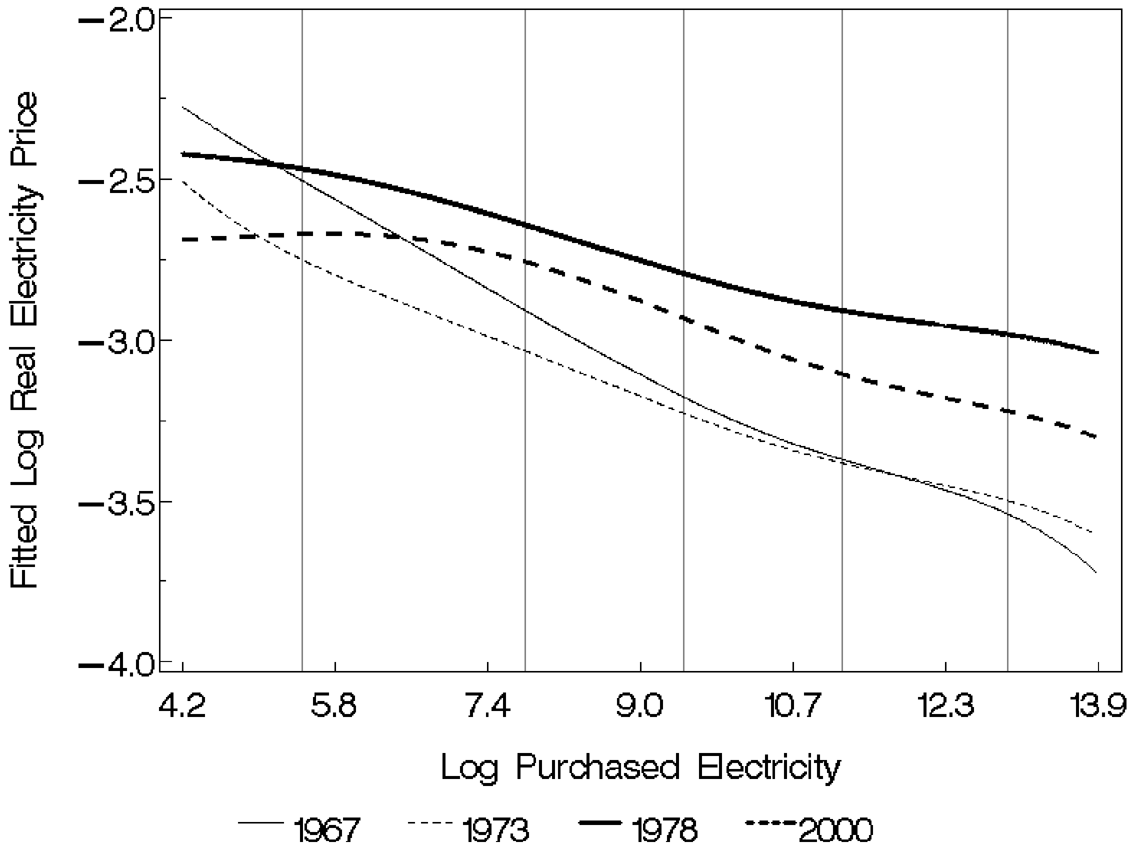
Note: The between-county standard deviations are calculated in a purchase-weighted manner using residuals from annual customer-level regressions of log price on a fifth-order polynomial in log purchases.

Figure 3. Spatial Price Dispersion by Selected Deciles of the Purchases Distribution, 1963-2000



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

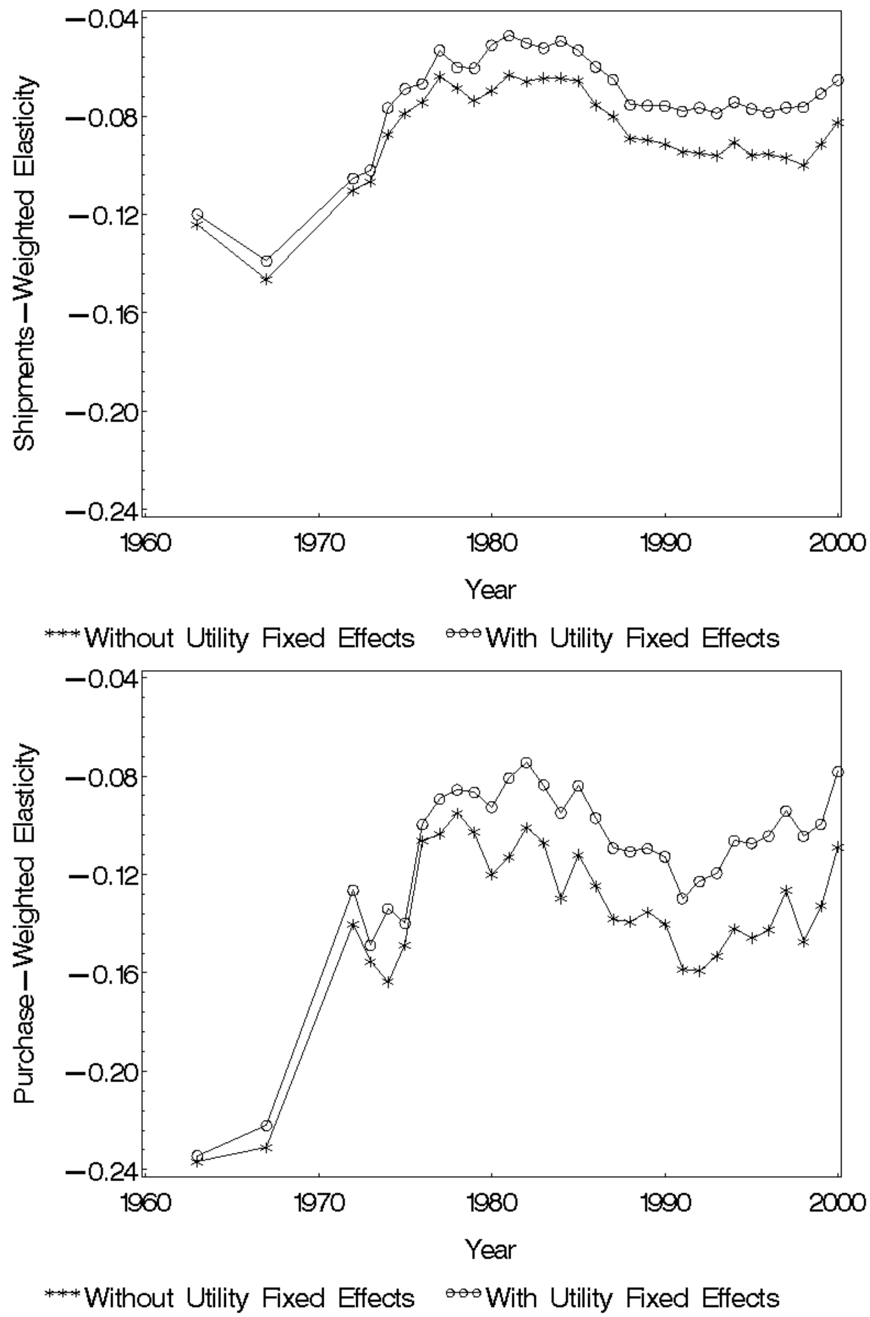
Figure 4. Mean of Log Real Electricity Prices by Purchase Deciles, 1963-2000



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

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

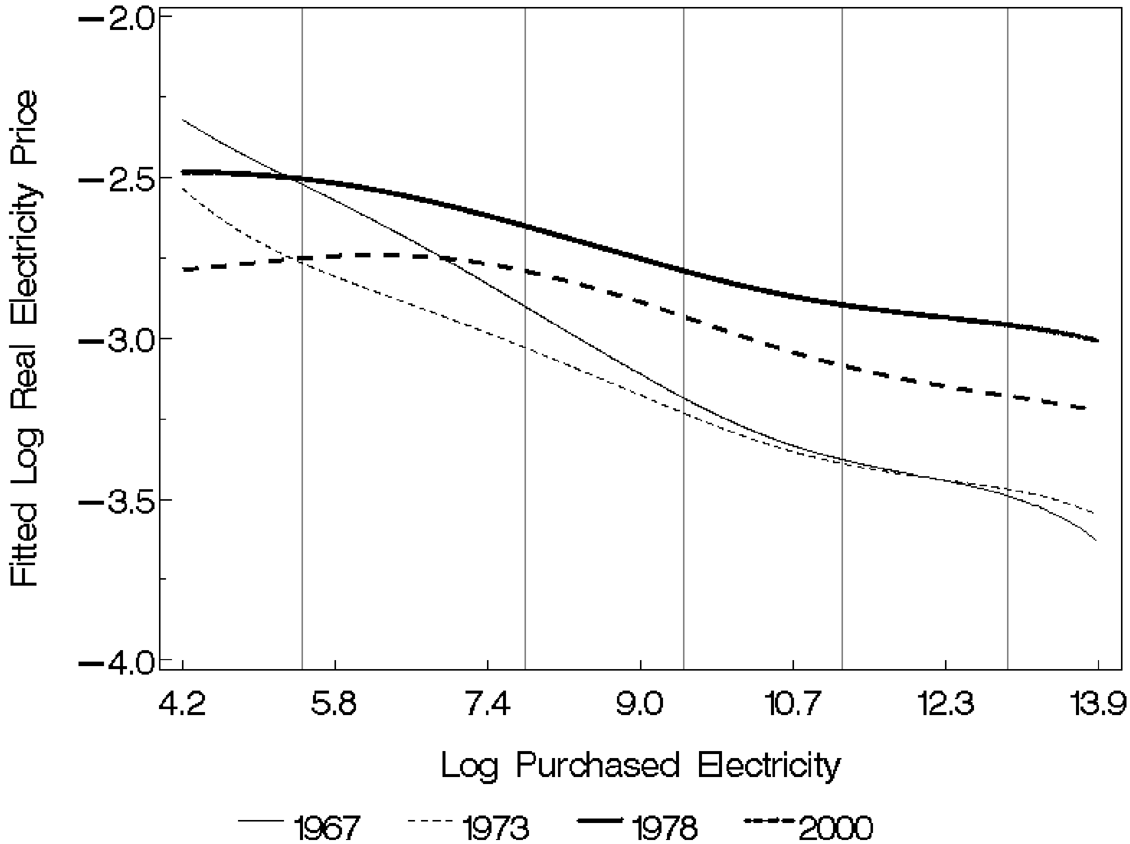
Figure 5. Log Electricity Price Fit to Fifth-Order Polynomials in Log Purchases, Selected Years



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.

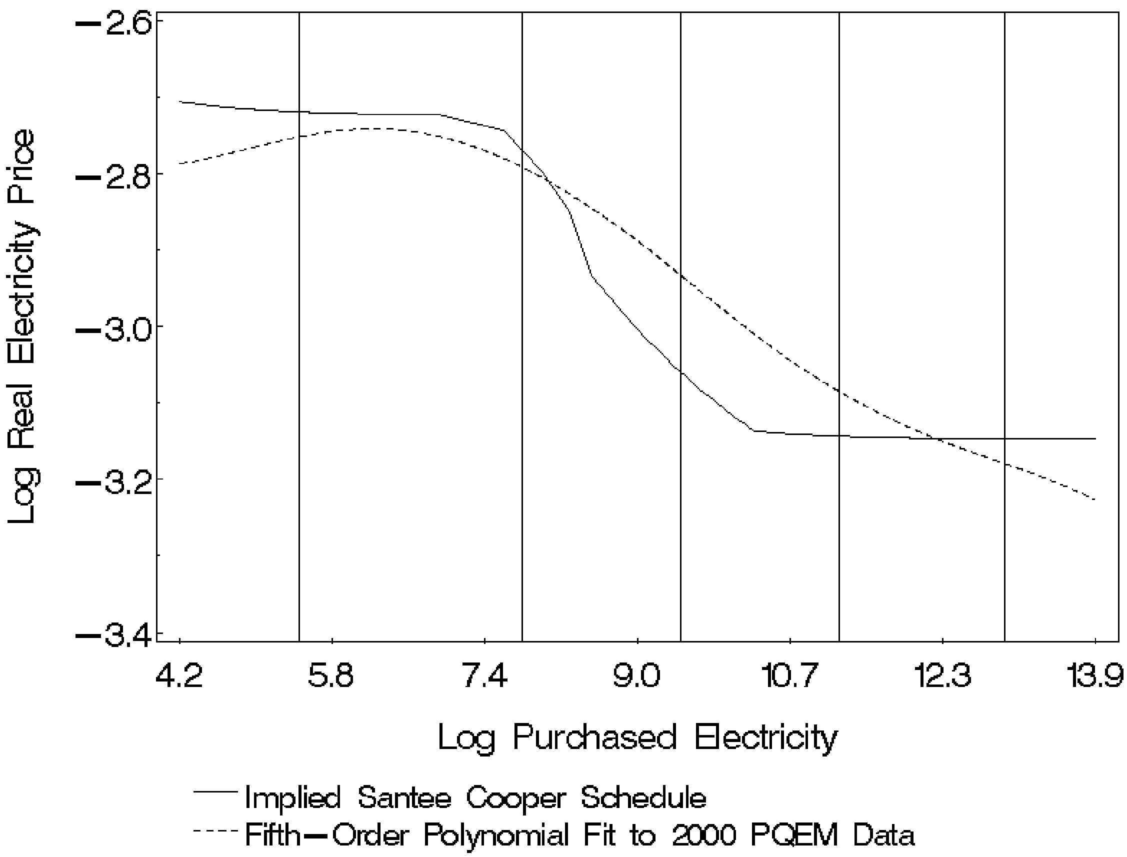
Figure 6. Average Elasticity of Price with Respect to Purchase Quantity, 1963-2000



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

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

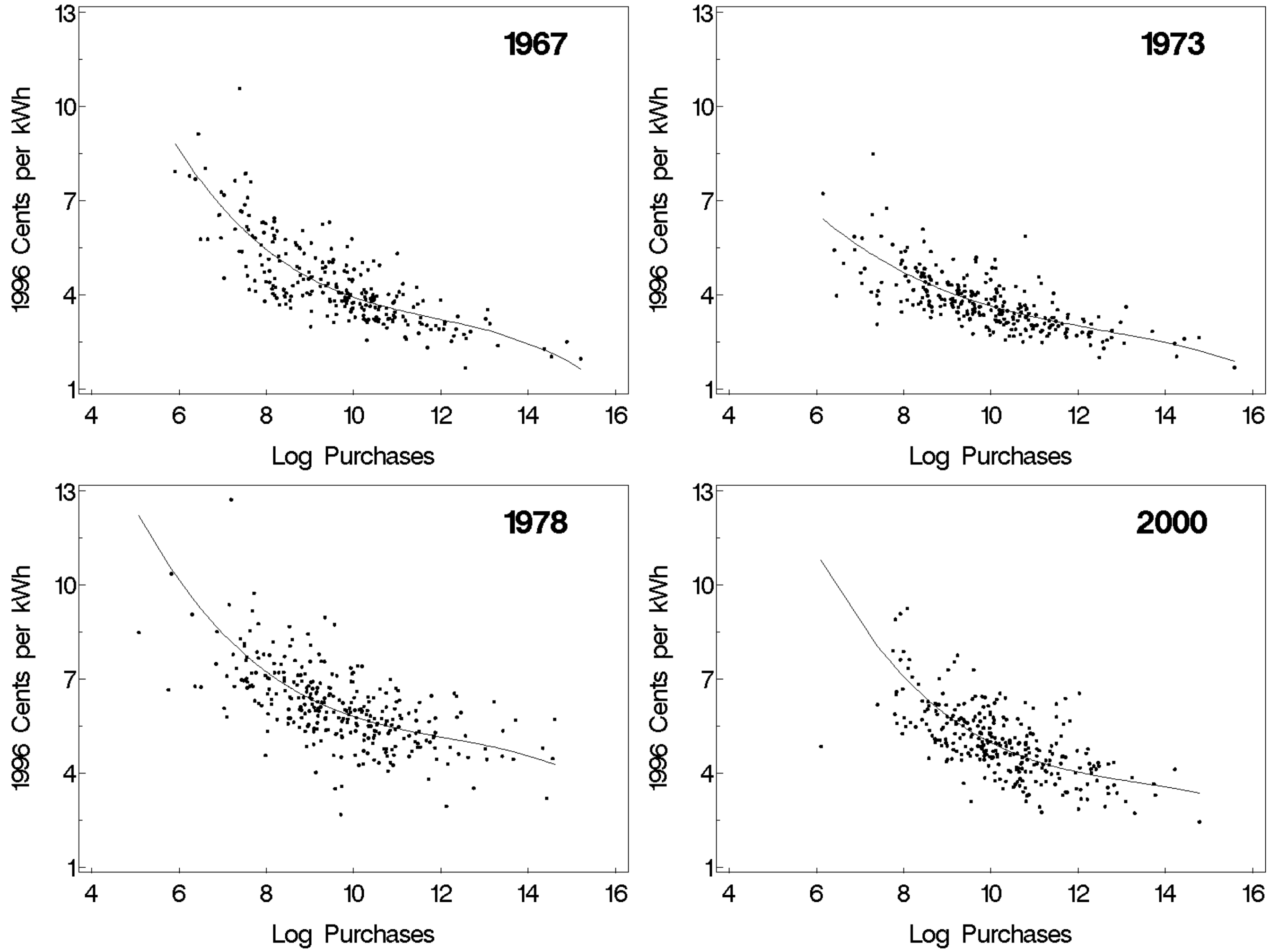
Figure 7. Log Electricity Price Fit to Fifth-Order Polynomials in Log Purchases controlling for utility fixed effects, Selected Years



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 5th, 25th, 50th, 75th, and 95th percentiles of the shipments-weighted distribution of annual purchases for 1967, 1973, 1978, and 2000.

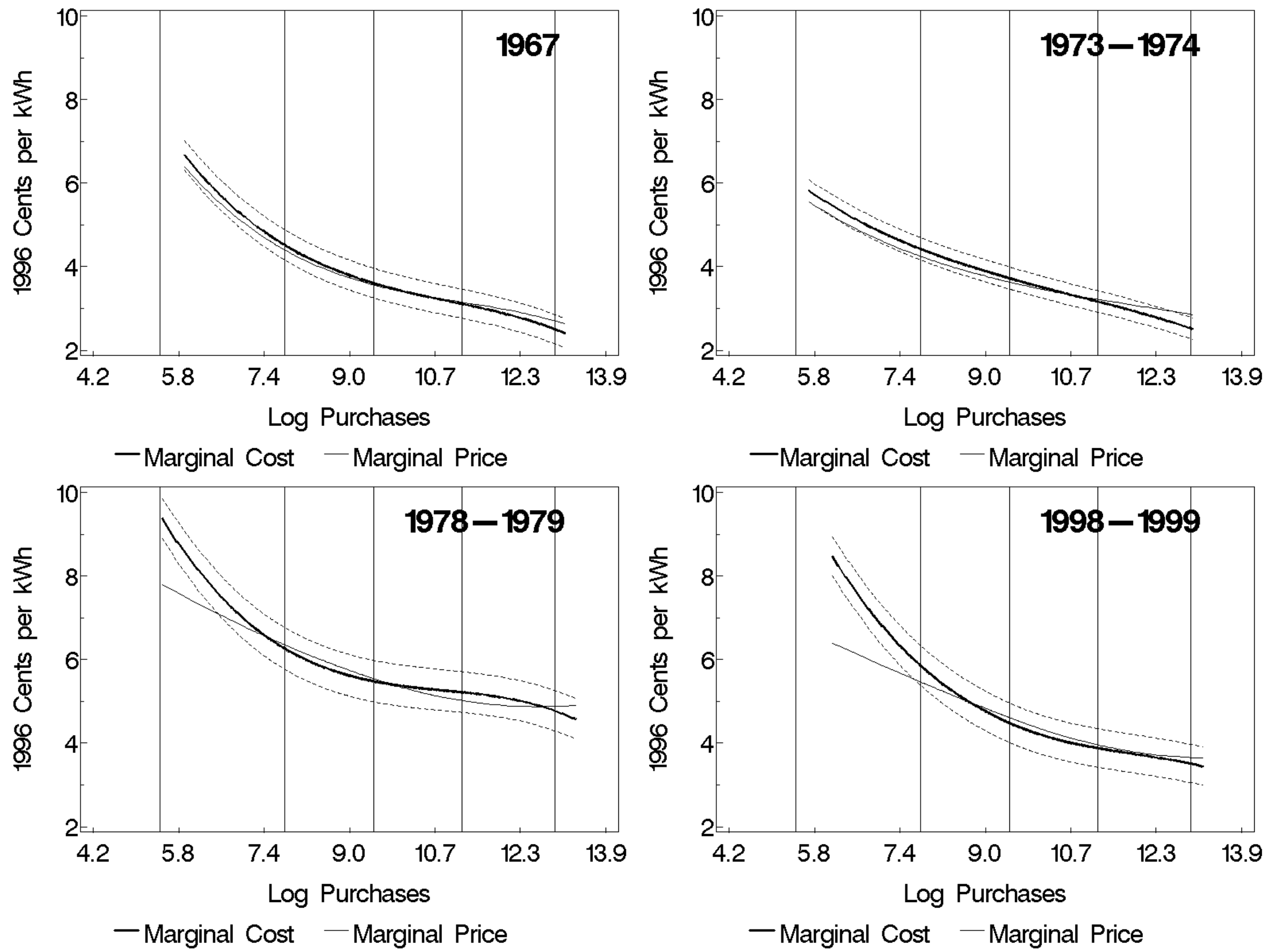
Figure 8. Comparison of Empirical and Implied Price-Quantity Schedules, 2000



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.

Figure 9. 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 5th, 25th, 50th, 75th, and 95th percentiles of the shipments-weighted distribution of annual purchases for 1967, 1973, 1978, and 2000. Dashed curves show bootstrapped (unit) standard error bands.

Figure 10. Marginal Cost and Marginal Price Schedules Compared, Selected Years