PRELIMINARY AND INCOMPLETE DRAFT

Electricity Prices at U.S. Manufacturing Plants, 1963-2000

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Abstract

We develop and exploit a rich database to study the distribution of electricity prices paid by U.S. manufacturing plants from 1963 to 2000. The between-plant standard deviation of log prices per watt-hour fell from 55% in 1967 to 44% in 1979, and price dispersion among industries fell even more. We trace this compression to the sharp erosion of quantity discounts: the elasticity of price with respect to annual purchases shrank from -15% in 1967 to -6% in 1977, later settling at levels near -9%. Price differences by purchase levels account for 75% of overall dispersion in 1963 but only 30-34% in the late 1970s.

The spatial dispersion in average electricity prices among states, counties and utility service areas is also large. Aside from the loss of huge discounts by a few dozen big purchasers, however, spatial price dispersion shows only a modest downward trend over time. Geographic differences in the mix of power sources used to generate electricity partly explain the spatial structure of retail prices and the temporary rises in spatial price dispersion after major oil price shocks. Rising real electricity prices from 1973 to 1983 led to the spatial sorting of electricity-intensive manufacturing activities to counties with cheaper electricity.

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1. Introduction

Recent developments and longstanding concerns have combined to intensify interest in the performance of the U.S. electricity sector. These include a wave of restructuring and deregulation initiatives in the 1990s, rapid growth of wholesale power markets, persistent regional disparities in retail prices, difficulties in the transition to a more competitive electricity sector, and, perhaps most spectacularly, the California electricity crisis of 2000-2001.[1] Despite these developments and concerns, we lack broad empirical studies of the prices paid by U.S. electricity consumers. As a result, 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, evaluate the impact of regulatory changes on consumers, assess theories of public utility pricing, and reach informed judgments about reform proposals.

To address these gaps, we construct a rich micro database – Prices and Quantities of Electricity in Manufacturing (PQEM) – and use it to study the distribution of electricity prices paid by U.S. manufacturing plants from 1963 to 2000.[2] The PQEM includes data on electricity expenditures, purchases (watt-hours) and other variables for more than 48,000 manufacturing plants per year, and it is linked to additional data on the utilities that supply electricity. The PQEM relies on calendar-year measures of electricity

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[1] Hirsh (1999), Borenstein (2002), DOE (2002), EIA (2002b) and Joskow (2003), 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] Historically, industrial purchasers account for a large percentage of retail electricity sales – 48 percent in 1963, the start of our sample period. That percentage declines over time, but industrial purchasers still account for 31 percent of retail sales as of 2000 (EIA, 2001). In turn, manufacturing plants account for the lion's share of electricity purchases by the industrial sector and, as we show below, average electricity prices for the manufacturing sector are similar to average prices for the industrial sector as a whole.

expenditures and purchases by plants in the Annual Survey of Manufactures (ASM). These data are available for 1963, 1967 and annually since 1972.

Figure 1 displays several measures of dispersion in the distribution of log electricity prices from 1963 to 2000.[3] The plant-level price measure is the ratio of annual expenditures on purchased electricity to annual purchases (watt-hours). We consider purchase-weighted and shipments-weighted price distributions. The former weights each plant-level observation by watt-hours of electricity input, and the latter weights by output, as measured by shipments. These weighting methods mirror the use of input-weighted and output-weighted productivity distributions in studies that quantify between-plant and within-plant components of productivity growth.[4]

As seen in Figure 1, there is remarkable heterogeneity in retail electricity prices. The purchase-weighted between-plant standard deviation exceeds 40% in all years and reaches 55% in some years. For perspective, it is helpful to compare this measure of electricity price dispersion to analogous measures of wage dispersion. On an hours-weighted basis, the standard deviation of log hourly wages among manufacturing workers ranges from 44% to 54% between 1975 and 1989, and the standard deviation of log hourly production worker wages among manufacturing plants ranges from 37% to 43% between 1975 and 1993.[5] In other words, the dispersion in electricity prices among

[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 focus on log prices in much of the paper, but we also consider prices measured in natural units.

[4] Examples include Foster et al. (2001) and van Biesebroeck (2004).

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

manufacturing plants is as great as wage dispersion among manufacturing workers and greater than wage dispersion among plants.

Figure 1 also reveals a great compression in the log price distribution through the late 1970s. The between-plant standard deviation fell from 55% in 1967 to 44% in 1979 on a purchase-weighted basis and from 47% to 35% on a shipments-weighted basis. Over the same time frame, the 90-10 price differential shrank by about 37 log points under both weighting methods. The 90-10 differential later widened but did not return to the peaks of the 1960s. Industry price differentials show an equal or greater compression through the late 1970s, depending on weighting method, and a modest recovery after the early 1980s. To the best of our knowledge, we are the first to quantify the extent of electricity price dispersion for a major end-user sector and the first to document the great compression episode that played out during the first two decades of our sample period.

We show below that the great compression episode reflects a sharp erosion of quantity discounts. The average elasticity of price with respect to annual purchases declined sharply in magnitude from –15% in 1967 to –6% in the late 1970s. Quantity discounts recovered somewhat after the mid 1980s, and the price-quantity elasticity settled near –9%. Because the range of electricity purchase levels is enormous, these elasticities translate into very large discounts.[6] Prices for the few dozen biggest purchasers, for example, were two-thirds below the median price in the 1960s. Purchase levels account for 75% of overall price dispersion in 1963 but only 30% by 1978.

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

[6] The 90th quantile of the shipments-weighted distribution of purchases exceeds the 10th by a factor of nearly 400, and the 99th quantile exceeds the 1st by a factor of 10,000. The corresponding quantile ratios for the purchase-weighted distribution are *much* larger.

Quantity discounts in the form of declining-block tariffs are a well-known feature of retail electricity pricing and a sometimes contentious matter in ratemaking proceedings and legislative hearings.[7] They are also the subject 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). The marginal cost of supplying electrical power tends to decline with purchase levels for reasons that we discuss, so that an efficient two-part tariff or other marginal-cost pricing scheme will exhibit quantity discounts. Under reasonable assumptions about demand elasticities, Ramsey pricing by a revenue-constrained public utility also leads to quantity discounts. In practice, however, the approach to rate setting by electric utilities and their regulators, as well as the resulting tariff schedules, do not seem well designed to achieve efficient pricing (Brown and Sibley, 1986).

We also investigate the spatial distribution of electricity prices among states, counties and utilities. In part, we are motivated by the question of whether growth in wholesale power markets caused spatial price differentials to diminish. It turns out that measured trends in spatial price dispersion are highly sensitive to how we weight the plant-level observations. On a shipments-weighted basis, spatial price dispersion across counties, for example, exhibits an upward trend until the early 1990s. On a purchase-weighted basis, price dispersion across counties shows a strong downward trend throughout our sample period.

[7] Cudahy and Malko (1976) discuss quantity discounts and other aspect 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.

The sensitivity of spatial dispersion trends to weighting method is a consequence of changing quantity discounts and the highly skewed distribution of electricity purchases. In fact, when we restrict the sample to exclude the roughly 20-50 plants with annual purchases in excess of 1,000 gigawatt-hours, the purchase-weighted dispersion of electricity prices across counties shows no downward trend until the early 1980s, and a much more modest downward trend since the early 1980s. Other prominent features of the data, such as the magnitude of industry price differentials and their movements over time, also reflect the size and evolution of quantity discounts.

We also show that geographic differences in the mix of power sources used to generate electricity partly explain the spatial structure of prices and the temporary rises in spatial price dispersion after major oil price shocks. Finally, we provide evidence that rising real electricity prices after 1973 led to some spatial sorting, whereby electricity-intensive manufacturing activities located in areas with cheaper electricity.

The paper proceeds as follows. Section 2 provides background on the electricity sector, selected economic and regulatory developments, and changes over time in the real cost of electricity. Section 3 describes the PQEM database. Section 4 decomposes the variance of electricity prices in terms of industries, states, counties, electricity purchase levels, and the utilities that supply electricity. Section 5 examines electricity price-quantity schedules and traces out their role in the great price compression episode. Section 6 considers the spatial structure of electricity prices, and Section 7 concludes.

2. Background and Context

From its inception in the 1880s until the mid 1960s, the electric power industry enjoyed a "golden era" in which generating technology improved rapidly, capacity was plentiful, and electricity prices fell.[8] Utilities offered promotional block pricing whereby the price per kilowatt-hour (kWh) declined with purchase amounts. Stimulated by falling real prices, quantity discounts, and new electrical appliances and machinery, electricity consumption grew rapidly after World War II (Hirsh, 1989, Chapter 4). This golden era drew to a close by the late 1960s as unforeseen technological and metallurgical barriers hampered progress in the creation of better electric generators.[9]

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

Several regulatory developments added to cost pressures and tightened capacity constraints. Concerns about air and water pollution from conventional power plants and about safety at nuclear plants led to several pieces of legislation in the late 1960s and 1970s that raised costs and hampered the operation and development of the electricity industry.[10] The National Environmental Policy Act of 1969 required utilities to prepare and defend environmental impact statements for new generator sites. The Clean Air Act

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

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

of 1970 restricted air pollutants at electricity-generating plants and encouraged utilities to switch from coal to cleaner burning oil or natural gas. The Federal Water Pollution Control Act of 1972 limited waste discharge, and the Resource Conservation and Recovery Act of 1976 set forth standards for utility waste products. The Energy Supply and Environmental Coordination Act of 1974 authorized the federal government to prohibit purchases of natural gas and petroleum by utilities. The Clean Air Act Amendments of 1977 imposed more stringent restrictions on emissions from electricity-generating plants.

In 1978, several major pieces of legislation passed as part of President Carter's National Energy Plan. The plan included the gradual removal of price controls on oil and natural gas, restrictions on the use of oil and natural gas by electricity generating plants, and rate reform provisions for electric utilities. The Public Utilities Regulatory Policies Act (PURPA) of 1978 had the biggest impact on the electricity sector.[11] Its rate-reform provisions were hotly contested in Congress (Hirsh, 1999) but, in their final form, required that state regulatory authorities merely "consider" various reforms that included an end to promotional pricing structures. In addition, PURPA Section 210 required utilities to buy from and sell power to "qualifying facilities." The goal was to draw non-utilities, such as cogeneration plants and renewable resource plants, into the electric power market. In this respect, PURPA and later legislation had a major impact. By 1999, non-utilities owned 19.8 percent of the electric generating capacity in the U.S. (EIA, 2000a, p.1).

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[10] See Appendix A of EIA (2000b) for a detailed description of legislation summarized in this paragraph.
[11] See Joskow (1989, pages 127-128), White (1996, pages 206-207), and Chapters 4 and 5 in Hirsh (1999). Hirsh (1999) and Gordon (1982) provide extensive discussion of PURPA.

The effect of these technological, economic and regulatory developments on retail electricity prices can be seen in Figure 2, which plots the average real price per kilowatt-hour (kWh) for major end-user sectors.[12] Real electricity prices ceased falling in 1970, and they began to rise after 1973, partly because of sharply higher costs for the fossil fuels that powered many of the generating plants. Real electricity prices continued to rise for about ten years, before returning to a pattern of steady declines.

Wholesale trade in electricity markets expanded rapidly in the 1990s, stimulated by legislative and regulatory policy changes. The Energy Policy Act of 1992 (EPACT) sought to promote greater competition and participation in wholesale markets and to unbundle the sale of electrical power from transmission and distribution services (White, 1996 and Joskow, 1997). PURPA Section 210, FERC Orders 888 and 889 (issued in 1996) and various state-level actions during the 1990s also stimulated growth in the wholesale trade of electricity. These legislative and regulatory actions helped to create a new class of power producers (non-utility qualifying facilities) with secure access to transmission facilities and exemption from many of the traditional restrictions on public utilities. Sales of electricity for resale rose from 41% of generated power in 1991 to 61% in 2000 (EIA, 2003a, Tables ES and 6.2).

In recent years, several states have undertaken efforts, not always successful, to introduce greater retail competition in the electricity sector. According to Joskow (2003, page 2), the "first retail competition programs began operating in Massachusetts, Rhode

[12] 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

Island and California in early 1998 and spread to about a dozen states by the end of 2000." These developments on the retail side of the electricity sector come at the tail end of the period covered by our data.

3. The PQEM Database

The PQEM database derives principally from the U.S. Census Bureau's Annual Survey of Manufactures (ASM) and various data files provided by the Energy Information Administration (EIA). We draw our data on electricity prices and quantities and other variables for individual manufacturing plants from ASM micro files for 1963, 1967, and 1972-2000. The ASM is a series of nationally representative, five-year panels that are refreshed by births as a panel ages. Large manufacturing plants with at least 250 employees are sampled with certainty, and smaller plants with at least 5 employees are sampled randomly with probabilities that increase in the number of employees.[13] ASM plants account for about one-sixth of all manufacturing plants and about three-quarters of manufacturing employment. All of 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 other location information that we use to assign manufacturing plants to electricity suppliers. As described in a companion paper (Davis et al., 2004), we

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BEA implicit price deflator for GDP (1996 = 100). In the EIA data, the industrial sector encompasses manufacturing, mining, construction and agriculture.

[13] 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.

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.

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

We also exploit publicly available information on the identity of those plants that purchase electricity directly from the six largest public power authorities.[15] Direct purchasers from public power authorities typically consume large quantities of electricity, and they often accept high-voltage power, operate their own transformers, and obtain

[14] 449 counties are served by a single utility, 770 are served by 2 utilities, 786 are served by 3 utilities, 537 are served by 4 utilities, 458 are served by 5-7 utilities, and the remaining 29 counties are served by 8-12 utilities. To the best of our knowledge, data on the list of counties served by each electric utility are not available prior to 1999. Hence, we apply each utility's county list for 2000 to all years.

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

electrical 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.

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

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

Table 1 reports selected characteristics of the PQEM. The database contains more than 1.8 million plant-level observations over the period from 1963 to 2000. There are 3,029 counties with manufacturing plants and 349 utilities, counting multi-state utilities once for each state in which they sell to industrial customers. The table shows that electricity purchases and cost shares vary enormously. For example, the 90th quantile of

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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).

the purchases distribution is 381 times the 10th quantile on a shipments-weighted basis and 741 times on a purchase-weighted basis. The median ratio of electricity costs to labor costs is 4.7% on a shipments-weighted basis and 18.4% on a purchase-weighted basis. While electricity costs are a modest percentage of labor costs for most plants, those for which electricity costs exceed 65% (205%) of labor costs account for one-fourth (one-tenth) of all electricity purchases. In other words, a large fraction of electricity is purchased by plants for which electricity is a primary or major cost of production.

4. Electricity Price Dispersion Between and Within Groups of Plants

We decompose the variance of electricity prices into between-group and within-group components using indicators of industry, geography, electricity supplier, and purchase amounts. Indexing plants by *e* and groups by *l*, the variance can be expressed as

$$\begin{aligned} V &= \sum_e s_e \left(lp_e - \overline{lp}\right)^2 = \sum_l \sum_{e \in l} s_e \left(lp_e - \overline{lp}\right)^2 \\ V &= \left(\sum_l s_l \sum_e s_e \left(lp_e - \overline{lp_l}\right)^2 \right) + \left(\sum_l s_l \left(\overline{lp_l} - \overline{lp}\right)^2 \right) \qquad (1) \\ V &= \quad V_{wl} + V_{bl} \end{aligned}$$

where lp_e is the log price of electricity for plant *e*, s_e is the weight for plant *e*, $\overline{lp}$ is the overall weighted mean log price, $\overline{lp_l}$ is the weighted mean log price for group *l*, $s_l = \sum_{e \in l} s_e$ is the sum of weights for plants in group *l*, V_{wl} is the average within-group variance, and V_{bl} is the between-group variance. Table 2 reports the shipments-weighted version of (1) for selected years, with s_e set to the product of the plant's ASM sample weight and its shipments value. Table 2 also reports the between-group standard deviation of log prices, and Table 3 reports analogous purchase-weighted statistics.

According to Table 2, the 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. The purchase-weighted standard deviation of log prices (Table 3) also fell sharply – from 55% in 1967 to 43% in 1977 and then further in the 1990s to stand at 38% in 2000. These are the same patterns highlighted by Figure 1.

Tables 2 and 3 contain several other noteworthy results. First, the between-industry dispersion of electricity prices fell rapidly through 1982 and, on a purchase-weighted basis, to even lower levels in the 1990s. All told, the purchase-weighted dispersion of industry prices fell by almost half over the past four decades. Industry accounts for 71% of overall price dispersion in 1963 but only 38% in 2000.

Second, county effects account for a high percentage of overall price dispersion as well, never less than 65% on a purchase-weighted basis. Broader geographic groupings also account for much of the price dispersion among plants. For example, the 349 utilities account for more than half of overall price dispersion on a purchase-weighted basis, about 80-90 percent as much as the roughly 3,000 counties.

Third, spatial price dispersion declined sharply over time on a purchase-weighted basis, but it rose on a shipments-weighted basis. Focusing on counties, the purchase-weighted standard deviation fell by nearly one-third from 1963 to 2000, while the analogous shipments-weighted measure rose by one-fifth. We highlight this contrast in Figure 3, which displays the between-county standard deviation of log prices for both weighting methods. Figure 3 also plots the purchase-weighted between-county standard deviation for a restricted sample that excludes plants with purchases of more than 965 gigawatt-hours during the year.[16] Very few plants, ranging in number from 16-56 per year, meet this exclusion criterion. These plants account for roughly one percent of manufacturing employment and two percent of shipments, but they account for 13-23% of all electricity purchases by the manufacturing sector.

The restricted-sample measure in Figure 3 shows that the entire decline in purchase-weighted price dispersion through the early 1980s, and most of the decline thereafter, involves developments in the upper tail of the purchases distribution. And to a considerable extent, the discrepancy between the purchase-weighted and shipments-weighted measures of spatial price dispersion also reflects developments in the upper tail. In fact, from 1989 to 2000, the purchase-weighted spatial dispersion measure for the restricted sample is nearly identical to the shipments-weighted measure in the full sample. We revisit this matter below when we consider the impact of quantity discounts on the distribution of electricity prices and its evolution over time.

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

Finally, the bottom panels in Tables 2 and 3 show that purchase level and electricity supplier jointly account for a very high percentage of overall price dispersion throughout the past four decades. Groups defined by utility crossed with purchase deciles account for 55-74% of price dispersion on a shipments-weighted basis and 70-89% on a

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

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

We summarize the empirical results to this point in three statements. One, there is much heterogeneity among manufacturing plants in the 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 industry, location and purchase amounts account for most of the variation in electricity prices.

5. Electricity Price-Quantity Schedules *(This section incomplete)*

We turn now to a detailed investigation of how the plant-level price per kWh varies with annual kilowatt-hours of consumption. Among other things, we will show that most of the cross-sectional price variation in Tables 2 and 3, as well as the changes in the cross-sectional distribution over time, can be understood as a consequence of quantity discounts and their evolution. We first review the structure of electricity tariffs for industrial customers and identify several potential reasons why electricity prices and supply costs decline with purchase levels.

5.1 Electricity tariff schedules

Electricity tariffs for industrial customers usually include separate energy and "demand" charges.[17] The energy charge depends on total kilowatt-hours of consumption during the billing period, while the demand charge depends on the highest consumption over 15- or 30-minute intervals within the billing period or other time period. Roughly speaking, the demand charge reflects the customer's maximal requirements for generation, transmission and transformer services. Traditionally, electric utilities have offered declining-block rate schedules, whereby both the marginal price per kWh of energy and the marginal price per kilowatt of demand decline as step functions. For bigger purchasers, in particular, electricity tariffs can also depend on other factors such as voltage level and willingness to accept interruptible or curtailable power. Differential rates by time of year and time of day and other applications of peak-load pricing principles were rare in the early part of our sample, but they began to spread after key regulatory decisions in the mid 1970s (ELR, 1975, and Cudahy and Malko, 1976). A move toward more finely differentiated tariff schedules for industrial customers continued through at least the late 1980s (Wilson, 1993, pages 36-38).

The PQEM database reports the average price kWh paid by electricity consumers, but it does not report the underlying electricity tariff schedules. In this respect, the PQEM is analogous to household and firm-level data sets that report average hourly or annual wages but not the underlying compensation schedules. To be sure, the lack of data on the underlying tariff schedules is a limitation, but it does not preclude an informative analysis. There is a vast body of research on wage structure and labor demand that fruitfully exploits data on average wage rates for individual workers and employers.

5.2 Cost and Demand Factors that Influence Electricity Price-Quantity Schedules

The supply of electricity to end-users requires generating facilities, transmission lines, transformers and metering devices. Marginal generating costs depend on several factors including power source and generator efficiency. Base-load generators have relatively low marginal costs, whereas intermediate and peak-load generators have higher marginal costs. Electrical energy dissipates as heat energy during transmission and in the process of transforming voltage levels. One way to lower energy losses and transmission costs is to rely on high-voltage power lines that involve less dissipation as heat energy.

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[17] See Cowern (2001) for a clear and concise introduction to electricity tariffs for industrial customers.

However, high voltage levels are dangerous, so transformer stations near the final delivery point are typically used to step down voltage levels for end users.

Supply costs per kWh of electricity tend to be lower for larger industrial customers. Several factors play a role in this respect. (a) Large electricity users are more likely to locate near power generators to minimize transmission losses. (b) High-voltage transmission lines can lead all the way to the customer's "doorstep", further reducing transmission costs. (c) A large power consumer is more likely to operate equipment at high voltage levels, circumventing or reducing the need for step-down transformers and complex distribution networks. (d) Plants that use large amounts of power may operate and maintain their own step-down transformers in any event, relieving the utility of this task and associated costs. (e) Larger electricity customers have stronger incentives to manage load factors and respond to peak-load pricing schedules so as to reducesupply costs. In addition, some large electricity users may accept interruptible power provisions in exchange for lower prices. In short, cost factors alone lead us to anticipate quantity discounts for electricity prices paid by manufacturing plants.

In addition, demand factors also lead to quantity discounts under plausible conditions. Consider a utility that prices electricity so as to maximize consumer surplus subject to the constraint that its revenues equal its costs. As shown by Brown and Sibley (1986) and Wilson (1993), among others, the optimal nonuniform pricing schedule 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 qth unit of electricity, $C(q;Q)$ is the marginal cost of the qth unit when the total quantity demanded is $Q,, \eta\left[M(q),q\right]$ 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.[18]

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

5.3 The Santee Cooper Tariff

The Santee Cooper electric utility provides detailed information about its commercial and industrial tariffs.[19] The Santee Cooper tariff schedules contain the ffour basic charges: a monthly customer charge, monthly demand charges, monthly energy

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[18] It is worth pointing out that the cost-recovery constraint does not preclude marginal cost pricing, even for a utility with increasing returns over the relevant range. Consider a two-part tariff with a fixed access fee for each customer and a 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 marginal cost pricing. In practice, demand charges and other access fees under U.S. electricity tariffs do not fully cover fixed costs, so that some portion of the fixed costs must be recovered by setting marginal prices above marginal costs. The Ramsey pricing rule (2) minimizes the allocative distortions induced by pricing above marginal cost.

[19] Santee Cooper is also known as the South Carolina Public Service Authority. Among utilities with positive industrial revenue, Santee Cooper is close to average size with industrial sales of $238 million in 2000. The Santee Cooper price schedules discussed here have been in use since 1996. They are available for download at http://www.santeecooper.com/.

charges, and, if applicable, a monthly facilities charge. The monthly customer charge and portions of the monthly demand charges are non-trivial and are fixed depending on the type of agreement between the customer and Santee Cooper. For example, in the industrial large light and power agreement, the monthly customer charge is $1200 per month for each delivery point.[20] Additionally, the customer must pay the monthly demand charge for the first 300 kW of electricity demand each month regardless of whether or not they reach the 300 kW demand level. The monthly energy charges are based on the number of kWh consumed, a fuel cost adjustment, and possibly other adjustments. The monthly facilities charge only applies if Santee Cooper constructs special facilities for the customer, in which case the customer pays 1.4% of the original installation cost per month.

The Santee Cooper tariff schedules exhibit several types of discounts related to the factors we discussed above. For example, Santee Cooper offers a discount of approximately 36% from their general large user rates for accepting interruptible power. Additionally, a discount of approximately 5% is offered to customers who transform their own power. Other features include a discount of roughly 85% on “economy power” for very large electricity purchasers and a discount of approximately 80% under certain conditions for electricity during off-peak hours. Economy power is power that Santee Cooper has determined is not required by other customers. This type of power is not always available.

[20] Santee Cooper considers each location and/or voltage level of electricity delivery a separate “delivery point”.

5.4 Empirical Price-Quantity Schedules

We now consider empirical evidence on electricity price-quantity schedules for manufacturing plants and changes in these schedules over time. Figure 4 shows the mean log real price of electricity by purchase decile from 1963 to 2000. As of 1967, the mean price for plants in the lowest purchase decile was over 100 log points higher than in the highest decile. Smaller price differentials are apparent throughout the entire distribution of electricity purchases. Purchase-level price differentials shrink dramatically from 1967 through the first half of the 1970s. By 1978, the year when PURPA was enacted, the dramatic erosion in quantity discounts was already complete. More modest quantity discounts persisted after 1978 and throughout the period until 2000. The average price gap between the biggest and smallest electricity users remains large after 1978, amounting to about 50 log points in 2000.

We also compare the Santee Cooper price schedules to the PQEM data for the year 2000. We use the information provided in the Santee Cooper price schedules to estimate a lower envelope price schedule for the range of log purchased electricity values in the PQEM. The schedule is shown in the upper panel of Figure 5.[21] This price schedule does not include potentially large discounts for accepting interruptible power, accepting power at high voltage, etc. The upper panel of Figure 5 also shows a fifth-order polynomial fit with utility fixed effects of PQEM log real electricity prices on log purchased electricity for the year 2000. Comparing the two curves in the upper panel of

[21] The lower envelope price schedule is based on the following four Santee Cooper price schedules: commercial general service, commercial medium general service, commercial large general service, and industrial large light and power. Manufacturing plants purchasing relatively small quantities of electricity likely qualify for one of the commercial price schedules rather than the industrial price schedule. Since the PQEM does not contain information on monthly demand, we estimate monthly demand as two times the monthly consumption in MWh.

Figure 5, we see that the levels are very close. The differences in the two curves reflect that the 2000 fit line represents the average utility and that the Santee Cooper price schedule does not include large discounts available to big purchasers. The lower panel of Figure 5 shows shipments- and purchase-weighted kernel density estimates of the log purchased electricity distribution. We see the bulk of PQEM plants in 2000 have log purchased electricity values between 8 and 12, which correspond to purchased electricity quantities between roughly 3,000 and 163,000 MWh.

Figures 6a and 6b provide a more detailed look at the price-quantity schedules for selected years. Figure 6a plots the mean log price by purchase centile, and Figure 6b plots the fitted relationship between price and amount purchased based on plant-level regressions of log price on utility fixed effects and a fifth-order polynomial in log purchases. The panels show a flattening of the price-quantity schedule through 1978 and little change in the shape of the schedule after 1978. Figure 6b also suggests that the price-quantity schedule can be roughly approximated as a log linear relationship, a fact that we exploit below.

It is worth remarking that what appear to be quantity discounts in Figure 6a could, in fact, be spatial dispersion in disguise. If manufacturing plants that purchase larger amounts of electricity are more likely to locate in areas served by utilities with relatively inexpensive power, then we can find a negative relationship between electricity price and purchase level even if all utilities offer flat price-quantity schedules. More generally, any tendency by larger electricity users to buy power from utilities with lower prices contributes to a negative price-quantity relationship. We refer to this phenomenon as “spatial sorting”.

Figure 7 displays the time series of slope coefficients from cross-sectional plant-level regressions of log electricity prices on log electricity purchases. In order to distinguish between spatial sorting and true quantity discounts at the utility level, one regression specification includes controls for utility and one does not. Figure 7 confirms the dramatic flattening of price-quantity schedules between 1963 and the late 1970s, and it conveniently summarizes the size of the quantity discount by year. The elasticity of price with respect to annual purchases stood at –13.3% in 1963, fell to about –10.8% in 1972 and diminished further to about –5.4% by 1977.

Figure 7 also shows that spatial sorting is a small part of the explanation for the negative relationship between price and quantity. Prior to the mid 1970s, the slope coefficients are virtually unaffected by the inclusion of utility fixed effects, indicating that spatial sorting played no role in the negative price-quantity relationship. Starting in the mid-1970s, there is evidence of systematic spatial sorting of larger electricity users to areas served by utilities with lower electricity prices. But even after 1975 the spatial sorting effect is modest, accounting for only about 1 to 1.5 percentage points of an elasticity that fluctuates in the range of –5% to –10%.

The within-utility elasticity of price with respect to annual purchases reaches its smallest value of –4.9% in 1981 and becomes gradually larger after the early 1980s. In the years after 1985, the within-utility elasticity of price with respect to purchases is always larger in magnitude than its value in 1977, the year prior to PURPA. This evidence reinforces our view that the rate-reform provisions in PURPA had little impact on electricity price-quantity schedules – at least for manufacturing customers.

6. The Spatial Structure of Electricity Prices *(This section rough and incomplete)*

The spatial structure of prices has changed over time. To depict some of these changes, Figure 8 displays average log price deviations from the U.S. mean for selected states. Prices in California were modestly above the national average in the 1960s and early 1970s, but then rose steadily to reach a level of over 50 log points above the national average in the 1990s. Many states in the Southwest, Mountain and Midwest regions have experienced declining relative prices in recent decades. For example, relative prices in Illinois and Michigan were about 30 log points above the national average in the 1960s but fell to just above the national mean by 2000. For many states on the east coast, relative electricity prices have remained high throughout the past four decades. Washington and Idaho, two states that rely heavily on hydropower, show low relative prices throughout the past four decades but also much volatility.[22] In particular, both states experienced abrupt drops in the relative price of electricity during the mid 1970s, followed by a long period of rising relative prices. This pattern indicates that, in response to the general rise of energy costs after 1973, electricity prices responded with a considerable lag in states that did not rely much on fossil fuels for power generation.

Figures 9 and 10 provide more systematic evidence about mobility over time within the spatial price distribution, and at a finer geographic level. These figures display scatter plots and linear regression fits for county and utility fixed effects across pairs of years.[23] The scatter plots and regression fits show considerable persistence in the spatial

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[22] Washington and Idaho generated 86.7% and 99.9%, respectively, of their electricity from hydropower in 1973. In contrast, Connecticut and Massachusetts generated 79.2% and 83.4%, respectively, of their electricity from oil and natural gas powered generating plants in 1973. We calculated these figures from EIA (2003b).

[23] For any given year, we computed county fixed effects as deviations of the county mean log price from the national mean log price. We calculated utility fixed effects in an analogous manner. In the scatter plots and in fitting the regression lines, we omitted counties and utilities that did not meet disclosure

price structure over five-year intervals. R-squared values range from .55 to .80 for the county-level regressions and from .67 to .88 for the utility-level regressions. Slope coefficients from the utility-level regressions are high, ranging from .77 to .99.

Two other aspects of Figures 9 and 10 strike us as noteworthy. First, both figures show the lowest R-squared values for the 1972-1977 interval, which encompasses the first oil price shock and a dramatic rise in the real cost of fossil fuels (Figure 11). The R-squared values are also relatively low for the 1977-1982 interval, during which the real cost of oil and natural gas, but not coal, continued to rise sharply. These results confirm the more impressionistic evidence in Figure 8 that rising fossil fuel prices in the 1970s and early 1980s disturbed the spatial structure of electricity prices.

Second, the 1990s and the latter part of the 1980s show greater stability in the spatial price structure than earlier decades. Moreover, the regression slopes fitted to these intervals are by no means on the low side, as one might expect if increasing regional or national integration of electricity markets caused spatial price differentials to revert toward the mean. These findings suggest that the rapid growth in wholesale electricity trade since the mid 1980s and the vigorous federal and state efforts to promote wholesale electricity markets have not led to a sharp compression of spatial price differentials. It is certainly possible that a narrowly focused geographic analysis would uncover evidence of spatial price convergence within particular regions, but any such effects are not sufficiently powerful or pervasive to noticeably disturb the spatial structure of prices (R-squared results in Figures 9 and 10), or drive outliers in the spatial price distribution to the national mean (slope coefficients in Figures 9 and 10).

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requirements because of too few underlying plant-level observations. In the regressions, we weighted each included observation by the square root of the number of plants used to compute the fixed effect.

There are many potential determinants of spatial price differences, which differ in their ease of measurement. Potentially important factors include state and local taxes on purchased electricity, rate-setting procedures, the age and efficiency of the distribution network, and fuel sources used for electricity generation. Regional differences in the relative importance of hydro, nuclear and the mix of fossil fuels clearly have major and time-varying effects on spatial differences in the cost of electricity generation. We focus on generation fuel sources as a determinant of spatial prices differences for these reasons and because we have state-level data on generation fuel sources. Figure 11 shows the pattern of U.S. real prices for coal, natural gas, and crude oil from 1960 to 2000. Coal has by far the most stable prices, with coal prices rising significantly in the 1970s and then declining slowly. Crude oil and natural gas prices are much more volatile. Further, some states, California for example, have stringent environmental laws that raise the cost of electricity generation and transmission.

We quantify the impact of state-level differences in electricity generation sources on spatial dispersion in electricity prices by regressing the purchase-weighted state mean log real price of electricity on state fuel shares of electricity generation by year.[24] The residual from this regression provides us with a nice estimate of the amount of the variation in log price that is not due to differences in generation fuel source. Figure 12 shows the between-state standard deviation of log price of electricity, the between-state standard deviation of log price of electricity without the contribution of fuel effects (the standard deviation of the residual), and the between-state standard deviation of log price of electricity due to fuel effects. We see that the composition of generation fuel sources accounts for a large part of the variation and much of the volatility in the between-state standard deviation of log price of electricity.

We show above that both the price-quantity schedule and electricity generation fuel sources affect the spatial dispersion of electricity prices. We run the purchase-weighted plant-level regression (3) to understand the combined effects of quantity discounts and generation fuel sources on spatial price dispersion.

$$\begin{aligned} lpe_e = {} & \alpha_1(\log PE_e) + \alpha_2(SHARE\_GEN\_CL_s) + \alpha_3(SHARE\_GEN\_HY_s) \\ & + \alpha_4(SHARE\_GEN\_PN_s) + \alpha_5(SHARE\_GEN\_NU_s) \\ & + \alpha_6(SHARE\_GEN\_OT_s) + \varepsilon_e \end{aligned} \tag{3}$$

where *e* represents a plant, *s* represents the state where plant *e* is located, *lpe* is the log price of electricity, *PE* is the quantity of purchased electricity, $SHARE\_GEN\_CL_s$ is the share of total electricity generation in state *s* from coal, $SHARE\_GEN\_PN_s$ is the share of total electricity generation in state *s* from petroleum and natural gas, $SHARE\_GEN\_HY_s$ is the share of total electricity generation in state *s* from hydropower, $SHARE\_GEN\_NU_s$ is the share of total electricity generation in state *s* from nuclear power, and $SHARE\_GEN\_OT_s$ is the share of total electricity generation in state *s* from other fuel sources. We see in Figure 13 that together purchase amount and state-level fuel measures account for a large part of the between-county variation in log electricity prices. As we saw in Figure 12, the fuel measures account for a good deal of the volatility in the spatial dispersion of electricity prices. This is due in part to spatial sorting; the largest electricity purchasers tend to be located in states with cheaper electricity and states with cheaper electricity generally use a lot of hydropower.

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[24] The regression is weighted by a state-year weight equal to the sum of the ASM sample weight times

7. Conclusions

To be written.

purchases for all plants in the state in the year divided by the sum of the ASM sample weight times purchases for all plants in the sample in the year.

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Table 1. Selected Characteristics of the PQEM Database

Years covered	1963, 1967, 1972-2000
Number of plant-level observations per year	48,164 to 72,089
Total number of annual plant-level observations[a]	1,814,457
Number of counties with manufacturing plants	3,029
Number of 4-digit SIC industries (1972 / 1987)[b]	447 / 459
Number of best-match utilities[c]	349
Mean annual electricity purchases (GWh)[d]	99.7 (859.7)
Standard deviation of annual electricity purchases (GWh)[d]	333.8 (2,399.2)

	Quantiles of Annual Electricity Purchases, Gigawatt-hours (GWh)								
Weighting Method	1	5	10	25	50	75	90	95	99
Shipments	.07	.30	.70	3.21	16.3	89.0	267	443	996
Purchases	.20	1.07	2.82	13.53	85.7	451	2,089	4,089	14,000
Weighting Method	Quantiles of Electricity Costs as a Percent of Total Labor Costs								
Shipments	0.4	1.1	1.5	2.6	4.7	10.3	25.8	46.4	102.8
Purchases	1.2	2.2	3.1	6.5	18.4	65.3	205.4	309.5	853.3

Notes:
[a] The initial sample contains 1,937,282 records. We drop 438 records because of invalid geography codes and 121,460 (6.2%) 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 each year (927 observations over all years).
[b] We use 1972 SIC codes in 1963, 1967, and 1972-1986 and 1987 SIC codes in 1987-2000. See Davis et al. (2004) for additional information.
[c] There are 336 best-match utilities not counting public power authorities: Tennessee Valley Authority, Bonneville Power Administration, New York Power Authority, Santee Cooper, Grand River Dam Authority, and the Colorado River Commission of Nevada. By construction, a best-match utility does not cross state lines.
[d] Computed from the shipments-weighted (purchase-weighted) distribution.

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	.417	.473	.429	.369	.359	.347	.373	.388	.360
Price Dispersion Between Industries									
4-Digit SIC (447/459)+									
Between Variance as % of Total	37.2	36.7	28.0	20.6	19.4	23.1	26.4	25.1	23.8
Between Standard Deviation	.255	.287	.227	.167	.158	.167	.192	.194	.175
Price Dispersion Between Geographic Areas									
NERC Regions (12)									
Between Variance as % of Total	7.2	9.5	12.6	13.1	17.8	14.9	22.1	20.8	21.2
Between Standard Deviation	.112	.146	.152	.134	.152	.134	.175	.177	.166
States (51)									
Between Variance as % of Total	10.0	13.7	17.4	34.8	46.5	36.7	42.7	39.4	38.1
Between Standard Deviation	.132	.175	.179	.218	.245	.210	.243	.244	.222
Utilities (349)									
Between Variance as % of Total	16.8	21.1	22.6	42.2	56.0	44.3	50.2	46.8	45.1
Between Standard Deviation	.171	.217	.204	.240	.269	.231	.264	.266	.241
Counties (3,029)									
Between Variance as % of Total	29.3	32.1	32.3	53.0	67.1	54.3	61.6	57.6	56.4
Between Standard Deviation	.226	.268	.244	.269	.294	.256	.292	.295	.270
Price Dispersion Between Groups Defined by Annual Electricity Purchases									
Purchase Deciles (10)									
Between Variance as % of Total	58.7	54.6	33.2	16.4	19.3	26.2	29.0	30.6	25.6
Between Standard Deviation	.319	.350	.247	.150	.158	.177	.201	.215	.182
Purchase Centiles (100)									
Between Variance as % of Total	63.6	57.8	35.8	18.6	21.6	28.7	31.9	32.7	29.0
Between Standard Deviation	.333	.360	.257	.159	.167	.186	.210	.222	.194
Price Dispersion Between Groups Defined by Utility and Purchase Level									
Utility x Purchase Decile (2,585)									
Between Variance as % of Total	73.6	69.5	55.3	59.0	71.8	65.5	72.2	70.1	68.2
Between Standard Deviation	.358	.395	.319	.283	.304	.281	.317	.325	.297
Utility x Purchase Centile (21,644)									
Between Variance as % of Total	83.8	79.0	66.4	69.7	81.1	76.6	82.6	81.4	80.1
Between Standard Deviation	.382	.421	.350	.308	.323	.304	.339	.350	.322

+ Years prior to 1987 are classified using the 1977 SIC system (447 4-digit industries).
Years 1987 and later are classified using the 1987 SIC system (459 4-digit industries).

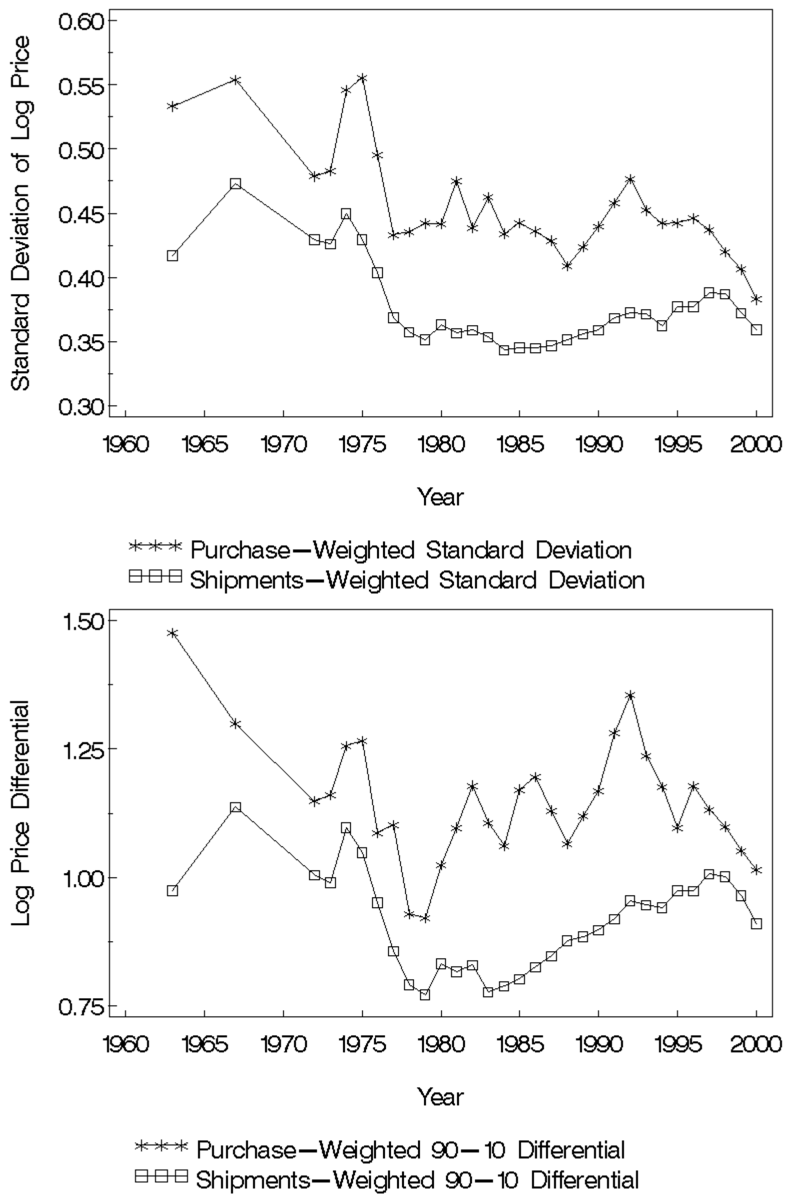
Source: Authors' calculations on PQEM data.

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	.533	.554	.479	.433	.439	.429	.477	.437	.383
Price Dispersion Between Industries									
4-Digit SIC Industries (447/459)									
Between Variance as % of Total	71.3	61.9	48.8	40.9	37.9	46.8	59.0	44.5	37.5
Between Standard Deviation	.450	.436	.334	.277	.270	.293	.366	.292	.235
Price Dispersion Between Geographic Areas									
NERC Regions (12)									
Between Variance as % of Total	17.0	17.0	19.5	8.8	10.3	8.1	11.0	10.0	13.9
Between Standard Deviation	.220	.229	.212	.129	.141	.122	.158	.139	.143
States (51)									
Between Variance as % of Total	42.1	40.9	37.5	40.0	45.7	38.3	39.3	37.5	39.6
Between Standard Deviation	.346	.354	.293	.274	.297	.265	.299	.268	.241
Utilities (349)									
Between Variance as % of Total	62.0	55.6	49.6	55.7	62.1	55.3	56.0	51.9	50.6
Between Standard Deviation	.420	.413	.337	.323	.346	.319	.357	.315	.272
Counties (3,029)									
Between Variance as % of Total	76.1	69.8	64.9	73.5	78.6	74.9	77.5	69.8	65.5
Between Standard Deviation	.465	.463	.386	.371	.389	.371	.420	.365	.310
Price Dispersion Between Groups Defined by Annual Electricity Purchases									
Purchase Deciles (10)									
Between Variance as % of Total	63.9	56.5	36.1	27.4	24.7	38.0	49.5	41.2	38.0
Between Standard Deviation	.426	.416	.288	.227	.218	.264	.335	.281	.236
Purchase Centiles (100)									
Between Variance as % of Total	75.0	65.9	41.4	33.8	31.8	45.0	60.8	45.9	43.4
Between Standard Deviation	.462	.449	.308	.252	.247	.288	.372	.296	.252
Price Dispersion Between Groups Defined by Utility and Purchase Level									
Utility x Purchase Decile (2,585)									
Between Variance as % of Total	88.8	82.6	69.7	73.2	78.6	76.5	80.7	75.3	72.9
Between Standard Deviation	.503	.503	.400	.370	.389	.375	.428	.379	.327
Utility x Purchase Centile (21,644)									
Between Variance as % of Total	94.0	90.5	80.4	83.3	88.1	87.5	90.4	86.4	84.6
Between Standard Deviation	.517	.527	.429	.395	.412	.401	.453	.406	.352

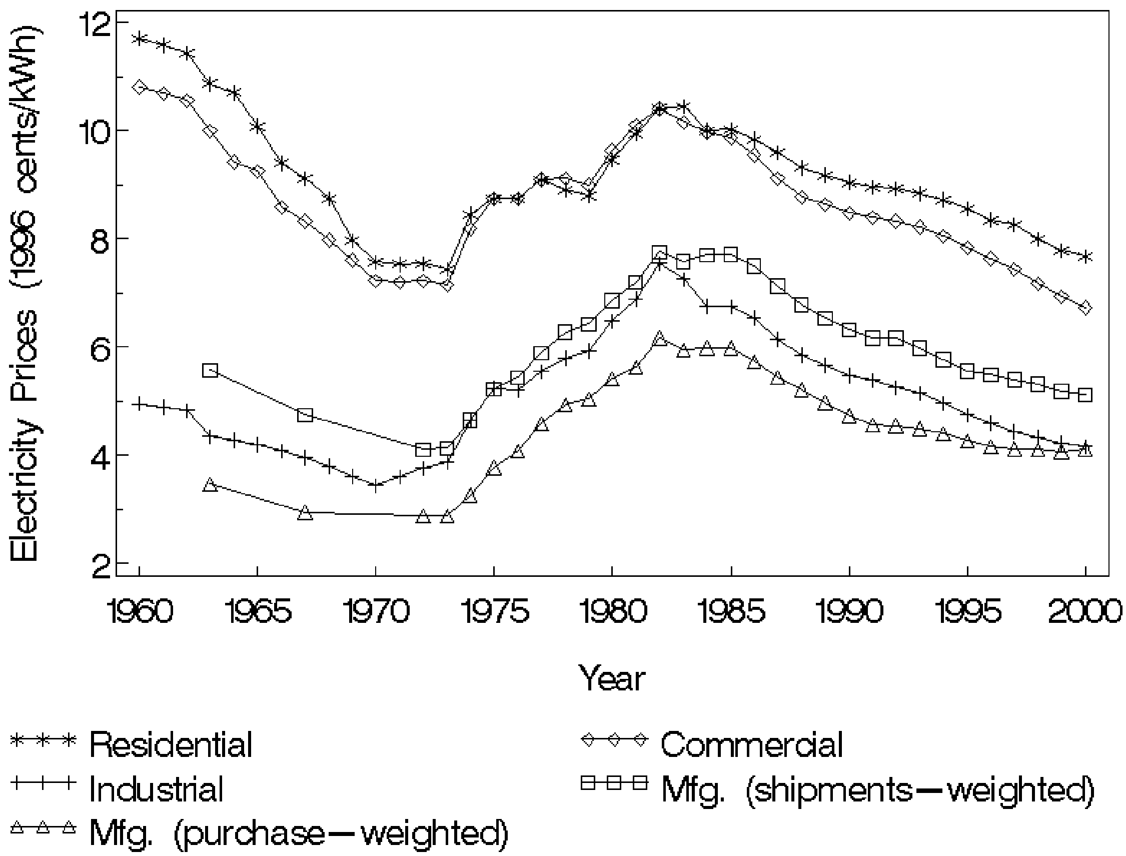
[+] Years prior to 1987 are classified using the 1977 SIC system (447 4-digit industries). Years 1987 and later are classified using the 1987 SIC system (459 4-digit industries).

Source: Authors' calculations on PQEM data.



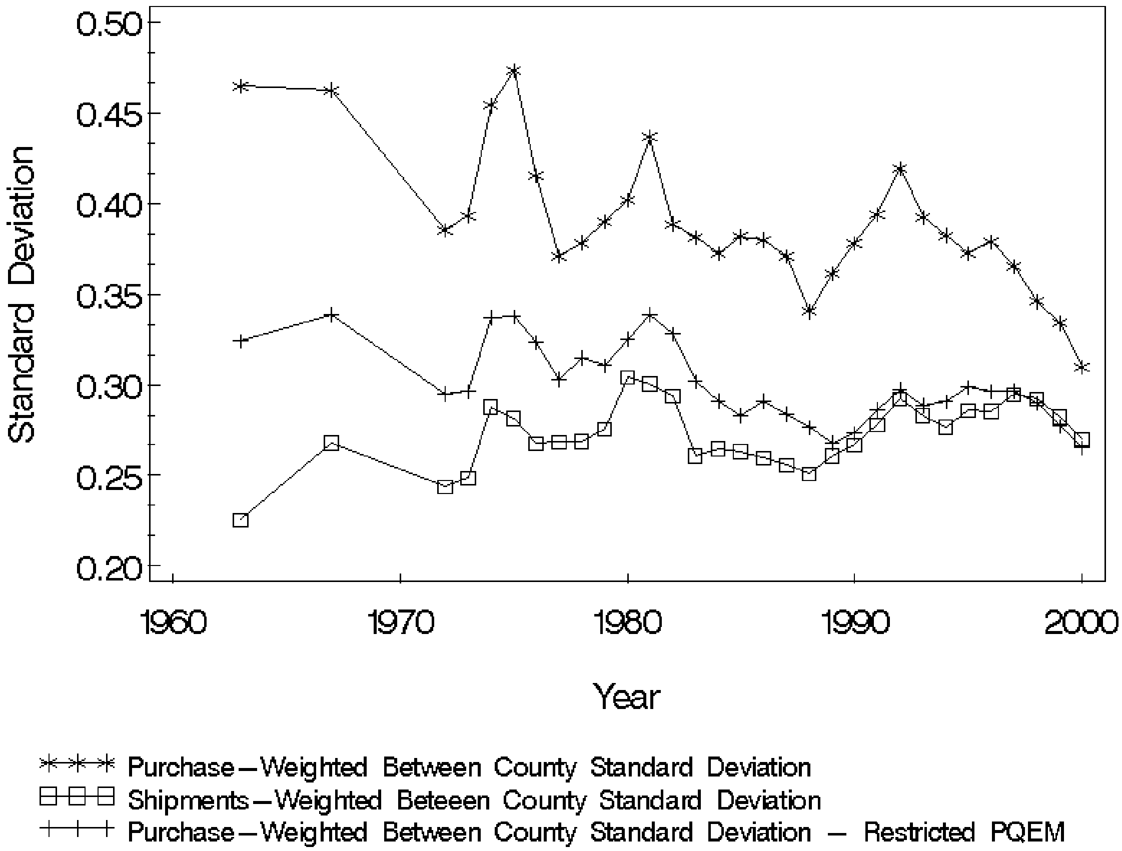
Source: Authors' calculations on PQEM data.

Figure 1. Electricity price dispersion among U.S. manufacturing plants, 1963-2000



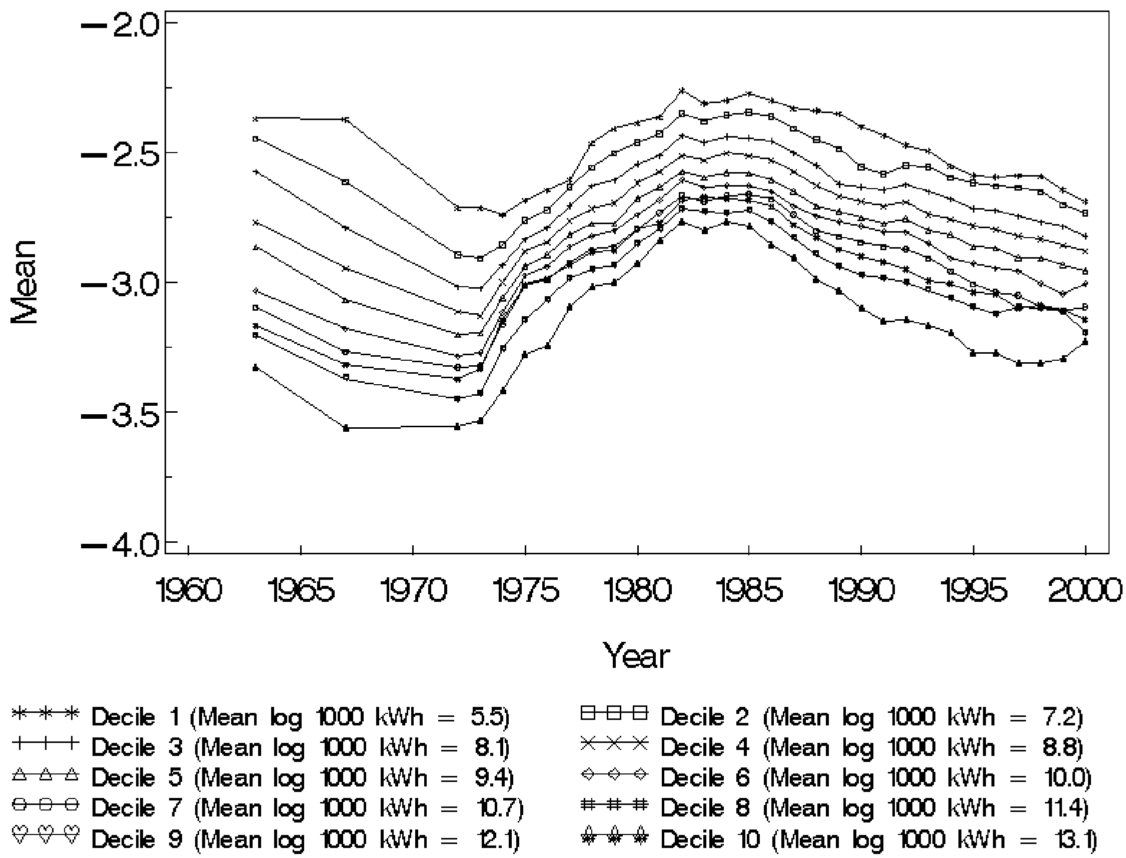
Source: Energy Information Administration for Residential, Commercial and Industrial series; authors' calculations on PQEM data for Manufacturing.

Figure 2. Real electricity prices by end-use sector, 1960-2000



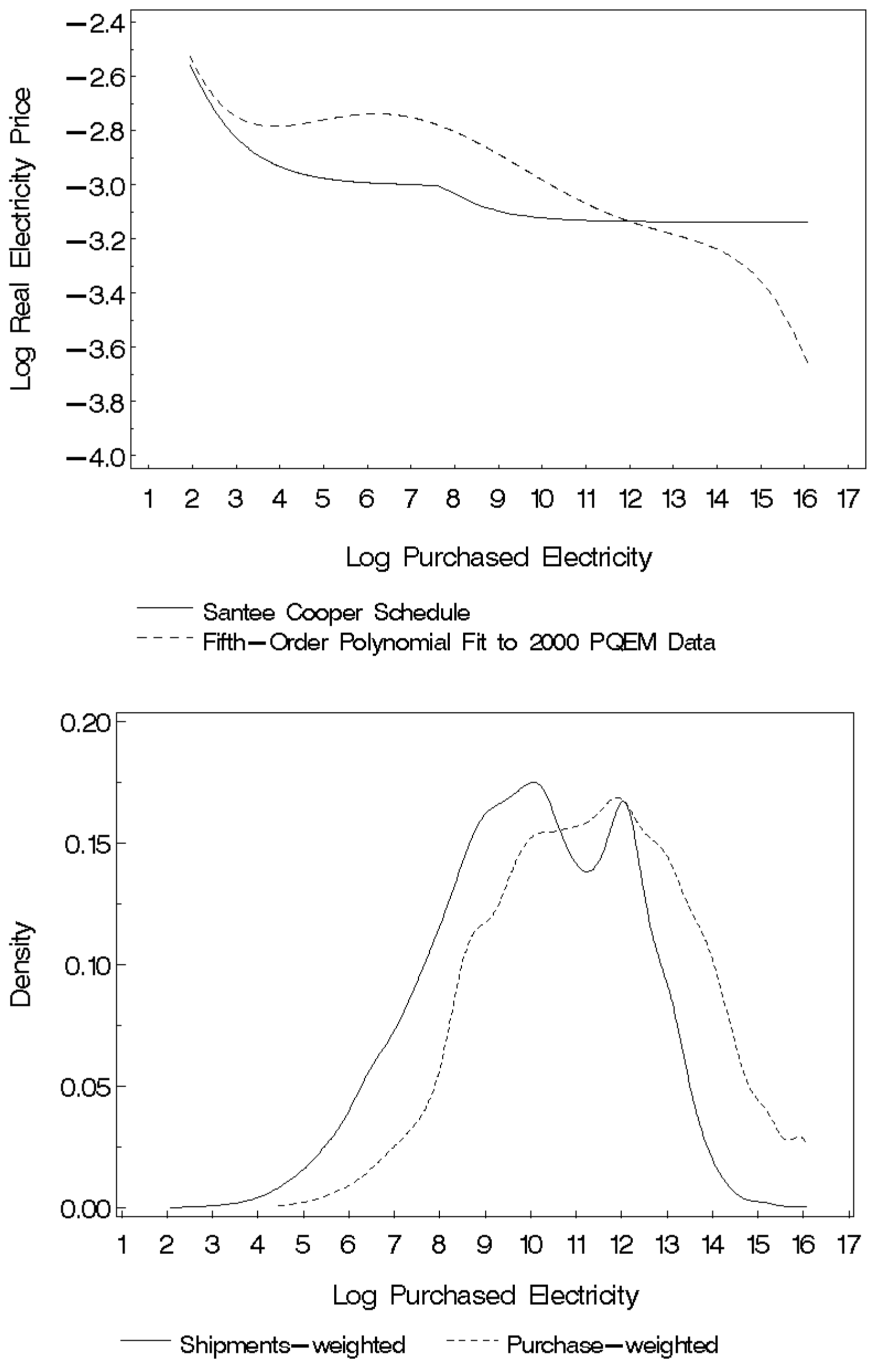
Source: Authors' calculations on PQEM data.
Note: The restricted sample excludes plants that purchase more than 965 gigawatt-hours of electricity during the year. There are 16-56 plants that meet this condition in any given year.

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



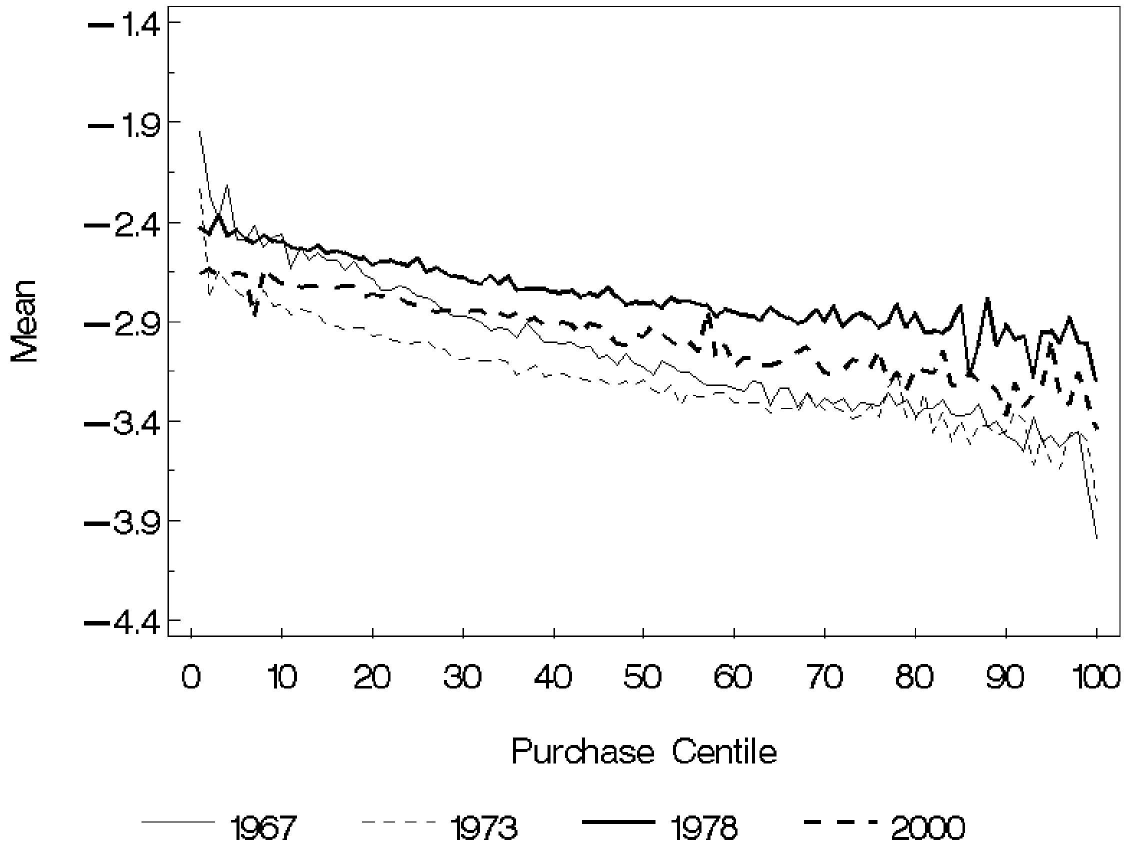
Source: Authors' calculations on shipments-weighted PQEM data.

Figure 4. Mean of log real electricity prices by purchase deciles, 1963-2000



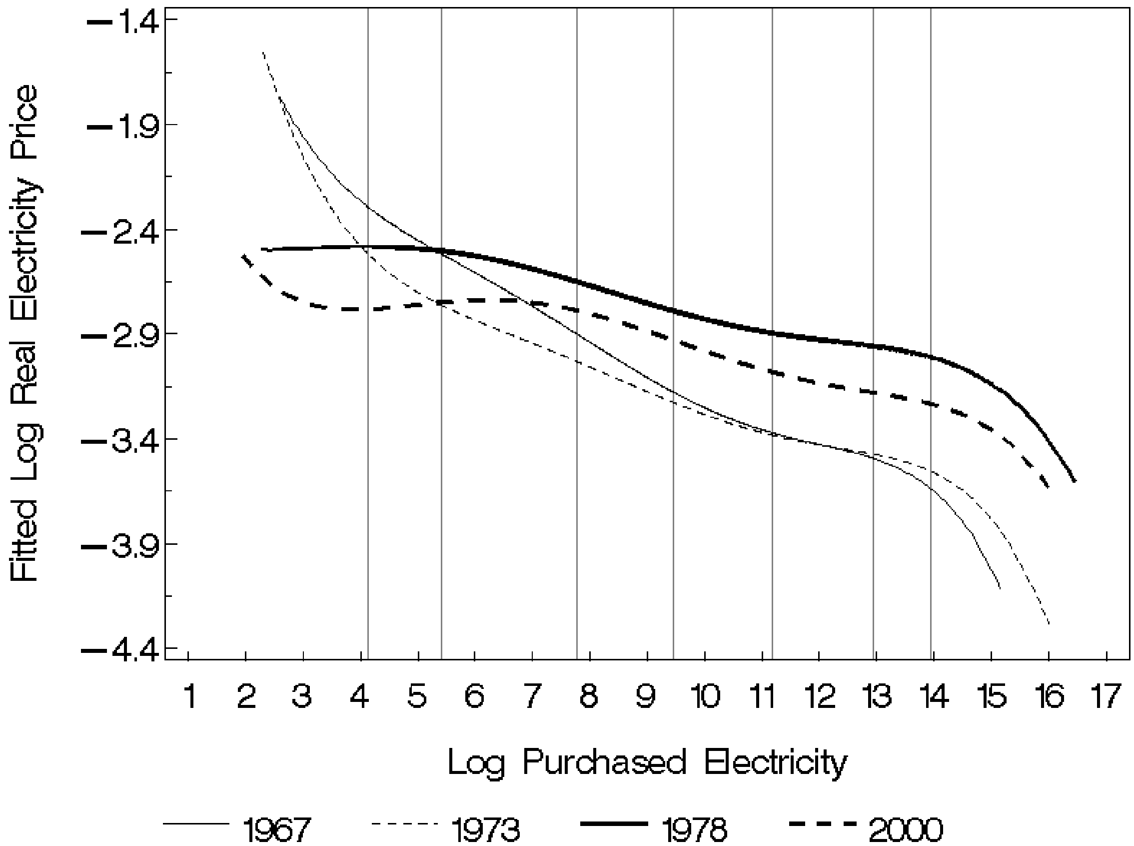
Source: Authors' calculations on PQEM data and Santee Cooper price schedules

Figure 5. Electricity prices and purchase distributions, U.S. manufacturing sector, 2000



Source: Authors' calculations on shipments-weighted PQEM data.

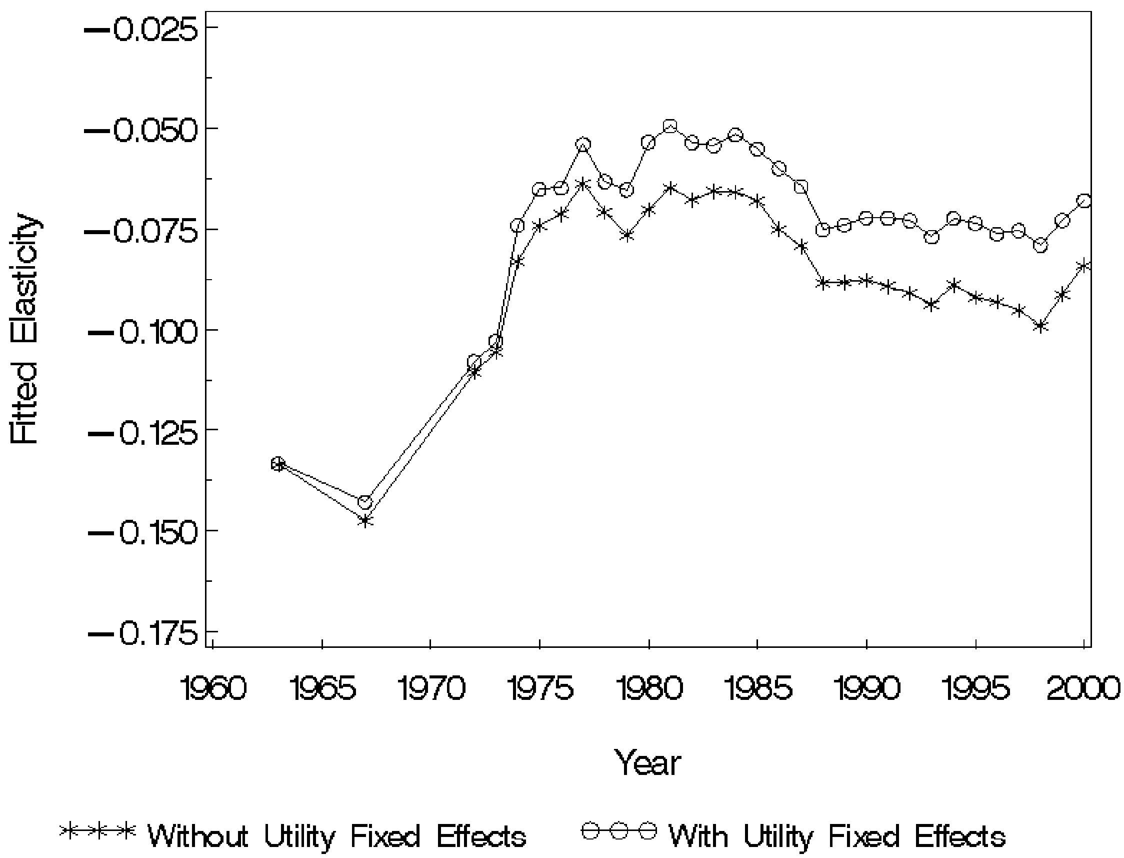
Figure 6a. Mean log real electricity prices by annual purchase level



Source: Authors' calculations on shipments-weighted PQEM data.

Note: Vertical lines depict the 1st, 5th, 25th, 50th, 75th, 95th and 99th percentiles of the shipments-weighted distribution of annual purchases.

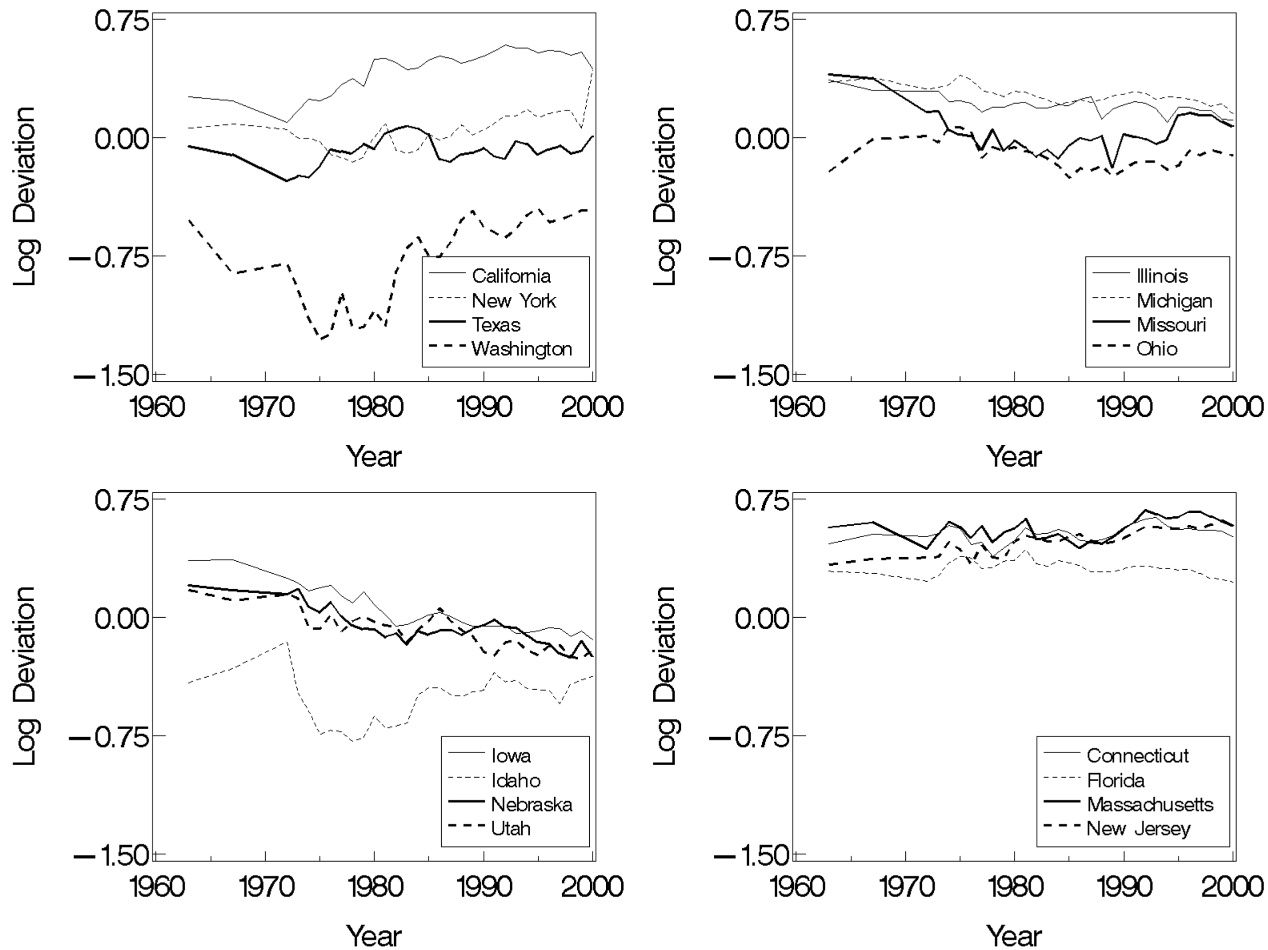
Figure 6b. Log electricity price fit to fifth-order polynomials in log purchases



Source: Authors' calculations on shipments-weighted PQEM data.

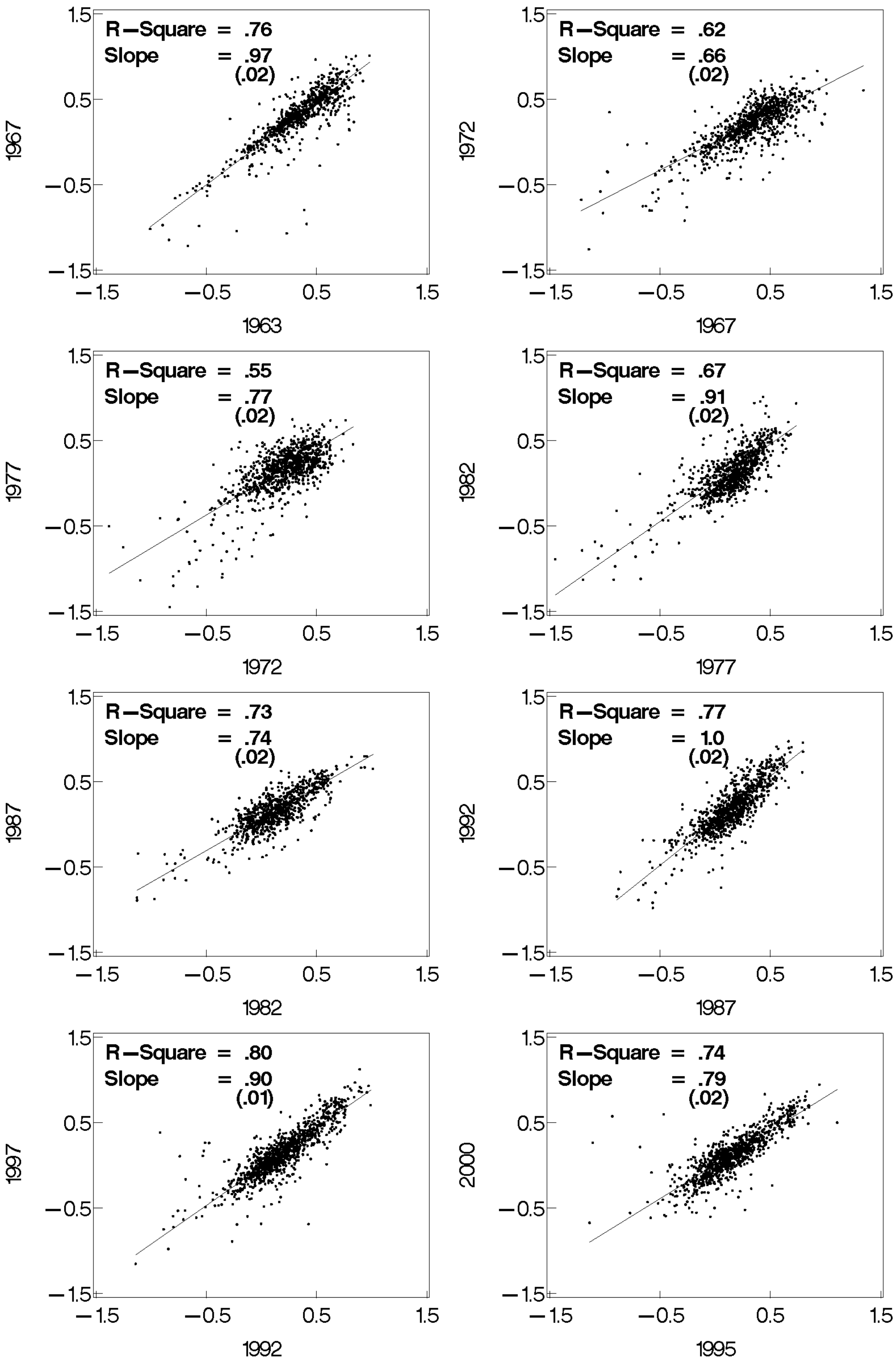
Note: Elasticity fits are based on a log-linear regression specification.

Figure 7. Elasticity of electricity price with respect to annual purchases, 1963-2000



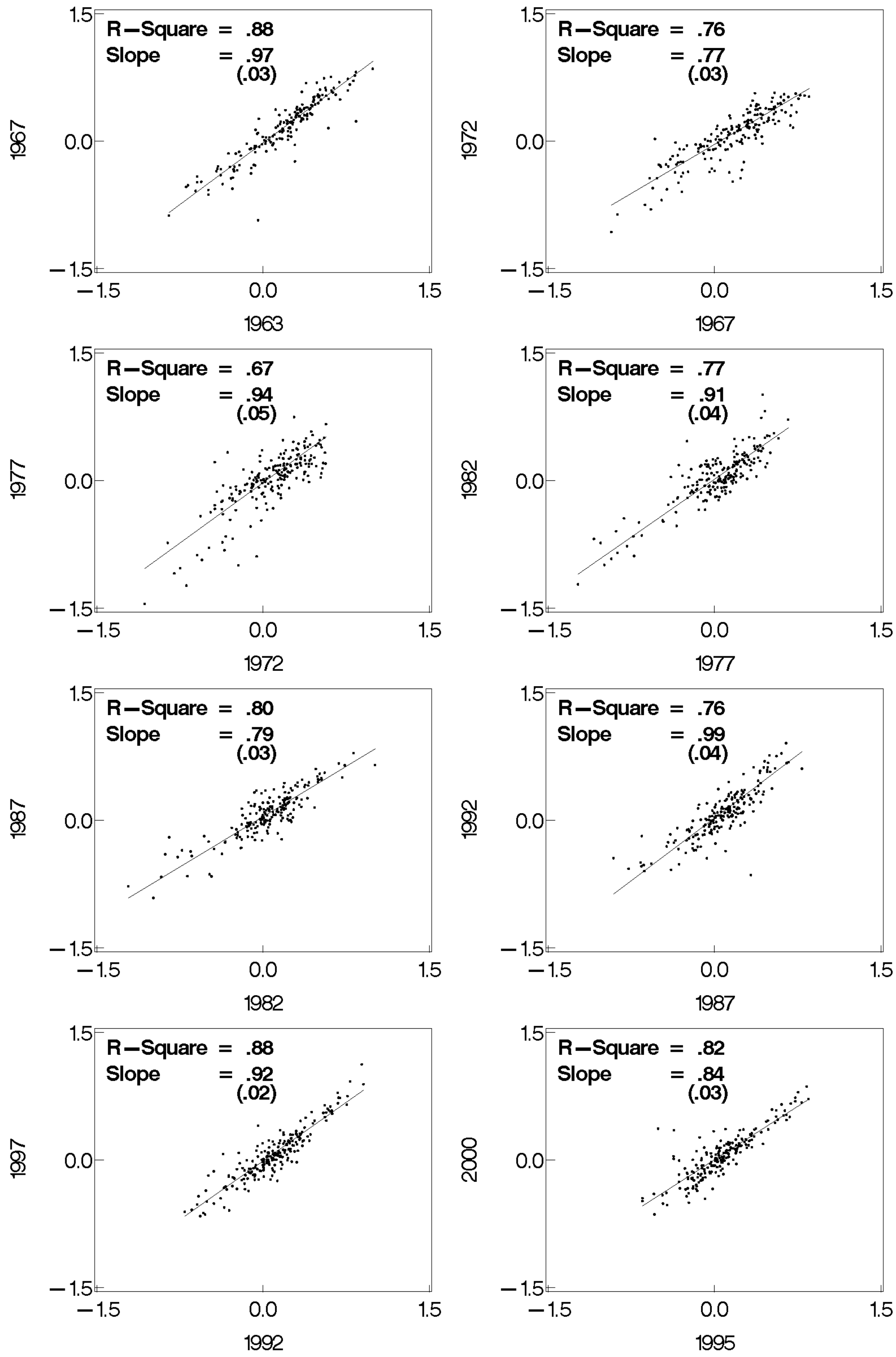
Source: Authors' calculations on purchase-weighted PQEM data.

Figure 8. State-level deviations of log electricity prices from the national average, 1963-2000



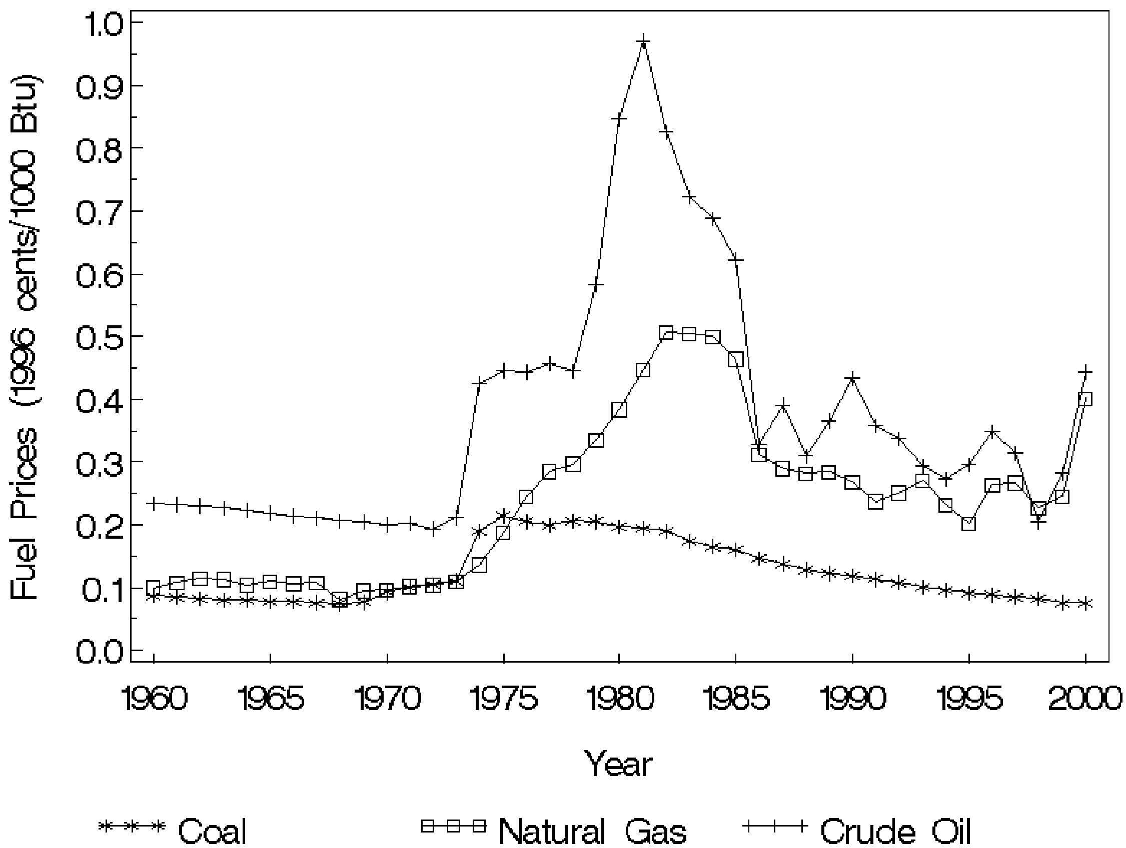
Source: Authors' calculations on purchase-weighted PQEM data.

Figure 9. Scatter plots of county effects, selected year-pairs



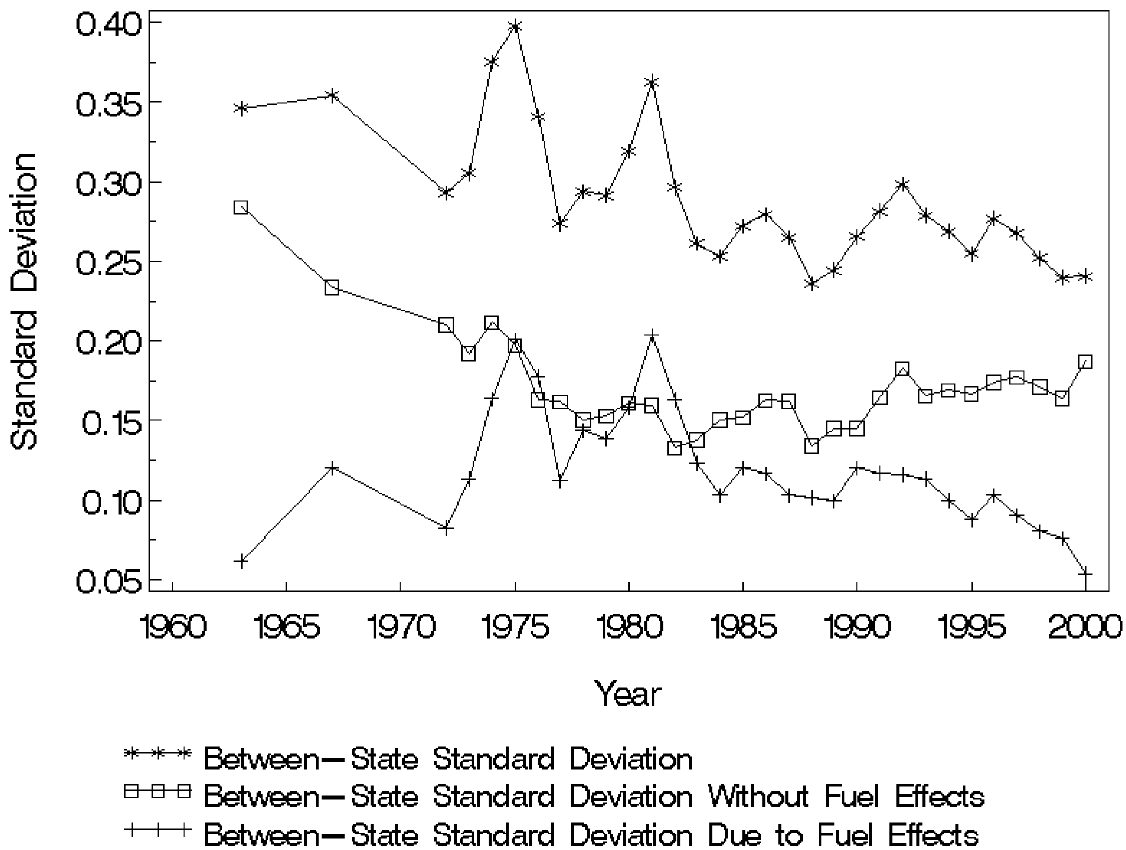
Source: Authors' calculations on purchase-weighted PQEM data.

Figure 10. Scatter plots of utility effects, selected year-pairs



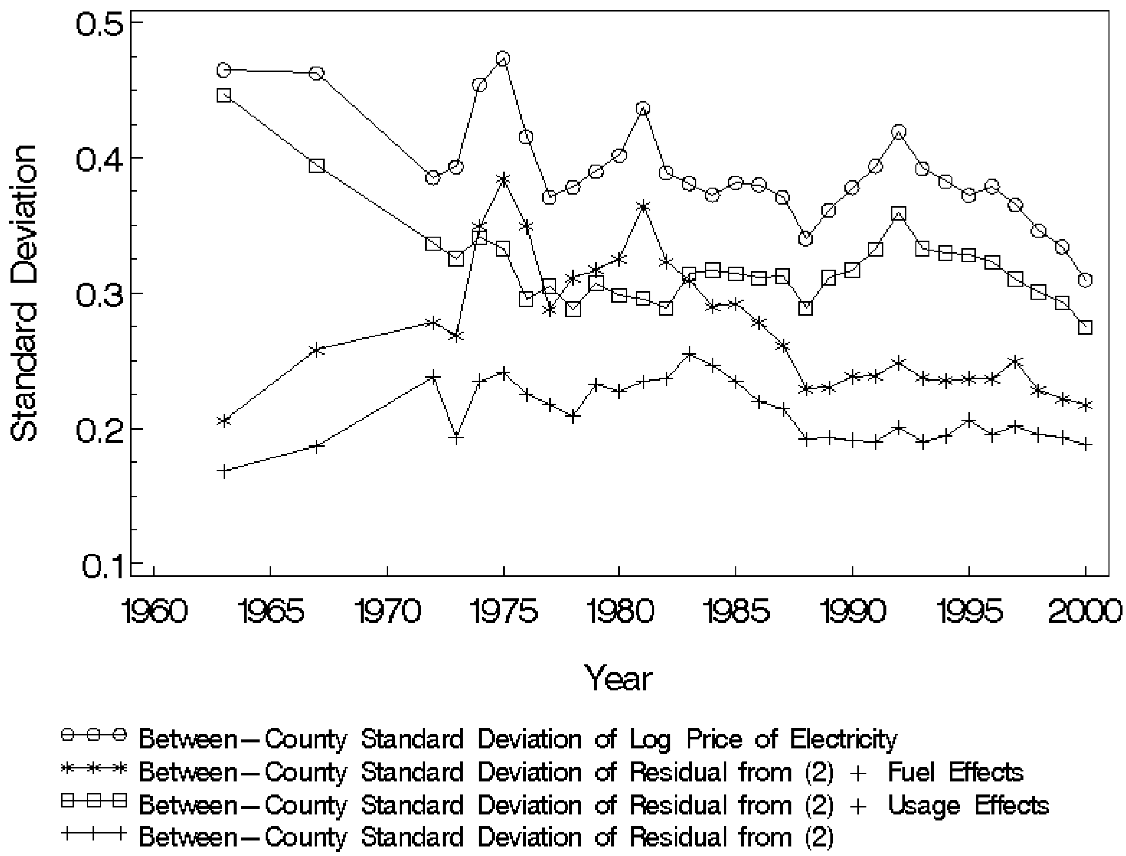
Sources: Energy Information Administration's Annual Energy Review

Figure 11. Real fuel prices, 1960-2000



Source: Authors' calculations on purchase-weighed PQEM data.

Figure 12. Fuel-mix differences and disturbances to the spatial structure of electricity prices



Source: Authors' calculations on purchase-weighted PQEM data.

Figure 13. Purchase-weighted between-county standard deviations, log price of electricity, residual from (2) + fuel effects, residual from (2) + usage effects, and residual from (2)