ALFRED P. SLOAN FOUNDATION
Industry Studies
Annual Conference | May 1 - 2, 2008 | Boston, MA
2008
http://web.mit.edu/is08/program

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Abstract

Restructuring of the electricity industry was expected to improve the operating efficiency of electric power generators, leading to lower production costs and retail prices. Most studies conclude that there have been some efficiency gains, but the subject of whether retail prices have fallen has been contentious. The existing literature has a number of shortcomings, including the use of blunt or inappropriate definitions of restructuring, failure to incorporate the effects of regulatory decisions regarding price caps and stranded cost recovery, and the use of highly aggregated data. Our study addresses many of these problems and thus represents a significant improvement on existing work. We use a detailed firm-level data set to estimate how the markets and institutions established as a part of "restructuring" have affected the difference between prices and costs. Based on a number of different definitions, we find that utilities that have undergone restructuring display significantly higher price-cost markups than utilities that remained traditionally regulated. We find that some elements of restructuring are associated with higher price-cost margins, while others appear to be uncorrelated with prices and costs. The combination of introducing retail competition into an electric utility's operating territory and divestiture of that utility's generating assets has increased costs, but has increased prices even more. In particular, we find an average difference of 2 to 3 cents per kWh between prices and costs that is explained by restructuring rather than by increases in fuel prices. We conclude that restructuring has been beneficial to companies that restructured, but the evidence is far less clear concerning benefits to consumers.

1. Introduction

Electricity restructuring in the United States has its roots in the combination of the 1970s energy crises and the high costs involved in efforts to decouple the U.S. electric system from the world petroleum market. Poor oversight and management of nuclear power facilities combined with generous contract terms for unconventional generators added to the problem of rising consumer electricity prices. Modern restructuring efforts in the U.S. electricity industry began in 1992 with the first Energy Policy Act, which allowed non-utility generators and marketers to compete in the same nascent wholesale markets as traditional vertically-integrated utilities. The 1996 issuance of Order 888 by the Federal Energy Regulatory Commission (FERC) was aimed at increasing competition by removing barriers to access to the utility-owned transmission grid.

Beginning in 1998, individual states began restructuring efforts of their own, with California and Pennsylvania the first to act. Despite the mix of federal and state-level policies, electricity restructuring in most regions and states has several common features (Blumsack, Apt and Lave 2005, Joskow 2006):

1. Traditional electric utilities were vertically unbundled. California, for example, required its three investor-owned utilities (IOUs) to effectively unbundle by divesting themselves of most generation and surrendering control (though not ownership) of transmission assets to an Independent System Operator (ISO) or Regional Transmission Organization (RTO).[1] Utilities in many other states divested themselves of generation assets without an explicit requirement that they do so. Although FERC has promoted surrendering control of transmission assets to RTOs through Order 2000 and its proposed Standard Market Design (SMD), very few utilities have actually surrendered ownership of transmission assets.
2. The interconnected North American transmission grid is no longer solely operated and managed by transmission-owning utilities. Many areas of the North American grid are managed by RTOs. These RTOs (and vertically-integrated utilities) dispatch generation

[1] There are subtle differences between ISOs and RTOs, the most significant of which is that an RTO is a regional grid operator with a FERC-approved tariff. California currently has an ISO that is seeking FERC approval for its LMP pricing regime. Texas has an ISO that operates similarly to FERC-approved RTOs, but FERC currently does not exercise jurisdiction over the Texas electric system. In this paper, we will use RTO as a generic term meant to encompass all regional grid operators that also run centralized markets for electric energy.

resources within their footprints and are responsible for managing congestion on the grid and ensuring that supply and demand are in balance.

3. Many RTOs also run a series of centralized auction markets for electric energy, capacity, transmission rights, and other ancillary services. The exact auction structure varies among RTOs, but common to nearly all are "spot" markets for electric energy, conducted one day ahead and one hour ahead of actual delivery and consumption.
4. A number of states have introduced retail competition for electric generation (as distinct from the transmission and distribution services traditionally provided by the regulated utility). Under retail competition, individual consumers are allowed to choose from among a number of non-utility generation suppliers. Those who do not choose one of these competitive suppliers are assigned to a "default" supplier and electric rate schedule, usually from the incumbent distribution utility.
5. Utilities have been allowed to recover so-called "stranded costs," most of which represent investments made under regulation that would likely not have been made in a competitive environment. Examples include nuclear and renewable generation investments. Stranded cost recovery has come about largely through surcharges on customer bills.

Initially, restructuring was driven by the dual goals of fixing a regulatory system that was perceived to be fundamentally flawed, and reducing prices to consumers. A secondary goal was to reduce the amount of refined petroleum used in U.S. electric generation. For the first eight decades in the history of the electric power industry, prices fell nearly every year as technological advances increased generation efficiency, as shown in Figure 1. The oil crises in the 1970s, combined with massive cost over-runs in new large generators (particularly nuclear plants), depressed demand and increased costs. Average rates rose accordingly, and on average have continued to rise since then.

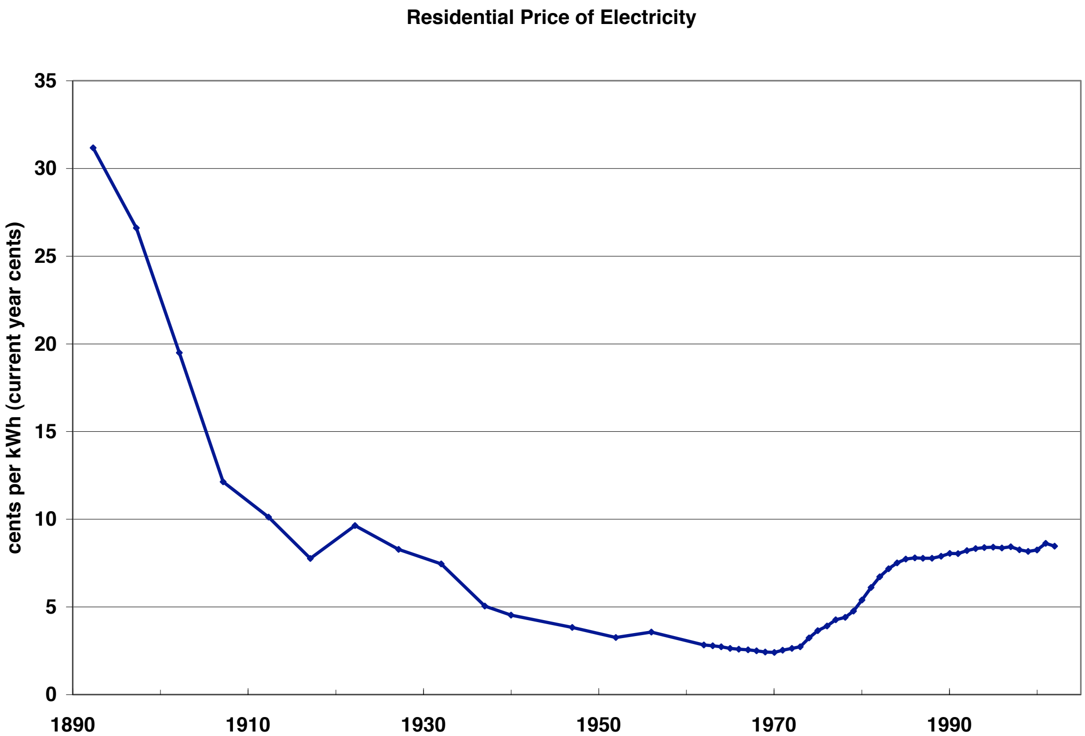

Figure 1: Residential price of electricity, in current-year cents per kilowatt-hour. Source: Morgan, et al. (2005).

Later stages of electricity restructuring have been driven by a variety of policy goals, including improving operating efficiency at generators, reducing the cross-subsidies present in regulated rates, and reducing pollution. Ultimately, many of the goals of restructuring were focused on reducing costs and prices through the introduction of competitive markets for electric generation (Joskow and Schmalensee 1983, de Vries 2004). In issuing its preferred electricity market design, FERC stated an explicit policy goal of introducing competition at the retail and wholesale level, so that market prices would reflect marginal generation costs (FERC 2003). Particularly in light of wholesale price spikes related to the manipulation of markets in California in 2000-01, the issue of whether restructuring has benefited consumers has been controversial.

We examine the behavior of costs and prices for investor-owned electric utilities under regulation and restructuring. We use a detailed firm-level data set to construct average annual costs of electric service, and compare the difference between our estimated costs and utility-reported electric rates over time, for three different classes of customers. Our data set allows us to decompose "restructuring" into three separate policies: joining an RTO, divestiture of generation assets, and the introduction of retail competition. The way that we construct our cost estimates also allows us to incorporate the effects of rising fuel prices. Given the existing evidence that restructuring has yielded efficiency gains in production, the economic issue becomes how those efficiency gains have been shared between producers and consumers. Existing policy goals reflect an economic hypothesis that competition should decrease the difference between prices and costs following restructuring, after accounting for fuel price changes. Our analysis of the data does not support this hypothesis. Overall, the various policy choices involved in electric restructuring since the mid 1990s are associated with larger markups of rates over costs for those utilities that have undergone restructuring, indicating that most of the gains associated with restructuring have, thus far, been enjoyed by producers. Our results are consistent with some of the existing literature (particularly Apt 2005 and Tabor, Chapman and Mount 2007, discussed below) suggesting that consumers have not enjoyed large benefits from restructuring in the form of lower prices. Of the policies we are able to analyze, divestiture and the introduction of retail competition are consistently associated with higher price-cost markups, while simply being within the footprint of an RTO does not appear to have a significant effect.

The remainder of the paper is organized as follows. Section 2 reviews the existing evidence on whether electricity restructuring has produced efficiency gains in production, and whether consumers have seen lower electric rates as a result. Section 3 introduces the data and econometric model used in this analysis. A discussion of the results is in Section 4, and Section 5 offers some concluding thoughts.

2. Electric Restructuring, Production Efficiency, and Retail Prices

Many capital-intensive network industries have successfully been deregulated in one form or another. Natural gas and airline deregulation commenced in 1978, followed by trucking and railroads in 1980. Deregulation in natural gas is generally viewed as having increased industry efficiency and benefited consumers (de Vany and Walls 1993). Deregulation in transport and shipping industries has also generally been considered successful (Crandall and Ellig 1997, 1998). In particular, Crandall and Ellig (1998) note that prices in these industries dropped dramatically (25% or more) within 10 years following the inception of deregulation.

Smaller (but still significant) efficiency gains of 3% to 13% were expected as a result of restructuring in electricity (Christensen and Greene 1976, Klitgaard and Reddy 2000, Kleit and Terrell 2001). In electric generation, capital costs represent a large proportion of total costs, so efficiency gains in production of electricity in the short-term were expected to stem largely from using low-cost generation assets more intensively. Increased labor productivity was expected, but since labor makes up only 7% of the total cost of electricity (Apt 2005), the contribution of labor to overall cost reductions was likely to be small. In the long-run, old and inefficient plants were expected to be replaced.

Overall, restructuring (or the anticipation of competition) appears to have produced efficiency gains in several areas of the electric generation sector. Niederjohn (2003) reports that employment in electricity generation dropped by 29% in states that underwent restructuring, compared to a 19% overall decrease in the sector's employment. As a group, generators in states that have retained the traditional regulatory structure have seen smaller efficiency gains than generators in restructured states (Wolfram 2005; Fabrizio, Rose and Wolfram 2007). The biggest gains have come in the increased utilization rates of low-cost generation sources.[2] Douglas (2006) estimates that the introduction of centralized regional electricity markets has increased the utilization of low-cost coal-fired power plants, relative to high-cost coal plants, with cost savings between 2% and 3%. Meanwhile, high fuel prices have caused the utilization rates of gas-fired generators to plummet starting in 2000 (Blumsack, Apt and Lave 2005).[3] The most striking improvement has come from the U.S. nuclear sector, which has increased average utilization (or availability) rates from less than 60% in the 1970s to over 90% in 2006. Blumsack and Lave (2004) and Zhang (2006) present evidence tying these efficiency gains to electricity restructuring, while a different conclusion is reached by Spinner (2006) and the American Public Power Association (2007).

[2] Primarily coal and nuclear generation, these low-cost resources represent the "base load" generating assets that operate for days or months at a time.

[3] Between 1999 and 2002, the U.S. electric sector added nearly 50 gigawatts (GW) of new gas-fired generation, and around 10 GW of new generation from all other fuel sources combined. During that same period, consumption of natural gas for electricity increased by 50% and wholesale prices for natural gas tripled. Utilization of this new gas capacity was low, since the generators were effectively priced out of the market.

Overall, the evidence on production efficiency suggests that measurable gains have been made since electric industry restructuring, though the distribution of gains among various facets of the generation sector has varied widely. We may thus conclude that, in general, restructuring has lowered the cost of producing electric power in those areas where restructuring has occurred. As to whether these cost savings have flowed down to consumers in the form of lower prices, the evidence is far less clear.

To date, more than a dozen studies have been produced examining the effects of restructuring on electricity prices (Kwoka 2006, Lave, Apt and Blumsack 2007a,b). The studies vary widely regarding scope, method, and conclusions. Two types of comparisons are generally used throughout this literature. The first is a time-series comparison of electricity prices within some region (wholesale or retail) prior to restructuring with the same set of prices following the introduction of restructuring and competitive generation markets. The second is a cross-sectional comparison of electricity prices in areas that have undergone restructuring with those that have retained the traditional model of regulated electric utilities. Some studies combine cross-section and time-series data to perform a panel analysis of electricity prices. With respect to the time dimension of electricity prices (that is, the aspect of some studies comparing prices before and after restructuring), some studies simply compare prices between the two periods, while others attempt to construct a counterfactual argument – an estimate of what electricity prices would have been, had traditional regulation not been replaced with new markets and regulatory institutions. A third comparison method (Apt 2005, used also in Douglas 2006), uses a "differences in differences" approach, focusing on the rate of change in electricity prices under regulation and restructuring rather than the price level itself.

One group of studies focuses on wholesale electric prices or generation costs, without explicitly examining retail prices. These studies are more in the spirit of the production-efficiency studies discussed above (such as Wolfram 2005, Douglas 2006, and Zhang 2006) than with studies of retail prices. Synapse Energy Economics (Synapse, 2004) uses financial and operating data for three generating companies in the PJM region to construct production cost estimates for each of the three companies before and after restructuring. The Synapse study generally finds small, but significant, differences in generating costs. Energy Security Analysis, Inc. (ESAI, 2005) uses a power-flow model of the PJM region to examine the effects of the expansion of the PJM territory on wholesale electricity prices. They conclude that since the PJM expansion brought a large amount of low-cost generation into the PJM operating area, prices in the highest-cost areas of PJM (largely along the eastern seaboard) have declined.

A second (and larger) group of studies, more relevant to this paper, examines the effect of restructuring on retail electricity prices. The Center for the Advancement of Energy Markets (CAEM, 2003) focuses on the portion of the power grid within the PJM footprint. The CAEM study performs some simple quantitative comparisons of retail prices before and after restructuring, and between PJM states and regulated states adjacent to the PJM territory.[4] The study concludes that restructuring in the first five years of the PJM region has saved consumers billions of dollars, with tens of billions of (real) dollars in forecasted future savings. Global Energy Decisions (GED, 2005) focuses not on one particular RTO, but on the entire Eastern Interconnect.[5] The GED study constructs a counterfactual by simulating what generation costs would have been in the absence of restructuring. These simulated costs and prices are compared to actual average electric rates during the regulated period. GED concludes that the introduction of regional electricity markets reduced power purchase costs for utilities by approximately $15 billion, which are assumed to be passed on directly to consumers. Apt (2005) uses a differences-in-differences approach (though without any explicit econometrics) to examine the behavior of the rate of change of industrial electricity prices in regulated and deregulated states. Broadly, Apt finds no correlation between the introduction of restructuring and differences in the rate of change of industrial electricity prices. A more recent piece by Lesser (2007), focusing solely on Pennsylvania, provides a number of arguments and pieces of anecdotal evidence (but no systematic quantitative analysis) suggesting that restructuring has benefited electricity consumers in Pennsylvania.

Other studies of retail electricity prices use a variety of econometric techniques to examine the relationship between electricity restructuring and changes in the behavior of prices faced by

[4] The CAEM study does not perform a panel data analysis. Rather, it performs one set of analysis for prices within PJM over time, and a different analysis comparing prices within the PJM territory to those in regulated states outside of PJM.

[5] Broadly, the North American high-voltage transmission grid is divided into three separate interconnections, with limited ability to transfer electricity between the three. The Eastern Interconnect covers roughly the area east of the Rocky Mountains, while the Western Interconnect covers the area west of the Rockies. Most of Texas forms a third interconnection.

consumers. These studies allow the effects of changes in variables such as fuel prices, the composition of the generation fleet, and industry structure to be decomposed explicitly. A study by Cambridge Energy Research Associates (CERA, 2005) regresses inflation-adjusted retail electric rates from 1978 until 1997 (defined by CERA as the starting point of modern restructuring) on a fuel price variable and a cost-of-capital variable, and then uses that relationship to simulate prices from 1998 through 2003. Comparing these simulated prices with actual prices, the CERA report yields similar savings as CAEM (2003); that savings to consumers have been in the tens of billions of dollars. Fagan (2006) estimates three different models relating electricity prices (or price changes) to: fuel prices; the status of state-level restructuring; and RTO membership. Fagan finds no statistically significant evidence that restructuring, however measured, is related to lower electricity prices. Focusing explicitly on the introduction of retail competition in Texas, Zarkinau and Whitworth (2006) and Zarkinau, Fox and Smolen (2007) find evidence that retail prices for residential and commercial customers have actually increased in areas of Texas where retail competition has been introduced.

Perhaps the two most thorough analyses of retail prices to date have been those of Joskow (2006) and Taber, Chapman and Mount (2006). Joskow's analysis covers average retail prices for residential and industrial customer classes in U.S. states for the period 1970 to 2003. In addition to accounting for inflation, fuel prices and the mix of generation resources, Joskow adds the share of generation from PURPA and non-utility generators (also called independent power producers or IPPs), and a measure of the financial attractiveness of utilities. Joskow finds that the coefficients on PURPA generation are positive, relatively large in magnitude, and statistically significant, indicating that (aside from cost variables such as fuel prices) PURPA requirements beginning in the late 1970s have increased prices in certain states for more than two decades. More relevant to modern restructuring, Joskow finds that larger amounts of power coming from independent generating companies and the introduction of retail competition are both associated with lower retail electricity prices. Overall, Joskow finds that modern restructuring policies have resulted in retail rate decreases of approximately 5% to 10%.

Taber, Chapman and Mount (TCM, 2006) estimate a generalized autoregressive conditional heteroscedasticity (GARCH) model (Bollerslev 1986) of electricity prices in U.S. states covering the period 1990 to 2004. TCM examine average retail prices in four different rate classes (residential, commercial, industrial, and an average over all rate classes), and perform separate analyses for private and public utilities, as well as a number of different definitions of "restructuring." TCM perform their analysis at the utility level rather than at the state level.[6] Their dependent variable of interest is the "price gap" – the difference in prices between utilities that have undergone restructuring and those that have maintained the traditional regulatory and organizational structure. As with other detailed studies of electricity prices, the TCM study includes variables to capture the effects of changes in fuel prices, as well as inter-utility variation in the mix of generating assets. TCM find no evidence that restructuring, however defined, has caused retail electricity prices to decline, relative to utilities that have remained regulated. This main result is robust to many different model specifications.

The existing literature on the relationship between electricity restructuring and retail prices is sufficiently heterogeneous that it is difficult to draw broad conclusions, other than there exists little agreement on whether restructuring has accomplished the policy goal of controlling *prices* as well as *costs*. As Kwoka (2006) and Blumsack (2007) point out, perhaps the broadest conclusion that can be drawn is that the studies from industry and consultants have generally found large price savings (or other consumer benefits) from restructuring, whereas studies from academic researchers have found no evidence linking electricity restructuring with lower retail electric rates.[7]

Drawing policy conclusions based on the existing literature is made more difficult by the wide variance in the methods employed in each of the studies, as well as the overall quality of the studies. Kwoka (2006) provides a careful and thorough review of a dozen studies attempting to link electricity restructuring with retail prices. Kwoka finds significant methodological flaws with *every single study*, and concludes that none of them can be considered exemplars of good econometric work. Thus, he concludes that none of the results from the existing body of research can be trusted with a high degree of confidence.

Kwoka (2006) discusses three broad problems with the methods used in existing studies of electricity restructuring and consumer benefits. The first problem is in the basic definition of

[6] The data set used by TCM is EIA Form 861, which is quite detailed but contains a number of omissions and instances of missing data. TCM address the missing-data problem by substituting available data that, *a priori*, is believed to be highly correlated with the missing data. See Appendix A of TCM.
[7] Joskow's (2006) careful study represents a significant deviation from this trend.

restructuring. Nearly all the studies reviewed here and in Kwoka (2006) use one or more dummy variables to demarcate a point in the data series where regulation ended and restructuring began. This use of dummy variables ignores the fact that "electricity restructuring was not a single event that occurred at one point in time."[8] Within a single state, for example, different utilities chose to join RTOs during different years, or at different times within the same year. In a state-level study, deciding on a single month or year when a particular state transitioned from "regulated" to "restructured" may be arbitrary at some level.

The second problem discussed by Kwoka is that the available retail price data may not reflect all of the relevant regulatory and institutional changes involved in restructuring. During the transition to retail competition, many states imposed caps, freezes, or both on the rates that the incumbent utility could charge to "default" customers (those who did not sign up with a third-party competitive supplier). In some cases, these rate caps/freezes were in place for nearly ten years, during which time natural gas prices tripled. Many of the data sets used in the existing literature cover the period where the rate caps were imposed, but not when the rate caps were lifted. The retail price data may reflect these rate caps, but most studies have not modeled or otherwise adjusted for these regulatory actions. In addition, as a part of restructuring legislation, many utilities were allowed to recover "stranded costs," largely through surcharges on customer bills. These stranded cost charges thus drive a wedge between the equilibrium price (which may be modeled as part of an economic study) and the actual price. Finally, the boom in gas-fired generator construction during the early 2000s far outpaced increases in demand. The industry was thus left with a significant amount of excess capacity.

The third issue is the age-old problem of causality. Kwoka criticizes many of the existing studies for drawing causal links between restructuring and electricity prices while failing to account for other covariates which may (or may not) explain more of the variance in electricity prices. In particular, Kwoka criticizes the use of the following model to create a counterfactual set of electricity prices. Let $t_1,\ldots,t_{R-1}$ represent the series of time periods up until period $R-1$, when restructuring takes place.[9] Data on electricity prices p_{ti} and a set of explanatory variables X_{ti} are gathered, and a model of the form $p_{ti} = f(X; \boldsymbol{\beta})$ is estimated, for $i = 1,\ldots,R-1$. The

[8] Kwoka (2006), Section II.B.
[9] As Kwoka points out, assuming the existence of a single point in time dividing the pre- and post-restructuring periods is, in many cases, an oversimplification. We adopt the breakpoint assumption here for simplicity.

parameter estimate $\hat{\beta}$ is then used to produce price estimates of p_{ti}, $\widehat{p_{tR}}, \ldots, \widehat{p_{tT}}$, for the period R defining the beginning of restructuring, to period T, representing some end date. These counterfactual price estimates $\widehat{p_{tR}}, \ldots, \widehat{p_{tT}}$ are then compared to the actual prevailing prices during the same time period. While this would seem a natural method for determining how electricity prices have behaved under restructuring compared to a world where traditional regulation had simply continued, Kwoka suggests that this method may exclude valuable information from the restructuring sample period.[10]

In this paper, we have gathered a detailed firm-level data set that will allow us to address many of Kwoka's specific critiques. We now turn to a discussion of the data used in this study.

3. Data and Modeling

The existing evidence suggests that restructuring has improved production efficiency, but whether (or how much of) these efficiency gains have been passed on to consumers is much less clear. Subject to various regulatory lags, rate of return regulation should have promoted a reasonably stable relationship between prices and costs. When costs increased (as when utilities made investments for reliability or resource adequacy), regulators would allow pass-throughs to customers. Traditional methods of price regulation such as price cap regulation (RPI-X) attempted to give utilities incentives to lower costs and prices through production efficiencies (Kahn 1988).

Under restructuring, generators have generally been free to charge market-based rates, either in bilateral markets or centralized auctions run by RTOs. Cost and performance risk have been at least partially shifted to shareholders in generating companies, rather than customers of distribution utilities. By themselves, none of these factors necessarily imply that costs or prices should move one way or another. Increased wealth through higher productivity and operating efficiency should be shared between customers and generators. Higher costs (rising fuel prices, for example) will cause prices to rise.

[10] One particularly relevant example involves the behavior of natural gas prices and investment in natural gas generating units in the late 1990s and early 2000s. The counterfactual method of estimating what prices would have done had regulation simply continued implicitly assumes that the generation mix would remain roughly the same beginning in the late 1990s as it had been in previous decades. In particular, the boom in gas-fired generation would never have occurred. Another example of information that would be left out using the counterfactual method is the wide variety of state-level standards for renewable or alternative electricity generation sources.

Blumsack, Apt and Lave (2005) discuss several reasons why, *a priori*, the form of restructuring undertaken in the U.S. would increase the gap between generating costs and prices faced by consumers. The auction structure used in RTO markets pays generators based on the bid or cost of the marginal unit, whereas under regulation, each generator was effectively paid its average cost. This results in some transfer of wealth from consumers to generators, as low-cost generators are allowed to earn rents (competitive or otherwise). In addition, the total short-run system cost of serving a given amount of load is likely to rise. Another significant factor that may increase cost in the long run is the risk premium placed on non-utility generation and transmission investment. The costs of administering RTO markets are another factor, but on an average basis these have generally been small relative to total costs, and for the most part are declining on a per-unit basis.

We are left with two different price and cost effects of restructuring. If the rise in fuel prices has outweighed the efficiency gains, these increased net costs should be reflected in prices. On the other hand, the auction structure suggests a divergence between costs (particularly those of base load generators) and prices. Either way, the relevant variable is not the price of electricity, but the difference between prices and costs. This analysis thus focuses on the price-cost markup of electricity.

We collected price data covering the period 1990 through 2005 from *Average Rates and Typical Bills*, a semi-annual publication from the Edison Electric Institute (EEI). EEI collects electric rate data for a large number of investor-owned utilities. Due to high frequencies of non-reporting for some utilities, we excluded some companies from our data set. This issue will be discussed more below, but our final data set includes 71 utilities from 37 different states. 49% of the utilities in our sample underwent some form of restructuring. A list of the companies in our data set can be found in Appendix A. A highly detailed description of this data set can be found in Appendix B.

The data in the *Average Rates and Typical Bills* publication is broken up by utility and also by rate class. In this paper we confine our attention to residential, commercial, and industrial rate classes (as well as an overall average rate for each utility). The "average rates" portion of the publication reports twelve-month trailing average electricity prices. Thus, the average rates published in the summer of year t represent an average of the last six months of year $t-1$ and the first six months of year *t*. Average rates published in the winter of year *t* represent an annual average from year *t-1*. The "typical bills" portion of the publication reports single-period observations of total electric bills by utility and rate class. Thus, the "typical bill" data represents a series of snapshots, while the "average rate" data represents a moving average. In order to maintain consistency with the FERC Form 1 data on which we base our cost estimates (see below and also Appendix C), our price series consists of annual observations for each utility and rate class. The variables we construct from the *Average Rates and Typical Bills* publications are:

$Rate_{ijt}$ = Average electric rate, in cents per kilowatt-hour (kWh) for customer class i from utility j in year t. The customer classes we consider are i = {all classes, commercial, residential, industrial}. Electric rates are adjusted for inflation using the consumer price index.

$Fuel\ Cost_{ijt}$ = Fuel cost adjustment, in cents per kWh, allowed to customer class i for utility j in year t by the relevant public utility commission. Not every utility is allowed a fuel cost adjustment in every year.

CTC_{jt} = Competitive Transition Charge allowed to utility j in year t. The CTC represents the utility's stranded cost recovery allowance. The CTC is only applicable to those utilities that have undergone restructuring.

$Net\ Rate_{ijt} = Rate_{ijt} - CTC_{jt}$, for all applicable i, j, and t.

We collect data on utility-level costs from historical FERC Form 1 filings, covering the period 1994 through 2005. Each investor-owned utility is required to make a Form 1 filing with FERC each year. In more recent years (following the California power crisis and the Midwest/Northeast blackout of 2003), FERC has required utilities to fill out Form 1 on a quarterly basis. Since this is a recent reporting requirement, and since we found utilities to be inconsistent in filling out quarterly Form 1 reports, we use only the year-end Form 1 reports, which contain annual financial and system performance data. More detail on which data we extracted from the FERC Form 1 can be found in Appendix C.

Based on the data in the Form 1 reports, we construct total and average operating cost curves for each utility. The equation we use for the total cost of utility j in year t is:

Total Cost$_{i,t}$ (\$) = Reported Generation Cost$_{i,t}$ + Reported Transmission Expenditures$_{i,t}$ + Reported Distribution Expenditures$_{i,t}$ + Value of Reported Power Purchases$_{i,t}$ - Value of Reported Sales for Resale$_{i,t}$.

We highlight several points regarding the total cost equation. First, the effects of higher fuel prices on electricity production costs are reflected in both the generation cost variable (which reflects the cost of a utility producing power from its own plants) and the power purchase variable (which reflects the cost of power that utilities choose to or must buy from the market). We do not use separate variables for fuel prices, as other studies have done (such as Joskow 2006 and Taber, Chapman and Mount 2006). We did construct these variables and did test an alternate regression specification including these variables. We found that many of the fuel-mix variables were statistically insignificant and had coefficients that were hard to interpret. The regression results are included in Appendix D. In one respect, our cost variables are superior to using published fuel prices, since we are able to capture inter-utility (not just inter-regional) variations in fuel costs. Finally, the "sales for resale" variable reflects revenues earned by the utility when it sells electricity on the open market.

We then use total reported sales to end-use consumers (in all rate classes) to construct an average cost figure for each utility j in year t, as follows:[11]

Average Cost$_{i,t}$ (¢/kWh) = Total Cost$_{i,t}$ ÷ Total Reported Sales to End-Use Consumers$_{i,t}$.

Our cost variables are adjusted for inflation using the producer price index for utilities. We can now formally define our price-cost markup variable as:

Markup$_{ijt}$ = Net Rate$_{ijt}$ - Average Cost$_{i,t}$.

We tested an alternate definition of the price-cost markup representing the percentage difference of price over cost, but found that the regressions had more explanatory power when the markup was defined as the level of price over cost. Regression results from the alternate specification are included in Appendix D.

[11] Because of the nature of AC power flow, and the lack of sufficiently detailed data, it is practically impossible to construct average cost curves for each customer rate class. Such a data set would be quite valuable, but would require detailed load profile and contract information for each customer, as well as a way to trace specific electrons from the power plant to the specific customer on the distribution network.

We also collected data on annual generation mixes, and total annual generation for each utility, from EIA Form 861. Using the generation mix variables as explanatory variables seemed redundant, given how we constructed our generation cost variable from FERC Form 1 data. We did test a model specification including the generation mix variables as regressors; the output from these models is included in Appendix D. We do use the generation data to construct a measure of self-generation versus exposure to the hourly or bilateral electricity markets:

$SelfGen_{jt} = Purchased\ Power\ (MWh)_{jt} \div Generation\ (MWh)_{jt}$.

Kwoka (2006) criticizes existing studies of restructuring for taking too coarse a view regarding what constitutes "deregulation." While the limitations of our data set prevent us from representing restructuring with anything except dummy variables, we do decompose the effects of restructuring into three separate variables:

RTO_{jt} = A dummy variable equal to one for those years in which the jth utility was a member of a FERC-approved RTO.[12]

$Retail_{ijt}$ = A dummy variable equal to one for those years in which the ith customer class of the jth utility was able to choose between the traditional utility and a third-party competitive supplier for the purchase of generation services.

$Divest_{jt}$ = A dummy variable equal to one during the year(s) in which utility j divested itself of generation assets, whether by voluntary action or regulatory mandate. The variable is equal to one in all years beyond the actual date of divestiture.

We also collected data on the date of expiry of retail price caps/freezes. However, expiration of the price caps generally occurred (or will occur) beyond the end date of our sample. Thus, the price cap variables we constructed were always insignificant in our regressions.

The EEI data sets and the FERC Form 1 data sets are not without problems. First, as mentioned above, many utilities respond inconsistently or sporadically to the EEI *Average Rates and Typical Bills* survey. Most utility data series are missing at least some observations. Of the 149 U.S. utilities included in the EEI publication from 1994 to 2005,[13] we obtained 34 complete price

[12] We do not have any utilities from Texas in our sample. We include the California ISO as a FERC-approved RTO.
[13] We excluded utilities from Alaska and Hawaii, as well as utilities from outside the U.S.

data sets. The average percentage of missing observations was 21.44%, while the median percentage of missing observations was 9.09%. Four companies had a non-response rate of 96% (the maximum non-response rate we observed).

Based on the efficiency test in Griliches (1986), we determined a cutoff of 30% missing observations, before we observed a significant difference in the standard error of our regressions. We handled the missing observations in two different ways. First, we simply recorded missing observations as zeros and otherwise left the data set untouched. Second, we smoothed the gaps in the missing data using the following moving average process:

$$Rate^*_{ijt} = \frac{1}{K*}\sum_{k=1}^{K*} Rate_{ij,t-k}$$

where $Rate_{ijt}$* represents a missing observation for year t. The choice of K* had little effect on the outcome of the regressions, so we used K*=2.

In our regressions, we found that the results were not sensitive to whether we used a smoothing process to fill in the missing data or recorded missing observations as zeros. The results presented here are those for which the data set was unaltered, and missing observations were left as zeros.

We tested the EEI data sets for multiple orders of autocorrelation. Table 1 shows the Ljung-Box Q statistics for the first several orders of autocorrelation. We find evidence of first-order autocorrelation in the time series of electric rates in each customer class. This is confirmed by a simple Breusch-Godfrey test statistic of 10.5, compared to a χ^2_1 critical value of 3.8 (for α=0.95).

	Q-Statistics			
Order of Autocorrelation (*s*)	**Average Markup**	**Residential Markup**	**Commercial Markup**	**Industrial Markup**
1	***5.91***	***5.66***	***6.67***	***7.05***
2	4.31	4.02	5.15	5.92
3	4.75	5.37	6.89	7.36

Table 1: Ljung-Box Q Statistics for price-cost markups by customer class. Entries in bold italics signify that the null hypothesis of no autocorrelation at the specified order can be rejected at the 5% significance level.

Care must also be taken when interpreting or using the FERC Form 1 data. While the data set is highly detailed (and thus, for better or for worse, is the best data source of its kind for U.S. utilities), not all companies use the same accounting standards in their Form 1 filings. Further, the accounting standards may change from year to year for a given utility. In particular, utilities can differ amongst each other, and over time, regarding what costs are allocated to operations and maintenance (O&M) expenditures, and what costs are considered capital expenditures (and therefore can go into the rate base).[14]

The definition of costs used in this paper includes reported operating and maintenance costs but not capital investment costs. It is possible that some utilities in some years re-allocated costs from O&M to capital in order to increase their rate-base revenues in years of high market prices or uncertainty. This will, in general, reduce the explanatory power of our regression models by increasing the error term. Assuming that the variation in cost allocation among utilities over time is a mean-zero normal random variable, our regression model will take the general form:

$$y* = \boldsymbol{X}'\boldsymbol{\beta} + \boldsymbol{\varepsilon}$$

$$y = y* + u$$

where u and ε are both the standard white-noise error terms (Greene 2002).

Assuming that all of the variables in X are known with certainty, then our model becomes an errors-in-variables model, but only in the *dependent* variable. Since $y* = y - u$, we then get a regression equation of the form:

$$y* = \boldsymbol{X}'\boldsymbol{\beta} + \boldsymbol{\varepsilon} + u$$

This equation can be estimated using standard techniques.

[14] Personal communication (via e-mail) with Bruce Edelston, November 12, 2007.

4. Results

In general, we found a persistent gap between the price-cost markups for regulated and restructured utilities, as shown in Figure 2. The figure is somewhat simplistic in that it defines a restructured utility as one that underwent at least one form of restructuring (wholesale competition, retail competition, or divestiture) between 1994 and 2005. Figure 2 in and of itself does not say very much about the effect of restructuring; rather it suggests some fundamental differences in utilities that restructured versus those that did not. However, the difference between the markups for restructured utilities and regulated utilities has increased over time, particularly beginning in 1998 (when California and Pennsylvania became the first states to embrace modern restructuring). The difference in markups between restructured and regulated utilities also became more pronounced beginning in 2001. This difference is shown graphically in Figure 3.

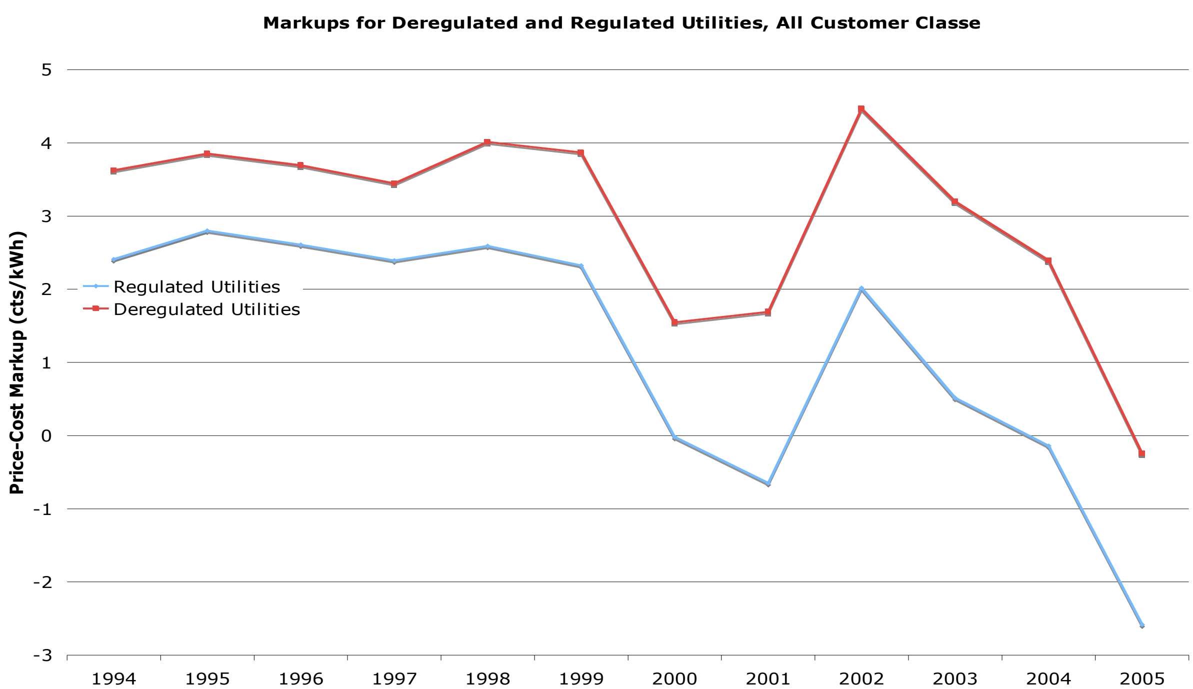

Figure 2. Price-cost markups for all customer classes. In this figure, utilities are judged to be "deregulated" if at any point in our sample the utility was subject to asset divestiture, retail competition, or was located within an RTO footprint.

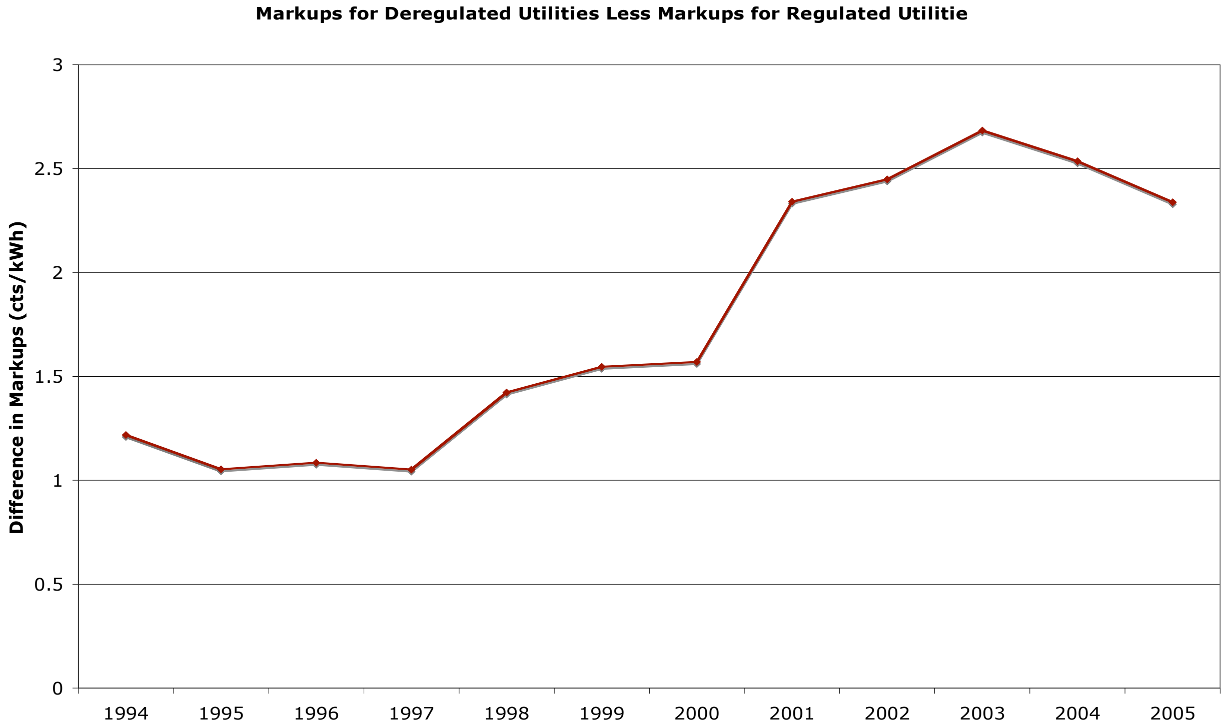

Figure 3. The difference in price-cost markups for deregulated vs. regulated utilities, all customer classes. In this figure, utilities are judged to be "deregulated" if at any point in our sample the utility was subject to asset divestiture, retail competition, or was located within an RTO footprint.

Since the differences in markups are not constant over time, we investigate utility-specific, market, and regulatory factors that could explain why the price-cost markups have increased much more for restructured utilities than for utilities that remained traditionally regulated. We estimate the following regression equation, for all customer classes i = {all classes together, residential, commercial, and industrial}, all utilities j, and all years t between 1994 and 2005.

$$Markup_{ijt} = \beta_{i0} + \beta_{i1}(Year) + \beta_{i2}(RTO\ Dummy_{ijt}) + \beta_{i3}(Retail\ Competition\ Dummy_{ijt}) + \beta_{i4}(Divestiture\ Dummy_{ijt}) + \beta_{i5}(RTO \times Retail_{ijt}) + \beta_{i6}(RTO \times Divestiture_{ijt}) + \beta_{i7}(Ratio\ of\ Purchases\ to\ Generation_{ijt}) + \beta_{i8}(Fuel\ Cost\ Adjustment_{ijt}) + \varepsilon_{ijt}$$

We included the interaction terms $RTO \times Retail_{ijt}$ and $RTO \times Divestiture_{ijt}$ to capture the effects of utilities that undertook two of the components of restructuring, but perhaps not a third (in our sample, there were no utilities that embraced retail competition and divested, but did not join an

RTO). We estimate separate models for each rate class, using Feasible Generalized Least Squares (Greene 2002), correcting for heteroscedasticity and first-order autocorrelation.

Tables 2 through 5 show the estimated parameters for each of the four models we estimated.

Dependent variable: Average Markup (Level)

Variable	Coefficient	T-Statistic
Constant	***3.40***	21.86
Time	***-0.39***	-11.86
RTO Dummy	0.29	0.41
Retail Dummy	***2.51***	2.97
Divestiture Dummy	***1.07***	4.46
RTO*Retail	***-2.43***	-2.28
RTO*Divestiture	0.47	0.63
Ratio of Purchases to Generation	***9*10^-4***	-6.15
Fuel Cost Adjustment	0.02	0.25
Regression Std. Error	7.09	
Regression Adjusted R^2	0.42	

Table 2: Results for all rate classes together. Parameter estimates in bold italics are statistically significant at the 5% level.

Dependent variable: Residential Markup (Level)

Variable	Coefficient	T-Statistic
Constant	***4.76***	24.96
Time	***-0.38***	-10.33
RTO Dummy	0.93	1.42
Retail Dummy	***2.70***	3.23
Divestiture Dummy	***1.53***	5.36
RTO*Retail	***-2.75***	-2.67
RTO*Divestiture	-0.24	-0.31
Ratio of Purchases to Generation	***5*10^-4***	-3.13
Fuel Cost Adjustment	0.02	0.19
Regression Std. Error	8.32	
Regression Adjusted R^2	0.39	

Table 3: Results for the residential rate class. Parameter estimates in bold italics are statistically significant at the 5% level.

Dependent variable: Commercial Markup (Level)

Variable	Coefficient	T-Statistic
Constant	***2.34***	14.77
Time	***-0.08***	-2.33
RTO Dummy	1.22	1.57
Retail Dummy	1.68	1.95
Divestiture Dummy	***1.25***	5.16
RTO*Retail	-2.15	-1.88
RTO*Divestiture	0.10	0.12
Ratio of Purchases to Generation	***8*10^-4***	-4.72
Fuel Cost Adjustment	0.10	1.24
Regression Std. Error	8.32	
Regression Adjusted R^2	0.39	

Table 4: Results for the commercial rate class. Parameter estimates in bold italics are statistically significant at the 5% level.

Dependent variable: Industrial Markup (Level)

Variable	Coefficient	T-Statistic
Constant	***3.52***	17.90
Time	-0.01	-0.23
RTO Dummy	***2.13***	2.59
Retail Dummy	***1.79***	2.03
Divestiture Dummy	***1.73***	5.78
RTO*Retail	***-2.50***	-2.18
RTO*Divestiture	-0.78	-0.80
Ratio of Purchases to Generation	0.00	-1.53
Fuel Cost Adjustment	0.11	1.07
Regression Std. Error	8.99	
Regression Adjusted R^2	0.35	

Table 5: Results for the industrial rate class. Parameter estimates in bold italics are statistically significant at the 5% level.

The regression results in Tables 2 through 5 demonstrate a more complex relationship between electricity prices and restructuring than in previous studies. First, and perhaps most interestingly, the various customer classes each appear to have been affected differently by restructuring. Overall, those utilities that divested themselves of generation and had their service territory opened up to retail competition saw their prices rise, but RTOs themselves appear to have had little impact (Table 2). Note also in Table 2 that the interaction variable for RTO membership and retail competition is negative, indicating that retail competition in and of itself is associated with higher price-cost markups, while the combination of RTO membership and retail competition is associated with lower price-cost markups (though the combined effect is smaller than the effect of retail competition alone). This would seem to suggest some colinearity among the RTO and retail competition dummy variables. We performed a sensitivity analysis where we removed the interaction variable. A chi-squared test on the regression standard error with and without the interaction variable suggests that removing this variable would introduce some omitted variables bias.

For both residential and industrial customers, the variables for retail competition and divestiture are positive and statistically insignificant. The RTO dummy variable is positive and statistically significant for industrial customers, but not for residential customers. Industrial customers were thought to be the biggest potential beneficiaries of restructuring, so these customers, on average, transitioned away from regulated electric rates faster than the other two classes. Some were able to sign advantageous contracts prior to the beginning of restructuring, but which expired coincidentally with the rise in natural gas prices (Apt 2005). Overall, the restructuring variables have the least explanatory power (in the sense that most are statistically insignificant at the 5% level) for the commercial rate class. Part of this may be due to the heterogeneity inherent in the commercial rate class. This class of customer includes very small businesses (which may consume less electricity than some homes) and large office buildings.[15]

The fuel cost adjustment variable has a parameter estimate that is small in magnitude and statistically insignificant for all four rate classes. The ratio of purchases to generation is statistically significant in all but the regression for the industrial rate class. However, the

[15] Earlier data in the EEI publications would allow us to separate small and large commercial users. More recent data, however, groups all commercial users into a single category.

magnitude of the estimated parameter is quite small. We thus conclude that these two variables have, at best, a marginal impact on price-cost markups for electric utilities.

5. Concluding Remarks

The question of whether electricity restructuring has lowered prices for consumers has been highly contentious. But the question is an important one – if consumers have not seen lower prices, then how are consumers well-served by moving forward (however slowly or erratically) with further restructuring efforts? If the point of restructuring was not to lower costs and prices, then what metrics should policymakers use to evaluate whether the restructuring is working as intended?

Existing studies of electricity restructuring and electricity prices offer no clear answer. By and large, studies by consultants and industry groups have been favorable towards restructuring, while studies by academics have been more pessimistic. Further, given the excellent critiques in Kwoka (2006), it is not clear whether or how much any of the existing results should be trusted. This paper takes a somewhat different approach than in previous work. We examine how price-cost markups have changed with restructuring, rather than looking at prices themselves (or changes in prices). The logic is simple: there is solid evidence that restructuring has contributed to an increase in productivity and efficiency in electric power generators. The body of evidence on whether these productivity gains have been passed on to consumers is less solid, but overall does not suggest that consumers have experienced windfall gains.

Rather than examining consumer prices *per se*, we examine differences between reported average prices and average costs for investor-owned utilities that have undergone restructuring and those that have remained traditionally regulated. Using a detailed utility-level data set to measure prices and costs for different rate classes, we find evidence that price-cost margins are significantly higher in regions of the U.S. that have adopted some form of restructuring. Our regression models estimate that, on average, the introduction of retail competition has increased price-cost markups by approximately 2.5 cents per kWh. Utility divestiture has increased price-cost markups by slightly more than 1 cent per kWh. Overall, simply joining an RTO has had little effect on price-cost markups, although the combination of RTO membership and retail competition appears to dampen the increase in price-cost margins. Our finding that price-cost markups have gone up with restructuring suggests that most of the gains from restructuring have, thus far, gone to producers rather than consumers. This may be true for a number of reasons. Rate caps and freezes in many restructured states have introduced market distortions on the retail side. The reallocation of risks and rewards suggests that firms in the electricity market will demand higher profits in return for shouldering more of the risk of bad investments or management practices.

A natural question at this point is: if generators are earning higher revenues in the RTO auction markets, and if they have lowered their costs by becoming more efficient, where is the money going? One explanation is provided by Bodmer (2006), who demonstrates that share prices of low-cost generators operating in restructured markets have increased dramatically since the late 1990s. Another explanation may be that generating firms are demanding higher returns in exchange for being forced to take on more risk. Given that our data set consists of distribution utilities that are still regulated in some fashion, it is perhaps difficult to square the risk explanation with our particular sample. A third possibility is that firms are able to exercise market power in ways that the RTO market monitors do not detect.

We have improved on previous work, and addressed some of the critiques in Kwoka (2006) by using a firm-level data set, and explicitly accounting for firm-specific fuel price increases, fuel cost adjustments, and stranded cost recovery. We also are able to decompose "restructuring" into three more specific variables. But our study still has some important limitations. The first is that we are not able to properly capture the effects of regulator-mandated price caps for distribution utilities during the transition period from regulation to competition. Where rate caps have come off, the future path of electric prices is uncertain, due in large part to political pressures. Where rate caps have not come off, they will not be lifted for several years. A second limitation is that our data set only includes a sample of investor-owned utilities. We are thus not able to capture any of the effects on municipal, cooperative, or government-owned utilities. A third issue is that the FERC Form 1 data we use to estimate costs likely suffers from significant variations in accounting practices. This does not affect the statistical properties of our estimators, but does make the error terms in our regressions larger than they otherwise would be.

Finally our data does not capture any of the technological changes taking place in the electric power industry, particularly with regard to distributed generation and microgrids.

To summarize, we find that utilities that have undergone restructuring display significantly higher price-cost markups than utilities that remained traditionally regulated. The combination of introducing retail competition into an electric utility's operating territory and divestiture of that utility's generating assets has increased costs, but has increased prices even more. In particular, we find an average difference of 2 to 3 cents per kWh between prices and costs that is explained by restructuring rather than by increases in fuel prices. We conclude that restructuring has been beneficial to companies that restructured, but the benefits have not reached consumers.

Appendix A: List of Companies

Table A.1 contains a list of utility companies that were used in the data set for this study. Some utilities in our sample operate in multiple states, but sufficient data was only available for one or some of those states. The state(s) for which we had sufficient data are shown in the table. Also shown for each utility is the percentage of data points missing from the EEI *Average Rates and Typical Bills* data set.

Company Name	State	Missing Data (%)	Company Name	State	Missing Data (%)
Alabama Power Company	AL	3.0%	Northern Indiana Public Service Company	IN	33.3%
Appalachian Power Company	TN	0.0%	NorthWestern Corporation	MT	0.0%
Arizona Public Service Company	AZ	30.3%	Orange and Rockland Utilities, Inc.	NY	3.0%
Baltimore Gas and Electric Company	MD	0.0%	Otter Tail Corporation	MN	0.0%
Bangor Hydroelectric Company	ME	18.2%	Pacific Gas and Electric Company	CA	3.0%
Central Illinois Light Company	IL	15.2%	PacifiCorp	OR	0.0%
Central Vermont Public Service Corporation	VT	6.1%	PECO Energy Company	PA	9.1%
Commonwealth Edison Company	IL	0.0%	Pennsylvania Electric Company	PA	15.2%
Connecticut Light and Power Company	CT	9.1%	Portland General Electric Company	OR	3.0%
Consumers Energy Company	MI	0.0%	Potomac Edison Company	MD	3.0%
Dayton Power and Light	OH	27.3%	Potomac Electric Power Company	DC	3.0%
Detroit Edison Company	MI	0.0%	Public Service Company of Colorado	CO	9.1%
Edison Sault Electric Company	MI	12.1%	Public Service Company of New Hampshire	NH	0.0%
El Paso Electric Company	TX	12.1%	Public Service Company of New Mexico	NM	18.2%
Empire District Electric Company	AR	0.0%	Public Service Company of Oklahoma	OK	0.0%
Entergy Arkansas	AR	0.0%	Public Service Electric and Gas Company	NJ	15.2%
Entergy Louisiana	LA	6.1%	Puget Sound Energy	WA	0.0%
Entergy Mississippi	MS	36.4%	Rochester Gas and Electric Corporation	NY	3.0%
Entergy New Orleans	LA	9.1%	San Diego Gas and Electric Company	CA	12.1%
Georgia Power Company	GA	0.0%	South Beloit Water, Gas, and Electric	IL	15.2%
Green Mountain Power Corporation	VT	12.1%	South Carolina Electric and Gas Company	SC	9.1%
Gulf Power Company	FL	6.1%	Southern California Edison Company	CA	9.1%
Idaho Power Company	ID	0.0%	Southwestern Electric Service Company	AR	21.2%
Illinois Power	IL	27.3%	Southwestern Public Service Company	KS	6.1%
Indianapolis Power and Light Company	IN	6.1%	Superior Water, Power and Light Company	WI	21.2%
Interstate Power and Light	IL	21.2%	Tampa Electric Company	FL	0.0%
Kansas City Power and Light Company	KS	0.0%	Texas Utilities	TX	24.2%
Kentucky Utilities Company	KY	3.0%	The United Illuminating Company	CT	0.0%
Madison Gas and Electric Company	WI	3.0%	Tucson Electric Power Company	AZ	6.1%
Metropolitan Edison Company	PA	15.2%	Unitil	NH	3.0%
MidAmerican Energy Company	IL	21.2%	Upper Peninsula Power Company	MI	0.0%
Mississippi Power Company	MS	15.2%	West Penn Power Company	PA	3.0%
Monongahela Power Company	OH	3.0%	Western Massachusetts Electric Company	MA	12.1%
Nevada Power Company	NV	0.0%	Wisconsin Public Service Corporation	WI	0.0%
New York State Electric & Gas Corporation	NY	21.2%			

Table A.1. List of electric utilities considered in this study.

Appendix B: Detailed Description of the EEI Data

Data collection procedures and description of the EEI report dates

EEI publishes the Typical Bill and Average Rate data twice yearly – the winter edition (which is published in April) reports on typical bills based on rates in effect January 1 and the summer edition (which is published in October) reports on typical bills based on rates in effect July 1. The Typical Bill data represents a snapshot of the rates in effect January 1 and July 1. Thus, the Typical Bill data for Winter 1998 would represent rates in effect January 1, 1998, and the Typical Bill data for Summer 1998 would represent rates in effect July 1, 1998. A time series of Typical Bill data would thus represent a series of snapshots through time.

Data for the Average Rate publication carries a different significance. Each edition of the Average Rate data shows the average rates (calculated using total sales and total revenue as reported by each company) over the past year starting with the date targeted by the individual report. Thus, the Average Rate data for Winter 1998 represents total sales and revenue (and average prices) during calendar year 1997. The Average Rate data for Summer 1998 represents total sales and revenue (and average prices) for the first six months of 1998 and the last six months of 1997. A time series of Average Rate data would thus represent a moving average of rates over time. This distinguishes the Average Rate data from a similar data source put out by EIA.

A difference between the EEI Average Rate data and the EIA data, particularly since restructuring, is: (a) recent EEI Average Rate data is unbundled, showing the generation, delivery, and (if applicable) CTC components, and (b), EIA data may contain a mix of default service utilities and competitive suppliers, whereas EEI Average Rate data only represents the investor-owned default service utilities. The EEI data is thus consistent over time, whereas the universe of respondents to the EIA data survey has changed significantly with restructuring.

Summer/Winter Differentials

The EEI Typical Bill data for some editions contains columns RES_DIFF, COMM_DIFF, and IND_DIFF. These are indicator variables for each company showing whether that company has a different rate structure in the summer and in the winter. These columns do not appear in the data series for all editions of the Typical Bill data.

Fuel Cost Adjustments

The fuel cost adjustments (FCA) represent positive or negative differentials to every kilowatt-hour used, and can vary over rate classes. In the Typical Bill data published by EEI, there is an FCA reported for each company. While these are disaggregated from the rest of the bill, the FCA is included in the Typical Bill data for each customer class. That is, if the FCA for a given company was $1 and a certain bill was $14, the total bill is $14 and not $15 ($14 + $1 for the FCA). The bill without the FCA would be $13.

An FCA of zero for a specific company does not necessarily mean that the company does not have a fuel adjustment clause in place. If the FCA for a given state or company is consistently zero for a large number of years, then it is likely that the given state or company does not include fuel cost adjustments in its rate settlements, but not 100% certain.

Demand charges

The data collected by EEI for the Typical Bill and Average Rate data series do not include a disaggregated demand charge, but the monetary effect of the demand charge does show up in the data. In the Average Rate data, companies report total sales and total revenue, which includes demand charges. Thus, the average rates, in cents per kilowatt-hour, also have demand charges rolled in. The dollar figures in the Typical Bill data also include total payments attributable to demand charges.

Documentation of Average Rate and Typical Bill Data Sets

This section describes the data taken from the EEI publications *Average Rates* and *Typical Bills.* It is a straightforward description of each data column included in the publication.

1. Average Rates – contains information from the EEI Average Rates publication. The publication comes out twice per year, with data on average rates by customer class (commercial, residential, and industrial). The data at time *t* reflects a volume-weighted average price for the previous twelve months.

Column Headings:

Company Name – shows the name of the company

State – shows the state associated with the company and price data (some companies operate in multiple states; these companies will have multiple entries, one for each state in which they operate).

Date – shows the date of the report

Data – shows the time frame covering the twelve-month averaging

Rate Portion – shows whether the average price represents a bundled rate (including generation, transmission, delivery, and demand charges) or a specific portion of the bundled rate. Prior to deregulation, utilities were vertically integrated and all price data is bundled. Following deregulation, some companies have split their data submission into generation, transmission, delivery, and stranded-cost charges.

Total – shows the average rate (cents per kWh) for all customers

Residential – shows the average rate (cents per kWh) for the residential class

Commercial – shows the average rate (cents per kWh) for the commercial class

Industrial – shows the average rate (cents per kWh) for the industrial class

2. Typical Bills – contains information from the EEI Typical Bills publication. The publication comes out twice per year, with data on total expenditures by utility and customer class. The data at time t represents total expenditures by the average customer at that time – the typical bill data does not represent a moving average like the Average Rate data set.

Column Headings:

Date – shows the date of the report. Winter reports are issued in January and Summer reports are issued in July.

Rate Component – shows whether the average price represents a bundled rate (including generation, transmission, delivery, and demand charges) or a specific portion of the bundled rate. Prior to deregulation, utilities were vertically integrated and all price data is bundled. Following deregulation, some companies have split their data submission into generation, transmission, delivery, and stranded-cost charges.

State Code – a numerical code for each state.

State – shows the state associated with the company and price data (some companies operate in multiple states; these companies will have multiple entries, one for each state in which they operate).

Region – shows the region associated with the company and price data.

Company Code – a numerical code for each company.

Company – shows the name of the company.

Residential FCA – shows the amount of the residential fuel price adjustment (in dollars) charged by the utility and allowed by the public utility commission. The FCA is interpreted as a differential from the previous period's data. If the FCA is x at time t, that says that x amount of the difference between the total expenditures at time t and time $t - 1$ is attributable to fuel cost adjustments. Any remaining difference is attributable to other factors.

Residential Differential – shows whether the company is allowed to charge differentiated rates to residential customers in the summer and the winter. The variable is binary – an entry of 1 indicates that the utility is allowed to charge differentiated rates to residential customers and an entry of 0 indicates that the utility is not allowed to charge differential rates to residential customers.

Commercial FCA – shows the amount of the commercial fuel price adjustment (in dollars) charged by the utility and allowed by the public utility commission. The FCA is interpreted as a differential from the previous period's data. If the FCA is x at time t, that says that x amount of the difference between the total commercial expenditures at time t and time $t - 1$ is attributable to fuel cost adjustments. Any remaining difference is attributable to other factors.

Commercial Differential – shows whether the company is allowed to charge differentiated rates to commercial customers in the summer and the winter. The variable is binary – an entry of 1 indicates that the utility is allowed to charge differentiated rates to commercial customers and an entry of 0 indicates that the utility is not allowed to charge differential rates to commercial customers.

Industrial FCA – shows the amount of the industrial fuel price adjustment (in dollars) charged by the utility and allowed by the public utility commission. The FCA is interpreted as a differential from the previous period's data. If the FCA is x at time t, that says that x amount of the difference between the total industrial expenditures at time t and time $t - 1$ is attributable to fuel cost adjustments. Any remaining difference is attributable to other factors.

Industrial Differential – shows whether the company is allowed to charge differentiated rates to industrial customers in the summer and the winter. The variable is binary – an entry of 1 indicates that the utility is allowed to charge differentiated rates to industrial customers and an entry of 0 indicates that the utility is not allowed to charge differential rates to industrial customers.

The next selection of columns shows the total expenditures, in total dollars, for a typical or average customer in a wide variety of rate classes.

Residential Z – shows total expenditures for a residential consumer using up to Z kWh per month.

Residential Hot Water Heating Z – shows total expenditures for a residential consumer with electric hot water heating using up to Z kWh per month.

Residential All Electric Z – shows total expenditures for a residential consumer with all electric appliances (heat, cooking, etc) using up to Z kWh per month.

Commercial Y x Z – shows total expenditures for a commercial customer with a peak demand of up to Y kW and a total usage of up to Z kWh per month.

Industrial Y x Z – shows total expenditures for an industrial customer with a peak demand of up to Y kW and a total usage of up to Z MWh per month.

We note that consumption for industrial customers is in MWh and consumption for commercial and residential customers is in kWh.

Appendix C: Detailed Description of the FERC Form 1 Data

The FERC Form 1 is a combination operational statement and financial statement that every investor-owned utility (IOU) must submit to the Federal Energy Regulatory Commission (FERC) on a quarterly basis. Merchant generators (companies that own generation but sell it only to the market and do not have any customers), federal utilities, and municipal utilities do not have to fill out the FERC Form 1. In our study, we use annual (end-of-year) FERC Form 1 data, which contains cumulative data covering the entire calendar year. In the course of gathering data for our study, we found that companies were inconsistent in whether and how they filed their quarterly FERC Form 1 reports. Any company that did not file an end-of-year FERC Form 1 during our sample period was excluded from our sample.

The following describes the data extracted from the FERC Form 1 for the purposes of this study:

Sales to Ultimate Consumers: The total amount of electric energy (MWh) sold to end-use customers of a given utility. This figure does not include wholesale purchases, sales, or exchanges. The source for this data is page 300, line item 10 of the FERC Form 1.

Net Generation: Total electric energy (MWh) produced by a given utility, net of any electric energy required to operate generating facilities. This output data is gathered from multiple sources within the FERC Form 1, where applicable. Data for large steam generators is from page 402. Data for large hydro generators is from page 406. Data from pumped hydro generators is from page 408. Data from small generators is from page 410.

Sales for Resale: The total amount (MWh) and nominal dollar value of all electric energy sold on the wholesale market (including exchanges and bilateral deals). The source for this data in dollar terms is page 300, line item 11 of the FERC Form 1. The source for this data in quantity terms is page 301, line item 11.

Purchased Power: The total amount (MWh) and nominal dollar value of all electric energy purchased from the wholesale market (including exchanges and bilateral deals). The source for this data in dollar terms is page 321, line item 76 of the FERC Form 1. The source for this data in quantity terms is page 327.

Generation Cost: Total reported expenditures, in nominal dollars, on the generation of electric energy. The cost figures we use include operations and maintenance (including reported fuel purchases) but not depreciation. The source for this data is page 320, line item 80 of the FERC Form 1.

Transmission Cost: Total reported expenditures, in nominal dollars, on the bulk transmission assets of a given utility. This figure includes annual investment, operations and maintenance costs. It does not include expenditures related to congestion payments, wheeling charges, or other transmission expenditures incurred as a direct result of wholesale purchases. The source for this data is page 320, line item 100 of the FERC Form 1.

Distribution Cost: Total reported expenditures, in nominal dollars, on the distribution assets of a given utility. The source for this data is page 320, line item 126 of the FERC Form 1.

Appendix D: Alternate Model Specifications

In this Appendix, we show regression results for some alternate specifications of our model in Section 4.

D.1 Percentage Price-Cost Markup

The regression results shown in this paper use a "levels" definition of the price-cost markup – that is, the markup is defined as:

$Markup_{ijt} = Net\ Rate_{ijt} - Average\ Cost_{i,t}$,

where $Net\ Rate_{ijt}$ indicates that the competitive transition charge (CTC), if applicable, has been subtracted from the utility's rate reported in the *Average Rates and Typical Bills* publication. An alternate definition of the price-cost markup would be one similar to the Lerner Index, but using average, rather than marginal, rates and costs:

$\%Markup_{ijt} = (Net\ Rate_{ijt} - Average\ Cost_{i,t}) \div Net\ Rate_{ijt}$.

Tables D.1 through D.4 show the regression results using the percentage markup for each customer class as the dependent variable, rather than the level markup. In general, the formulation based on the percentage markup was found to have little explanatory power, compared to the formulation discussed in the main body of this paper.

Dependent variable: All Classes Markup (Percentage)

Variable	Coefficient	T-Statistic
Constant	0.97	22.33
Time	-0.09	-15.21
RTO Dummy	0.02	0.16
Retail Dummy	0.21	2.47
Divestiture Dummy	0.09	1.52
RTO*Retail	-0.12	-0.84
RTO*Divestiture	-0.02	-0.19
Ratio of Purchases to Generation	0.00	-3.13
Fuel Cost Adjustment	0.00	0.19
Regression Std. Error	0.233	
Regression Adjusted R^2	0.27	

Table D.1. Regression results for all rate classes, with percentage markup as the dependent variable.

Dependent variable: Residential Markup (Percentage)

Variable	Coefficient	T-Statistic
Constant	1.40	24.15
Time	-0.11	-13.91
RTO Dummy	-0.05	-0.43
Retail Dummy	0.19	1.75
Divestiture Dummy	0.15	2.04
RTO*Retail	-0.06	-0.40
RTO*Divestiture	-0.10	-0.70
Ratio of Purchases to Generation	0.00	-1.63
Fuel Cost Adjustment	-0.01	-0.48
Regression Std. Error	0.36	
Regression Adjusted R^2	0.28	

Table D.2. Regression results for the residential rate class, with percentage markup as the dependent variable.

Dependent variable: Commercial Markup (Percentage)

Variable	Coefficient	T-Statistic
Constant	0.84	19.85
Time	-0.05	-8.46
RTO Dummy	0.05	0.38
Retail Dummy	0.15	1.60
Divestiture Dummy	0.13	2.42
RTO*Retail	-0.11	-0.66
RTO*Divestiture	-0.07	-0.47
Ratio of Purchases to Generation	0.00	-4.29
Fuel Cost Adjustment	0.00	0.28
Regression Std. Error	0.23	
Regression Adjusted R^2	0.22	

Table D.3. Regression results for the commercial rate class, with percentage markup as the dependent variable.

Dependent variable: Industrial Markup (Percentage)

Variable	Coefficient	T-Statistic
Constant	1.24	21.57
Time	-0.06	-7.71
RTO Dummy	0.03	0.22
Retail Dummy	0.09	0.74
Divestiture Dummy	0.18	2.50
RTO*Retail	0.00	-0.03
RTO*Divestiture	-0.19	-1.13
Ratio of Purchases to Generation	0.00	-2.47
Fuel Cost Adjustment	0.00	0.18
Regression Std. Error	0.36	
Regression Adjusted R^2	0.25	

Table D.4. Regression results for the industrial rate class, with percentage markup as the dependent variable.

D.2. Inclusion of fuel-mix variables

We also ran our regressions including some measures of the fuel mix of each utility. We note that our price-cost markup variable already incorporates the utility-level reported fuel purchase costs (as in FERC Form 1). Since the influence of fuel prices is already in our regressions, it is not clear what (if any) additional information is provided by the fuel mix variables. The parameter estimates for the fuel mix are often statistically insignificant and difficult to interpret. We include regression results with these fuel mix variables for the sake of completeness. Table D.5 includes regression results with the level of the price-cost markup as the dependent variable, while Table D.6 includes regression results with the percentage markup of price over cost as the dependent variable.

	Average Markup		Residential Markup		Commercial Markup		Industrial Markup	
Variable	*Coef.*	*T-Stat.*	*Coef.*	*T-Stat.*	*Coef.*	*T-Stat.*	*Coef.*	*T-Stat.*
Constant	5.33	11.78	6.39	13.38	5.66	11.89	3.45	7.70
Time	-0.35	-11.18	-0.32	-9.27	-0.35	-9.98	-0.38	-11.96
RTO Dummy	1.34	1.60	2.29	2.87	1.62	1.78	-0.32	-0.39
Retail Dummy	3.18	3.78	3.74	4.92	3.31	4.05	2.39	2.56
RTO*Retail	-2.25	-2.03	-2.48	-2.40	-2.62	-2.32	-1.27	-1.12
Divestiture Dummy	1.30	4.99	2.04	6.96	1.53	5.70	0.89	3.75
RTO*Divestiture	-1.45	-1.45	-2.86	-2.90	-2.08	-2.05	-0.53	-0.57
Ratio of Purchases to Generation	-2.18	-4.52	-2.42	-4.88	-2.33	-4.71	-1.86	-3.84
Coal Generation (%)	-1.24	-3.29	-1.23	-3.04	-1.17	-2.97	-0.95	-2.48
Gas Generation (%)	0.28	0.67	0.13	0.30	0.49	1.10	0.26	0.66
Nuke Generation (%)	0.75	2.31	1.30	3.82	0.77	2.40	0.28	0.97
Hydro Generation (%)	-0.74	-1.80	-0.70	-1.50	-0.55	-1.26	-0.88	-2.20
Oil Generation (%)	-0.28	-0.66	-0.63	-1.28	-0.42	-0.90	-0.28	-0.68
Fuel Cost Adjustment	-0.05	-0.41	-0.07	-0.60	-0.08	-0.72	-0.10	-0.76
R^2	0.41		0.39		0.4		0.35	

Table D.5. Regression results including utility-level fuel mix variables, with the level of the price-cost markup as the dependent variable.

	Average Markup		Residential Markup		Commercial Markup		Industrial Markup	
Variable	*Coef.*	*T-Stat.*	*Coef.*	*T-Stat.*	*Coef.*	*T-Stat.*	*Coef.*	*T-Stat.*
Constant	1.17	5.54	1.56	6.22	1.31	6.40	0.62	4.02
Time	-0.10	-5.77	-0.12	-5.72	-0.11	-6.03	-0.08	-5.75
RTO Dummy	0.71	1.66	0.81	1.70	0.71	1.67	0.47	1.45
Retail Dummy	1.02	1.46	1.26	1.59	1.03	1.49	0.66	1.26
RTO*Retail	-0.51	-0.73	-0.57	-0.72	-0.53	-0.77	-0.29	-0.56
Divestiture Dummy	-0.01	-0.05	0.10	0.66	0.04	0.27	-0.04	-0.40
RTO*Divestiture	-0.86	-1.56	-1.13	-1.82	-0.94	-1.70	-0.62	-1.47
Ratio of Purchases to Generation	-0.36	-2.27	-0.56	-3.07	-0.44	-2.83	-0.16	-1.36
Coal Generation (%)	-0.21	-2.40	-0.23	-2.23	-0.20	-2.14	-0.16	-2.21
Gas Generation (%)	-0.14	-0.95	-0.16	-0.89	-0.05	-0.33	-0.11	-0.95
Nuke Generation (%)	0.29	2.29	0.43	2.79	0.27	2.09	0.15	1.57
Hydro Generation (%)	-0.35	-1.79	-0.36	-1.58	-0.31	-1.55	-0.32	-2.10
Oil Generation (%)	0.05	0.28	-0.04	-0.20	0.03	0.16	0.06	0.39
Fuel Cost Adjustment	0.12	1.12	0.12	1.05	0.09	0.99	0.09	1.05
R^2	0.26		0.28		0.26		0.26	

Table D.6. Regression results including utility-level fuel mix variables, with the percentage markup of price over cost as the dependent variable.

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