Deregulation, Market Power, and Prices: Evidence from the Electricity Sector*

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Abstract

When deciding whether to introduce market-based prices into a regulated market, a regulator faces the following tradeoff: profit incentives may reduce costs through the more efficient allocation of resources, but the presence of market power may lead to increased markups. We use a detailed dataset on electricity transactions to investigate the impact of market-based deregulation in the context of the U.S. electricity sector. We find that the increase in markups dominates despite modest efficiency gains, leading to higher prices to consumers. Deregulation does not necessarily lead to lower prices to consumers. A consumer-oriented regulator may prefer to regulate rates to be consumer friendly, rather than let prices be subject to market power.

Keywords: Deregulation, Market Power, Markups, Prices, Electricity JEL Classification: L51, L94, D43, L13

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1 Introduction

Organizations that make large investments in broadly-used infrastructure are often subject to special regulation. These organizations are typically characterized as natural monopolies, and regulation has been used to ensure the fair provision of services in the absence of competition. Industries such as electricity, airlines, telecommunications, and railroads have been subject to strict controls by governmental agencies, including the determination of prices.

Over the past 50 years, many of these industries have been reshaped by deregulation efforts. A common element of these efforts has been the introduction of competition and marketdetermined prices, with the goal of lowering prices to consumers. Though these efforts are largely considered to have been successful, we have relatively limited evidence of the effects of deregulation on prices.

In fact, the impact of deregulation on prices is theoretically ambiguous. Market-based prices provide an incentive for profit-maximizing firms to reduce costs, but firms also have an incentive to increase markups in the presence of market power. When cost efficiencies are outweighed by the increase in markups, market-based prices can be higher than regulated rates. Thus, a regulator faces a tradeoff between the more efficient allocation of resources and the exercise of market power. A consumer-oriented regulator may prefer a regulated monopoly over markets that allow for profit-maximizing behavior.

In this paper, we study this tradeoff in the context of the deregulation of the U.S. electricity sector, which began in the 1990s. Deregulation efforts included the introduction of marketbased prices and restructuring measures to introduce competition into the upstream generation market and the downstream retail market. Over 20 years later, we have yet to fully understand the consequences of this effort (Bushnell et al., 2017). Previous studies have found that generation costs went down in deregulated markets, but it is still unclear if this translated into lower prices for consumers (Fabrizio et al., 2007; Davis and Wolfram, 2012; Borenstein and Bushnell, 2015; Bushnell et al., 2017; Cicala, 2017). Contrary to the objectives of deregulation, we show that prices increased in deregulated markets, despite modest reduction in costs. Thus, the increase in markups dominated the efficiency gains, indicating the widespread presence of market power. Our findings show that deregulation does not always lead to lower prices to consumers.

For our empirical analysis, we exploit a unique dataset that covers the annual electricity flows through each electric utility territory from 1994 through 2016. Using this data, we compare utilities that were subject to state-specific deregulation policies to similar utilities in other states that remained tightly regulated using a difference-in-differences matching approach. By matching utilities based on their size and fuel mix, we are able to control for initial differences in cost and exposure to different cost shocks in the future. We then compare how prices, costs, and markups have evolved for these two groups of utilities. We obtain two main findings. First, we find substantial price *increases* for consumers in deregulated states, relative to consumers in regulated states. Costs, on the other hand, decreased in deregulated states, which indicates that the price increase was driven by higher markups. Overall, we estimate that net markups—retail prices minus generation costs—increased by 14 dollars per MWh from 2000 to 2016. Relative to 1999 price levels, this change in markups corresponds to an 18 percent increase in prices over the period. We decompose this effect into increases in wholesale markups of 9 dollars per MWh and retail markups of roughly 6 dollars per MWh. One of the key components of the deregulation process in electricity markets was the vertical separation of utilities between generation and retail. Our results suggest that market power among generators and the additional effect of double marginalization outweighed the modest gains in cost efficiency.

Evidence of strong market power in electricity markets does not come as a surprise, and has been documented by the previous literature (e.g., Borenstein et al., 2002; Bushnell et al., 2008; Ito and Reguant, 2016; Puller, 2007). Several characteristics of electricity make these markets particularly prone to market power. Both demand and supply are very inelastic, yet supply must meet demand at every moment since large amounts of electricity cannot be stored efficiently. Transportation is expensive, which makes markets very local and significantly limits the number of generators that can serve each utility. As a result of these factors, only a few generators are typically competing to cover demand for a certain area in a particular moment, and at times the relative scarcity gives them substantial market power. Deregulation did not generally result in increased competition within a local area, as each utility often transferred ownership of its entire generation portfolio to a single new entity. These forces, in addition to the inherent complexity of power systems, make competitive outcomes hard to achieve after the transition to market-based prices.

Our second finding is to show that the market restructuring intended by deregulation was delayed for several years. Despite the divestiture of generation assets, utilities maintained a high degree of vertical integration through contracts and common ownership. Thus, we distinguish between *apparent deregulation*—the share of a market supplied by companies other than the incumbent utility—and *effective deregulation*—the share of a market supplied by companies unaffiliated with the incumbent.¹ In wholesale markets, we find that the use of contracts with affiliated companies delayed the onset of effective deregulation by many years, compared to apparent deregulation. In retail markets, caps on retail rates and other factors slowed down the introduction of competitive supply. Consistent with these delays, we observe a much larger effect of deregulation on prices once restructuring measures are actually brought into effect.

Though we find that deregulation did not result in lower prices to consumers, our results do not necessarily imply that the deregulation of the sector has failed. First, markets may be better at investment, either by reducing costs or by responding better to the needs of decarbonization.

¹We use the term "affiliate" as a company belonging to the same parent company.

Though we do not observe these effects in prices nearly 20 years later, such gains may be realized in the longer run. Second, improved organization and design of electricity markets may be used to avoid excessive market power, potentially allowing the efficiency gains to be at least partially passed on to consumers. While we still do not have an answer for these questions, it is certainly possible that markets can bring benefits to consumers.

Our findings can be summarized in terms of two main contributions. The first contribution is to demonstrate the importance of the tradeoff between market power and cost efficiency in the analysis of the consequences of deregulation. The electricity sector allows us a rare opportunity to document the parallel evolution of costs, prices, and markups in deregulated and regulated markets. Although it is well known in the literature that electricity markets are prone to market power (e.g., Borenstein et al., 2002; Hortacsu and Puller, 2008; Ito and Reguant, 2016), the fact that it could by far outweigh the savings from increased cost efficiency is unexpected.

We explore several possible mechanisms for increased prices in deregulated states, and we argue that our findings are most consistent with the exercise of market power by generation firms. Regardless of the mechanism, our high-level finding that *deregulation did not decrease prices* merits attention. The existing literature on the consequences of deregulation is surprisingly scarce, given the importance of the electric sector for the economy and decarbonization efforts. We know that deregulation has brought some gains in productive efficiency (Fabrizio et al., 2007; Davis and Wolfram, 2012; Cicala, 2017), but there is little evidence of the effect on prices (Bushnell et al., 2017). We are the first to show that deregulation has resulted in increased prices from market power, and that this effect has dominated cost efficiencies.

The second contribution is to present the first thorough description of how U.S. electricity markets changed after deregulation, including both the upstream and the downstream markets. We are able to do this by exploiting two rich datasets that have not been combined before at this level of detail. These are: FERC Form 1, which contains detailed information on (formerly) regulated utilities, including costs and procurement sources, and EIA-861, which contains utility-level aggregate data on generation, purchases, and sales. By combining these data, we introduce a new dimension to the analysis of electricity markets restructuring: vertical integration. We show that accounting for intermediate degrees of vertical integration is key to understand how markets responded, since they used them to effectively delay the loss of market control by the incumbent utility.

Bushnell et al. (2008) and Mansur (2007) discuss the role of vertical integration in deregulated markets and show that spot wholesale electricity markets are more competitive when generators are vertically integrated because they have fewer incentives to increase prices. Our paper complements these finding by looking at the market as a whole instead of focusing on the spot market, which constitutes roughly 15 percent of the entire wholesale market in deregulated states. We also account for intermediate degrees of vertical integration in the analysis.

The paper proceeds as follows: Section 2 provides a background of deregulation efforts and

a conceptual framework for our analysis. Section 3 describes our dataset and key summary statistics. Section 4 details our empirical strategy and provides our main results for prices, costs, and markups. We discuss the timing of the observed effects, and we provide a detailed case study on deregulation in Illinois to illustrate how effective deregulation may be delayed. Section 5 presents supporting evidence for the role of market power in deregulated markets. Section 6 provides a discussion of potential alternative explanations. Section 7 concludes.

2 Background and Conceptual Framework

2.1 Deregulation Process

In the 1970s and 1980s, there was a wave of deregulation to encourage entry and allow marketbased prices in many industries that had been considered natural monopolies, such as telecom, airlines, and surface freight. Although the details of the deregulation process varied across industries, the principles governing this process were the same: reduced entry barriers and market competition will increase efficiency and reduce prices. There was a consensus that some industries had undergone significant changes in their cost structures, allowing for beneficial effects of competition. Telecom was an extreme example in which major changes in demand and technology had moved the sector away from a natural monopoly, making it an obvious candidate for deregulation.

Many of these deregulation efforts have been considered successful because prices have fallen, though in some cases at the cost of reduced quality (Borenstein and Rose, 2014; Viscusi et al., 2018; Joskow, 2005). However, even in successful cases, these industries remain highly concentrated, often appear in controversial merger cases, and engage in behavior that raise concerns about market power (Borenstein, 1989; Borenstein and Rose, 1994, 2014; Viscusi et al., 2018). For example, after the deregulation of airlines and the significant fall in prices that followed, we saw concentrated, even after significant growth in demand and technological improvement (Viscusi et al., 2018). High levels of concentration suggest that market power may be an important concern in deregulated industries, where characteristics like high fixed costs or network economies that once led regulation to be considered necessary may be the same that make them prone to market power.

The next section briefly describes how the deregulation process of the electricity sector took place. Though each industry has different institutional details, the basic tradeoff between efficiency and market power that we describe in the electricity sector will also be relevant in other deregulated industries.

2.2 Restructuring of the U.S. Electricity Markets

Traditionally, electric utilities in the U.S. and the world were vertically integrated companies that included generation, transmission from power plants to towns and cities, distribution along power lines to final consumers, and retail sales to these consumers. Because electricity was considered a natural monopoly, a single utility served each local market, and electricity prices were regulated to avoid monopoly pricing. Utilities were reimbursed based on their average costs of generation. Following a wave of what was considered successful deregulation in other sectors, like telecommunications and airlines, the electricity sector started its own process of deregulation in the 1990s.

Though competitive generation was allowed in the whole United States since 1978 (Public Utility Regulatory Policies Act, known as PURPA), entry was limited due to the lack of incentives for utilities to purchase from new entrants and to share transmission assets with competing generation facilities. In the late 1990s and early 2000s, several states passed policies aimed at introducing competition into both upstream generation and downstream retail markets. The transmission and distribution grids were still considered natural monopolies; therefore, through federal regulation, the transmission grid was put into hands of an Independent System Operator (ISO), whose role was to coordinate the usage of the grid and ensure access to competitive generation. Utilities maintained the distribution lines, regardless of whether their state implemented deregulation measures. In deregulated states, competitive retailers were able to make use of the distribution grid and sell directly to end consumers. These consumers paid a regulated distribution rate to the utility, in addition to paying for the electricity from the retailers.

The specific timing and rules governing the process of deregulation varied across states. Most states required utilities to divest at least part of their generation assets to encourage the creation of a competitive generation sector. As we show in the paper, states varied in how strict the separation between utilities and generation was required to be, and in many cases utilities just split themselves into a generation and a distribution branch. The second major component of the process was the introduction of competition at the retail level. Partly because of uncertainty and skepticism about whether it would be effective and whether consumers would be protected from high prices, there were also wide differences in how states implemented retail competition. Twenty years later, a high share of industrial and commercial customers have switched to competitive retailers, but, in most states, the large majority of residential consumers still purchased from the incumbent utility.² Typically, incumbent utilities were still required to offer "bundled service," in which they provided electricity at regulated rates in addition to the delivery services that they also provided for competitive retailers.

Deregulation was expected to bring increased efficiency by providing incentives to reduce costs, and evidence indicates that in fact power plants are both operated more efficiently (Fabrizio et al., 2007; Cicala, 2015) and dispatched more efficiently (Cicala, 2017). Although previ-

²See Hortaçsu et al. (2017) for a discussion of the reasons behind this.

ous research has found evidence of significant market power in deregulated electricity markets (Borenstein et al., 2002; Puller, 2007; Mansur, 2007; Ito and Reguant, 2016), the literature so far has paid less attention to the role that market power may have in translating this efficiency gains into lower prices for consumers. This paper aims at filling this gap.

In the next section, we present a simple model to illustrate how these two forces act on prices for the case of electricity restructuring. On the one hand, competition among generators to sell in the wholesale market should bring stronger incentives to reduce costs, increasing productive efficiency. On the other hand, vertical separation may lead to higher prices through double marginalization, since wholesale sellers will now markup their prices. The final effect will depend on the relative magnitude of these two effects.

2.3 Conceptual Framework

Consider a single regulated utility that initially generates electricity at marginal cost c_1 and sells it to final customers at a price

$$P_1 = c_1 \cdot m_1,\tag{1}$$

where m_1 is the markup that the regulator allows the firm to earn under rate of return regulation.

After restructuring, the utility is vertically separated and a wholesale market is created, such that the utility no longer generates its own electricity and now has to purchase it in the wholesale market at a price $w(c_2)$. This price will be a function of the marginal cost of production c_2 , which may be different from c_1 because plants' operation, dispatch, and investment may change after restructuring. For simplicity, we assume that the regulator does not change the markup the utility is allowed to charge so the retail price is now

$$P_2 = w(c_2) \cdot m_1. \tag{2}$$

By holding the retail markup fixed, we see from these two equations that the change in prices after deregulation depends on how the wholesale price w compares to the marginal cost under regulation c_1 :

$$P_2 < P_1 \iff w(c_2) < c_1. \tag{3}$$

We can decompose this relationship into two components. The first are potential efficiency gains, which translate into lower costs under restructuring: $c_2 < c_1$. The second component is the relationship between w and c_2 , which depends on market power in the wholesale market. If the wholesale market is perfectly competitive, $w = c_2$. In this case, any efficiency gains resulting in $c_2 < c_1$ will be passed on to prices and we will have $P_2 < P_1$. This was indeed the goal at the time of restructuring.

If the wholesale market is not perfectly competitive, generators will charge a markup and

the wholesale price will be

$$w = \frac{c_2}{1 + \frac{1}{\epsilon}},\tag{4}$$

where ε is the elasticity of the demand faced by the wholesaler. The generator will charge a positive markup as long as they face a demand that is less than perfectly elastic.

In addition, competitive retailers are able to charge a markup m_2 that is greater than the regulated markup, m_1 . Thus, the presence of double marginalization—through larger retail markups $(m_2 - m_1)$ on top of wholesale markups $(w - c_2)$ —could outweigh the the efficiency gains that have been documented in the literature (Fabrizio et al., 2007; Cicala, 2015, 2017; Jha, 2020).

2.4 Market Power in Electricity Markets

Despite electricity being a homogeneous product, suppliers can have substantial market power. Transportation over long distances is expensive, which limits the effective size of geographic markets. Further, large amounts of electricity cannot be stored efficiently. Thus, supply and demand for a particular location at a particular point in time can be quite inelastic, providing individual suppliers with opportunities to exercise market power.

Previous work in the literature has shown significant degrees of market power among generators (Puller, 2007; Hortaçsu et al., 2017; Borenstein et al., 2002). During the crisis in California at the beginning of its deregulation process, for example, all generators had market shares below 10 percent and still were able to charge markups of around 100 percent (Borenstein et al., 2002; Borenstein, 2002). While it is true that during that particular period conditions were very favorable to market power, we also know that most electricity markets have a more concentrated supply than the market in California (Ito and Reguant, 2016; Hortacsu and Puller, 2008). This suggests that substantial efficiency gains would be required in order to compensate for the higher markups and reduce prices after restructuring.

Indeed, the example of California is illustrative because it happened at the beginning of the restructuring process, when utilities still retained significant market power. Over time, changes in concentration in the generation market and the downstream retail market would also affect the use of market power. Increasing concentration in generation and decreasing concentration in retail could both reduce the utilities' bargaining power and increase wholesale markups.³

While nationwide deregulation measures facilitated the exchange of electricity across geographic markets, local deregulation did not do much to increase within-market competition. Utilities tended to sell of their entire portfolio of generation to a single new entity. Thus, generating facilities in deregulated markets did not see an increase in local competition.

Figure 1 provides an illustration of how market power could increase prices in deregulated

³Section 5 documents how concentration among sellers has increased in deregulated markets while concentration among buyers has fallen.





Notes: Figure illustrates how market power could increase prices in deregulated markets, despite the presence of cost efficiencies. The thick black line labeled MC plots the perceived marginal cost curve under a regulated regime. The regulated prices are set to reimburse average costs, which are plotted with the thin black curve (unlabeled). With efficient investment, average costs equal MC at the intersection with the demand curve, D, resulting in price P^R . Cost efficiencies from deregulation are illustrated with a downward shift in the marginal cost curve to the thick gray line MC'. In a competitive market, prices will equal $P^C < P^R$. With market power, firms could raise prices up to P^M , which is determined by the intersection of MC' and the marginal revenue curve, MR.

markets, despite the presence of cost efficiencies. The residual demand curve facing an electric supplier is plotted by the black line labeled D. The thick black line labeled MC plots the perceived marginal cost curve under a regulated regime. The regulated prices are set to reimburse average costs, which are plotted with the thin black curve. With efficient investment, average costs equal MC at the intersection with the demand curve, resulting in regulated price P^R .

In competitive markets, profit incentives could lead firms to more efficiently allocate the supply of electricity. These potential cost efficiencies are illustrated with a downward shift in the marginal cost curve. The new marginal costs are plotted with the thick gray line MC'. In a competitive market, prices will be determined by the intersection of the demand curve with the marginal cost cure, resulting in price $P^C < P^R$. With market power, firms could raise prices up to P^M . P^M is the monopoly price and is determined by the intersection of MC' and the marginal revenue curve, MR.

In this figure, deregulation could result in prices ranging from P^C to P^M , depending on the degree of market power. Overall, whether retail prices increase or decrease after restructuring is an empirical question, depending on the relative importance of efficiency gains and market power. In the following sections, we present evidence that modest efficiency gains were outweighed by sharp increases in wholesale markups, resulting in higher prices.

3 Data

3.1 Dataset Construction

Our main objective is to construct annual measures for generation, purchases, and retail sales within each utility's distribution territory. We obtain measures of quantities (MWh) and expenditures, allowing us to calculate average generation costs, average wholesale prices, and average retail prices. Our data accounts for the fact that, while the structure of the deregulated market changed, the geographical territories for distribution essentially remained unchanged, and the ultimate delivery of electricity to consumers continues to be the responsibility of the incumbent utilities.

We construct our unique dataset from several sources. Our main sources of data are reports provided by the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC) from 1994 through 2016. Those these reports are publicly available, though they have not previously been combined at this level of detail. Utility-level aggregate data on generation, purchases, and sales is obtained from the operational data in form EIA-861. Form EIA-861 also provides more detailed measures of retail sales, which we use to construct state-specific measures of bundled service and delivery service for each utility.

Detailed data on purchases is obtained from FERC Form 1. By augmenting the transactionlevel data with information on firm ownership structure, we construct an indicator of whether a purchase is made from an affiliated company. We use this measure to track what fraction of total sources obtained by a utility come from the same parent company versus independent suppliers.⁴ The data on ownership structure was manually built from a combination of sources, including current corporate structure from S&P Global, data on corporate structure, name changes, and mergers and acquisitions collected by the Edison Electric Institute,⁵ and manual Google search for confirmation.

Deregulation measures were implemented by 21 states in this period.⁶ Four states—Arizona, Arkansas, Nevada, and Montana—initially passed deregulation measures but later rescinded them. We remove them from our sample. We also remove Hawaii and Alaska, as the electricity infrastructure in these states is quite different from the rest of the United States. Finally, because Nebraska and Tennessee do not have investor-owned utilities with generation resources, they are not included in the sample. Thus, our sample of utilities covers 17 states that implemented deregulation measures and 25 states that did not. For additional details, see Appendix

A.

⁴We are also able to use this data to measure the share of sources coming directly from the markets run by the Independent System Operators (ISOs).

⁵See Edison Electric Institute, Profiles and Rankings of Investor-Owned Electric Companies, 2019.

⁶Our sample of states that deregulated includes Rhode Island, New York, California, New Hampshire, Massachusetts, Pennsylvania, New Jersey, Delaware, Maryland, Connecticut, Illinois, Maine, Ohio, Texas, Virginia, Oregon, and Michigan.

3.2 Unit of Analysis and Key Variables

The unit of analysis in our study is the service area covered by investor-owned utilities (IOUs) in each state. Electric service in the United States is provided by three types of entities: IOUs, nonprofit cooperatives, and public utilities. IOUs were the primary target of deregulation measures, as they could make profits, were disproportionately larger than other types of utilities, and provided the vast majority of electricity service. In 1994, the 250 IOUs provided 75 percent of generation and 76 percent of retail service in the United States.⁷ Since investor-owned utilities are subject to different regulations across states, we treat each utility with service areas in different states as separate utility-state entities. For some parts of our analysis, we will consider the state-wide electricity "market," as all utilities in that state are under the jurisdiction of the same state-specific regulatory commission.

Though deregulation measures ended generation and retail service for several utilities in our sample, these utilities continued to own and operate distribution lines. Thus, we define our unit of analysis as each utility's service area. Service areas (i.e., the distribution infrastructure) are quite stable over time. For a visual representation of the geographic coverage of these areas, see Figure 14 in the Appendix. We also account for mergers of utilities throughout our sample period; if utilities merge at any point, we treat them as a single merged entity throughout our sample. For our analysis, we focus on utilities that had generation resources in 1994, at the beginning of our sample.

The key outcomes of interest are retail prices, wholesale prices, and costs. For our primary measure of retail price, we use the "default" price available to residential, industrial, and commercial customers of a utility. We construct this measure by taking the price for bundled service for each customer type and weighting these measures by the share of consumption by each customer type in the service area. Thus, we adjust for the fact that the composition of customers electing retail service from competitive sources changes over time. For Texas and Maine, several utilities no longer provide bundled service; for these utilities we instead use the average bundled price offered by power marketers in the state.

For wholesale prices, we use the average price for purchased electricity by each utility, which we obtain from the detailed transaction data in FERC Form 1. This measure has the advantage of reflecting demand and supply conditions that are local to each utility's service area. We also use this transaction data to capture the share of purchases that come from affiliated companies.⁸

For generation costs, we use generator-specific fuel receipts data from EIA to construct average fuel costs. We assign each generator to the utility that owned the generator in 1994

⁷In 1994, 3,207 utilities reported to the EIA. The remaining 2,957 utilities that were not IOUs consisted of 2,194 municipal utilities and cooperatives, which tended to be much smaller, and 156 publicly run power authorities at the federal, state, or subdivision level

⁸Our measure is somewhat conservative in that a utility may sell generation to a power marketer who then supplies electricity to a delivery customer of the utility. We cannot track this in the data, but if we could it would strictly increase our measure of affiliated purchases.

	(1)	(2)	(3)	(4)	(5)
	Deregulated	Control		Matched Controls	
	Mean	Mean	p-value of Difference from (1)	Mean	p-value of Difference from (1)
ln(MWh Retail)	15.23	15.27	0.939	15.42	0.708
ln(MWh Generated)	14.66	14.71	0.933	14.66	0.999
Generation Share: Coal	0.40	0.53	0.186	0.47	0.499
Generation Share: Gas	0.20	0.12	0.383	0.13	0.431
Generation Share: Nuclear	0.13	0.08	0.203	0.12	0.865
Generation Share: Oil	0.12	0.03	0.081	0.06	0.314
Generation Share: Water	0.14	0.23	0.456	0.22	0.508
Fuel Costs	50.57	22.34	0.087	29.37	0.267
Retail Price	78.77	58.84	0.001	59.08	0.001
Net Markups	28.20	36.51	0.580	29.70	0.933
Number of Unique Utilities	78	75		73	

Table 1: Characteristics of Deregulated, Control, and Matched Control Utilities in 1994

Notes: Table displays 1994 characteristics for 78 investor-owned utilities in states that later deregulated and 75 investor-owned utilities in states that did not deregulate. Columns (1) and (2) report the mean characteristics for each group, and column (3) reports the p-value of the difference in means. Column (4) reports the means for matched controls using a nearest-neighbor methodology, and column (5) reports the p-value of the difference in means between matched controls and the deregulated utilities. The first seven variables: (log) retail MWh, (log) generation MWh, and generation share by fuel type are used as matching variables.

for the entire sample. Thus, despite changes in ownership as a result of deregulation, we preserve a proxy for generation costs that are specific to each utility's service area. To account for investment in new generation resources, we employ a second measure of costs, which is the average statewide fuel costs across all generation facilities in the state.

3.3 Summary Statistics

In this section, we provide some summary statistics of key variables in our sample. We identify similarities and differences between the treated and control utilities in our sample. Some of the differences motivate our nearest-neighbor matching approach, which we describe in Section 4.

Table 1 shows the key variables for treated and control utilities in 1994. Column (1) reports the mean across the 78 IOUs in the deregulated states, and column (2) reports the mean across the 75 IOUs in the control states. Overall, utilities in deregulated and control states were similar in size in 1994, in terms of retail and generation. There are some differences in generation mix across the two groups. Deregulated states had lower shares of coal and water and higher shares of natural gas, nuclear, and oil. This gives rise to a difference in fuel costs, which are roughly twice as large in deregulated states in 1994. Despite this, the p-values of the difference in means for these variables, which are reported in column (3), are greater than



Figure 2: Aggregate Measures of Electricity Prices and Generation Costs

Notes: Panel (a) plots the quantity-weighted default retail price for investor-owned utilities in deregulated states (solid blue line) and in control states (dotted red line). Panel (b) plots the average fuel costs of generation for all generating facilities that in 1994 belonged to utilities in deregulated states (solid blue line) and control states (dotted red line). The red dashed line in both panels plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

0.05, indicating no statistically significant differences. This finding, despite the economically meaningful differences in mean fuel costs, reflects the presence of a great deal of heterogeneity among utilities within each group.

Both of these features: mean differences across groups and heterogeneity within groups motivate our use of a matching procedure. By matching each deregulated utility to a set of similar controls, we can account for some of the heterogeneity in utility type. Specifically, we match utilities to three nearest neighbors based on (log) retail MWh, (log) generation MWh, and the share of generation from different fuel sources. Thus, we obtain a utility-specific control group that reflects both the type of generation and the size of the utility. We draw nearest neighbors from the pool of 75 control utilities. We provide additional details of our matching procedure in Section 4.2.

Column (4) in Table 1 reports the means for the nearest-neighbor controls, which are weighted by the number of times each utility is selected. Overall, the group becomes more similar to the deregulated utilities in terms of generation mix and fuel costs. For example, the difference in nuclear share shrinks from 0.05 to 0.01. Correspondingly, the p-values for the matching variables tend to increase. The average p-value for the matching variables increases from 0.454 in column (3) to 0.618 in column (5). Note that the matching procedure only selects 73 out of the 75 possible control utilities as nearest neighbors.

After accounting for size and generation mix, we find that utilities in deregulated states had higher prices than similar utilities in control states (78.77 versus 59.08 in 1994). Though retail prices were higher, the net markups—in terms of the difference between retail prices

and fuel costs—is quite similar (28.20 versus 29.70). Thus, fuel costs can explain nearly all of the differences in prices across the two groups, suggesting that there may be no systematic differences in unobservables that affect markups. In addition, the difference in prices between the two groups was stable before the onset of deregulation. In Figure 2, we present the time series of average prices for both groups. Panel (a) shows the mean retail price for deregulated states with a blue line and the mean for control states, after adjusting for level differences in 1999, with a red dashed line. From 1994 to 1997, prices were stable in both groups. From 1998 to 2000, prices in deregulated states fell slightly, while prices in control states remained flat. Starting in 2001, prices in both states began to rise. Deregulated prices outpaced control prices until 2005, when the gap between the two widened further.

Likewise, panel (b) of Figure 2 shows average fuel costs for the two groups. For this figure, we construct the average fuel costs as the average fuel cost for the generators that utilities in each group owned in 1994.⁹ After accounting for level differences, fuel costs for generation facilities in deregulated markets closely tracked fuel costs in control markets from 1994 through 2004. Starting in 2005, generation costs began to decline, and they declined more rapidly in deregulated markets. This pattern can largely be explained by the greater use of natural gas generators in deregulated states, as the price of natural gas fell significantly with the expansion of fracking.

Thus, though retail prices rose substantially in deregulated states, there was no corresponding rise in fuel costs in these states. Using our localized measure of generation costs, we find that fuel costs in deregulated markets declined overall. This high-level finding is consistent with an increase in markups in deregulated states relative to control states, and motivates our more in-depth empirical analysis in Section 4.

4 Measuring the Effects of Deregulation

4.1 Empirical Strategy

The goal of our analysis is to evaluate the effect of electricity restructuring on prices and, in particular, to determine whether increased market power was offset by higher cost efficiency. For this, we compare utilities in restructured states to those that remained vertically integrated and regulated, and we look at the evolution of costs, wholesale prices, and retail prices over time. Specifically, we use a difference-in-differences matching approach, which we describe in greater detail in the next section.

By individually matching utilities based on their size and generation mix prior to the onset of deregulation, we are able to nonparametrically control for changes to macroeconomic factors—such as fuel costs and demand for electricity—when measuring a number of outcome variables.

⁹The same figure using our alternative measure in which we use all generators in the state is presented in the Appendix in Figure 17.

Intuitively, we are using the data to provide an answer to the question, "What happened for similar utilities in states that did not deregulate?"

Because a state decision to restructure its electricity sector was not completely random, causal inference in this context is difficult.¹⁰ A causal interpretation of our findings would require the assumption of parallel trends, which has several nuances in our context. First, it requires that there were no ongoing trends that differentiated the two groups outside of deregulation. Though comparable utilities in states that implemented deregulation measures initially had higher retail prices (Table 1), markups were similar, and costs and prices follow similar trends from 1994 through 1999 (Figure 2). This suggests that the parallel trends assumption may be reasonable before the onset of restructuring.

Second, the parallel trends assumption requires that shocks unrelated to deregulation did not differentially affect deregulated and control states after implementation. The primary concern on this front arises from changes in fuel costs, which we control for using our matching approach.

Third, the assumption requires that the effects of deregulation did not spill over into control states. We believe this assumption to be the most problematic. Because of the ongoing integration of electricity markets across states, it is plausible that deregulation may have affected retail prices in neighboring states. If we account for spillovers, the data suggest that our findings may be a conservative *lower bound* of the effects of deregulation, as we also observe large increases in retail prices and markups in control states (Figure 2).

A final consideration is whether other aspects of markets that affected market power and cost efficiency developed differently following deregulation. For example, we expect entry decisions to follow different dynamics in restructured and vertically integrated states. We do not want to control for all of these factors, as some endogenous responses are part of the effect we want to estimate. Keeping this distinction in mind, we examine alternative mechanisms that could potentially affect our findings in Section 6. Though we find some differences in policies affecting deregulated and control states, these differences do not provide a consistent alternative explanation for the changes in prices and markups we observe. Thus, despite the above caveats, we believe our empirical results provide a compelling narrative that suggest the widespread presence and practice of market power.

4.2 Difference-in-Differences Matching Estimator

To measure changes in outcomes for deregulated utilities, we match utilities in states that implemented market-based prices (the "deregulated" group) to utilities in states that did not (the "control" group) based on pre-deregulation retail MWh, generation MWh, and fuel type.

¹⁰This is highlighted by how little we know about the consequences of restructuring 20 years later (Bushnell et al., 2017), in spite of the sector's importance and the urgency of good market rules to deal with the challenges brought by decarbonization.

We then apply a difference-in-differences adjustment to the bias-corrected matching estimator developed by Abadie and Imbens (2006, 2011). Our estimation procedure closely follows the approach of Deryugina et al. (2019). Though we use the term "control" and "counterfactual," it is important to note that the state-specific decision to deregulate was not purely random, as discussed in the previous section.

For each of our 78 deregulated utilities, we use 1994 outcomes to identify the three nearest neighbors from the pool of 75 control utilities in our sample. We use 8 match variables, consisting of log generation MWh, log retail MWh, and the shares of generated MWh coming from six fuel types: coal, natural gas, oil, nuclear, water, and other renewables. We use a least-squares metric to calculate the calculate distances between utilities. As it is important to control for changes in fuel costs, we scale the fuel type shares by a factor of 25 to prioritize matching based on the fuel mix.¹¹ We use this distance to select the three nearest neighbors for each deregulated utility, allowing control utilities to be matched to multiple deregulated utilities.

We use these nearest neighbors to construct counterfactual outcomes and employ standard difference-in-differences techniques to adjust for pre-period differences. Let Y_{it} denote an outcome of interest (e.g., retail prices) for utility *i* in period *t*, where t = 0 corresponds to the year deregulation measures are implemented. Let $Y_{it}(1)$ indicate the outcome with deregulation and $\widehat{Y}_{it}(0)$ indicate estimated counterfactual without deregulation. Given $Y_{it}(1)$ and $\widehat{Y}_{it}(0)$, we can obtain a utility-specific estimate of the effect of deregulation on the outcome, $\widehat{\Delta Y}_{it}$:

$$\widehat{\Delta Y}_{it} = Y_{it}(1) - \widehat{Y}_{it}(0).$$
(5)

We observe the outcome $Y_{it}(1)$ for the deregulated utilities in our data. The counterfactual outcome, $\hat{Y}_{it}(0)$, is unobserved and is calculated as follows. For each deregulated utility *i*, we select M = 3 nearest neighbors using the above procedure. We calculate the counterfactual outcome, $\hat{Y}_{it}(0)$, as the average value of $Y_{it}(0)$ across the control utilities plus the difference between deregulated and matched control outcomes in the period prior to deregulation. Thus, outcomes are indexed so that $Y_{i0}(1) = \hat{Y}_{i0}(0)$. By indexing the levels to a baseline period, we obtain a utility-specific "difference-in-differences" estimate for any outcome of interest.

To quantify the average impact of deregulation across our utilities, we take the weighted average of the utility-specific treatment effects:

$$\widehat{\overline{\tau}}_t = \frac{\sum_i \omega_i \widehat{\tau}_{it}}{\sum_i \omega_i}.$$
(6)

where ω_i is the retail MWh provided by the deregulated utility in 1994. Our weighting variable is chosen to capture the size of the utility with respect to consumption in its service area.

For our main analysis, we use 1999 as our baseline period across all states. Though there is

¹¹This factor is somewhat ad hoc, but it produces good matches on average. Our results are similar under alternative scaling approaches.

some variation in terms of when deregulation measures legally came into effect across states, in practice, the restructuring effects all happened within a few years. This timing has little impact on the results we measure, which occur over 15 years after deregulation. Using a common baseline period has the advantage of making the empirical results more transparent, especially for concerns about macroeconomic trends, such as changes in fuel prices. Our results are similar if we instead index treatment communities to their legal deregulation date.¹²

As in Deryugina et al. (2019), we employ a subsampling procedure to construct confidence intervals for our matching estimates.¹³ Consider a parameter of interest, $\hat{\theta}$. For each of $N_b =$ 500 subsamples, we select without replacement $B_1 = R \cdot \sqrt{N_1}$ deregulated utilities and $B_0 =$ $R \cdot \frac{N_0}{\sqrt{N_1}}$ control utilities, where R is a tuning parameter, N_1 is the number of deregulated utilities, and N_0 is the number of control utilities. For each subsample, we calculate $\hat{\theta}_b$. The matching estimator converges at rate $\sqrt{N_1}$ (Abadie and Imbens, 2006, 2011), and the estimated CDF of $\hat{\theta}$ is given by:

$$\widehat{F}(x) = \frac{1}{N_b} \sum_{b=1}^{N_b} \mathbf{1} \left\{ \frac{\sqrt{B_1}}{\sqrt{N_1}} \left(\widehat{\theta}_b - \widehat{\theta} \right) + \widehat{\theta} < x \right\}$$
(7)

The lower and upper bounds of the confidence intervals can then be estimated as $\hat{F}^{-1}(0.025)$ and $\hat{F}^{-1}(0.975)$. We employ R = 3 ($B_1 = 26$) for the confidence intervals and standard errors reported in the paper.

4.3 Prices, Costs, and Markups

We first show that retail electricity prices increased for customers in deregulated states. Panel (a) of Figure 3 displays the average change in retail prices relative to matched controls. Leading up to the baseline year of 1999, there is little difference in price trends for deregulated and control utilities. From 2000 to 2005, deregulated utilities saw modest increases in retail prices, which an average difference of 3.0 dollars per MWh over that period. In 2006, deregulated utilities realized a sharp rise in retail prices, with an average difference of 12.0 dollars per MWh from 2006 to 2011 and 8.7 dollars per MWh from 2012 to 2016. The increases in the latter years are large in magnitude. The average retail price for deregulated utilities in 1999 was 78.0 dollars per MWh, so an increase of 12.0 dollars per MWh corresponds to a 15 percent increase in prices relative to the baseline. We reiterate that these changes are difference-in-differences effects, i.e., increases above and beyond the price trends occurring in control utilities.

A natural question is whether the price changes reflect underlying changes in costs. Panel (b) of Figure 3 plots the relative change in average variable costs, in terms of fuel costs, for deregulated utilities. Relative to control utilities, deregulated utilities saw a *decrease* in genera-

¹²For a comparison, see Section B.2 in the Appendix.

¹³Matching estimators do not meet the regularity conditions required for bootstrapping (Abadie and Imbens, 2008), and subsampling provides great flexibility in terms of calculating treatment effects.



Figure 3: Estimates of Changes in Prices and Costs After Deregulation

Notes: Figure displays difference-in-differences matching estimates of changes in (a) retail prices and (b) fuel costs for deregulated utilities. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to 1999, which is the year prior to the first substantial deregulation measures. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

tion costs in the post-deregulation period. From 2000 to 2016, fuel costs declined by 5.8 dollars per MWh in the deregulated utilities. Thus, despite declining costs, prices rose in deregulated states.

The combined effects of increasing prices and decreasing costs suggest that markups to consumers rose in deregulated states. To illustrate this, we combine the retail price effects and the generation costs on the same plot in panel (a) of Figure 4. The difference between the retail price (in blue) and the fuel costs (in red) is the net markups paid by end consumers above the generation costs of electricity. The net markups are plotted in panel (b). The increase in net markups was modest from 2000 until 2005. Markups spiked in 2006, reaching over 23 dollars per MWh in 2008 and 2009.

Our finding of increasing markups is robust to our preferred measure of costs. As an alternative measure to the utility-specific generation costs, we use the average statewide fuel costs. An argument for using this measure as opposed to the utility-specific measure is that, in a competitive market, consumers may obtain electricity from a lower-cost source that is nearby but outside of their service area. The gray dashed line in panel (a) plots the change in statewide fuel costs. Though the decline is not as large as the utility-specific measure, we find that statewide fuel costs decline in deregulated utilities relative to their controls. The gray dashed line in panel (b) plots the net markup for retail prices using this alternative measure of costs. We still find large increases in net markups to consumers using this alternative measure.

The finding that consumers pay higher net markups in deregulated utilities is consistent with



Figure 4: Prices, Costs, and Net Markups

Notes: Figure displays difference-in-differences matching estimates of changes in prices, costs, and net markups for deregulated utilities. Panel (a) provides the point estimates for retail prices (thick blue line) and utility-specific fuel costs (red line) from Figure 2 on the same plot. The dashed line on the plot represents an alternative measure of costs reflecting the average statewide fuel costs for all generators in each utility's state. Panel (b) displays the changes in the net markups, which are defined as the retail price minus fuel costs, using both measures of costs from panel (a).

the exercise of market power. Regulated retail prices are set to reimburse the average cost of generation, in addition to providing a reasonable return on invested capital. In effect, regulated utilities earn approximately zero profits on generation. In deregulated states, generators earn profits by charging a markup above generation costs when selling to retail firms. The net markup we observe captures both the markup charged by generators in the upstream wholesale market, and the additional markup charged by retailers to downstream customers.

To illustrate market power in the upstream market, we examine prices and costs for utilities that continue to provide bundled service in the retail market. Panel (a) of Figure 5 shows the procurement cost for utilities. A utility's average variable cost (thick green line) is the weighted average of the average fuel cost for generation by the utility (red line) and the average cost of electricity purchased on the wholesale market (dashed purple line). Deregulated utilities saw an increase in average variable costs beginning in 2000 and increasing over the sample period.

Two factors contribute to the increase in average variable costs. The first is that, by separating from generation facilities, deregulated utilities had to procure a greater portion of the electricity sources from the wholesale market. For a utility, obtaining electricity from the wholesale market was more expensive than generation, as wholesale prices reflect a markup. In 1999, the mean wholesale markup was 18 dollars per MWh. With deregulation, utilities effectively paid a market-based markup to generation facilities that they had previously owned. Thus, despite the fact that wholesale prices and fuel costs both *declined* over the period 2000 to 2005,





(a) Utility Variable Costs

(b) Utility Prices, Costs, and Markups

Notes: Figure displays difference-in-differences matching estimates of changes in costs, prices, and markups for regulated electric service in deregulated states. The green line in both panels shows the change in average variable costs for utilities. Each utility's average variable cost is calculated as the weighted average of generation fuel costs and wholesale purchase prices. Changes in these variables are shown in panel (a). Variable costs increase from 2000 through 2005 despite no increase in generation fuel costs (red line) and wholesale purchase prices (dashed purple line) because utilities procured a greater fraction of electricity from wholesale markets. Panel (b) plots the regulated bundled price (blue line) and the utility markup (dashed gray line), defined as the bundled price minus the average variable cost.

utility variable costs increased by 5.21 dollars per MWh.

The second factor that led to an increase in average variable costs for utilities was the increase in wholesale prices beginning in 2007. Though wholesale prices remained relatively flat in the initial years of deregulation, wholesale prices eventually increased substantially, rising by 7.5 dollars per MWh from 2012 to 2016. The increase in wholesale prices, combined with the significant declines in fuel costs, indicate that wholesale markups increased substantially in deregulated states. Our difference-in-differences estimate for the increase in wholesale markups is 14.1 dollars per MWh from 2012 to 2016, which is equivalent to a 78 percent increase in wholesale markups from the 1999 levels.

Though deregulation allowed for market-based prices upstream and downstream, deregulated utilities that continued to supply "bundled" service—i.e., providing retail service in addition to distribution—remained obligated to set regulated prices based on the procurement costs of electricity. These regulated prices rose substantially after deregulation, as shown by the blue line in panel (b) of Figure 5. The figure shows that the increase in utilities' average variable costs, represented by the thick green line, can explain nearly all of the increase in bundled prices offered by the utilities. In other words, consistent with regulated rates being set to reimburse variable costs, there are not significant changes in the markups charged by the utility, as measured by bundled prices minus average variable costs. The markups are plotted

	(1)	(2)	(3)	(4)	(5)
	Retail Price	Wholesale Price	Generation Cost	Retail Markup	Wholesale Markup
1999 Values	77.98	42.91	25.78	34.77	18.04
2000-2005	3.00	-1.19	-1.62	4.47	0.59
2006-2011	12.05	4.68	-8.90	7.69	13.59
2012-2016	8.71	7.52	-7.09	5.43	14.10
2000-2016	7.86	3.34	-5.78	5.71	8.98

Table 2: Relative Changes in Prices, Costs, and Markups

Notes: Table displays the estimated difference-in-differences matching cofficients for prices, costs, and markups between deregulated and control utilities in dollars per MWh. The first row provides the baseline values in 1999, and the remaining rows provide the average effect for the specified time period.

by the gray dashed line in the figure.

Table 2 summarizes the estimated difference-in-differences coefficients, as well as the baseline measures, for our key outcomes of interest.¹⁴ As discussed earlier, our findings are similar if we index each utility to state-specific implementation dates, rather than calendar time. Figure 15 in the Appendix shows that the share of own generation divested looks nearly identical using both measures of time. Figure 16 plots the corresponding effects on prices and costs, which are similar to the estimates in Figure 3 above.

4.4 Timing and Effective Deregulation

Price effects that result from deregulation may not be realized until many years after deregulation measures are enacted. Though many states were forced to legally separate from generation facilities abruptly, other measures were put in place that delayed actual changes to the structure of the market. For example, many utilities signed long-term procurement agreements with now independently operated generation facilities. These contracts effectively postponed the implementation of a competitive wholesale market, as much of the generation capacity was under long-term contracts. The possibility of delayed *effective deregulation* can explain why we observe larger price increases over time.

Here, we present the estimated delays arising across all deregulated utilities in our sample. To illustrate how upstream and downstream measures may have delayed deregulation in more detail, we examine a specific example in Section 4.5, where we present the experience of deregulation of Illinois as a case study.

Panel (a) of Figure 6 shows our measure of effective deregulation in the upstream market.

¹⁴The changes in markups in Table 2 do not always equal difference in changes between prices and costs because there are some periods where we do not observe wholesale prices for some utilities. In these cases, we do not calculate retail or wholesale markups.





Notes: Figure displays difference-in-differences matching estimates of changes in the incumbent utility's share of the upstream wholesale market and the downstream retail market. Panel (a) plots a utility's share of quantity demanded provide by its own generation (in blue) and by all affiliated sources (in red). The gap between the blue and the red lines indicates a delay between apparent deregulation and effective deregulation attributable to contracts and common ownership. Panel (b) shows the change in the incumbent utility's share in the downstream retail market.

The blue line shows the change in the share of consumption that was generated by incumbent utilities. The generation shares fell steeply from 1999 to 2002, with a drop of 44 percentage points. A few additional separations occurred in later years, with the total decline in generation shares reaching 54 percentage points by 2016. We do not observe a decline of 100 percentage points for two reasons. First, deregulated utilities were obtaining only roughly 80 percent of their consumed electricity in 1999 from generation, providing an upper bound for the effect of deregulation. Second, not all utilities in deregulated states were forced to separate generation from retail. For example, in Texas, only IOUs in the ERCOT region were affected. The other IOUs continued to operate as vertically integrated entities.

The red dashed line shows the affiliated generation share, which captures all generation occurring from utilities and generators owned by the same parent companies. This measure proxies for the long-term contracts signed my several utilities with their generators at the time of separation. The red line shows that the actual changes to the wholesale market lagged the apparent changes for many years. Though the naive share of competitive generation (i.e., one minus the point estimates in the graph) had increased by over 40 percentage points in 2002, this actual share of competitive generation did not cross this threshold until 2010, after accounting for common ownership across generators and utilities. By 2011, our measures converge, which is consistent with the expiration of the initial contracts and the completion of the transition to a competitive wholesale market.

This narrative lines up with the changes in costs we observe in Figure 5. From 2000 through

2004, while many of these contracts were in effect, there was little change in generation costs and wholesale costs. Coincident with the decline in affiliated generation shares starting in 2005, generation costs fell and wholesale markups increased. Taken together, these patterns are consistent with utilities signing long-term contracts at prevailing rates with their separated generation facilities, which delayed the onset of competitive markets for many years.

A second restriction that delayed the onset of competitive retail markets was the practice of implementing retail rate freezes in deregulated states. These rate freezes kept retail prices low, making the existing utility attractive to consumers and effectively discouraging new entrants. As shown in panel (b) of Figure 5, deregulated utilities saw a decrease in retail markups from 2000 to 2008. These rate freezes could have delayed the transition to competitive retail markets. As shown in panel (b) of Figure 6, competitive retailers obtained roughly 30 percent of the market by 2003. The transition plateaued at this level for several years. Beginning in 2007, the retail market saw a gradual increase in competitive providers, reaching 52 percent of the market by 2016.

An important regulatory change that might have had an effect on the observed timing for wholesale markups is the Energy Policy Act of 2005. In addition to several measures related to energy production and environmental regulation, the act lifted restrictions on the price at which utilities could buy electricity from independent generators. Until 2005, utilities were required to purchase electricity at a rate based on the utility's avoided cost, a measure of the amount that the utility would save by not generating its own energy. The Energy Policy Act repealed this requirement, allowing utilities to sign contracts at non-regulated rates in the presence of a competitive market. Lifting this restriction potentially allowed generators to charge higher prices and may have contributed to the increase in markups that we observe after 2005.

4.5 A Case Study of Delayed Effective Deregulation: Illinois

To help illustrate how the timing of deregulation was delayed by state-specific measures, we present Illinois as a case study. In the 1990s, Illinois' electricity rates were among the highest in the United States. Motivated by these high prices, Illinois lawmakers passed the Consumer Choice Act in 1997, which encouraged large investor-owned utilities to divest their generation assets and allowed for independent companies to supply electricity to commercial customers. For residential customers and small businesses, rates were lowered by 15 percent and frozen for 10 years. In 2002, retail choice was extended to residential and small commercial customers, thus allowing for competitive supply in the downstream market.

Within a few years, the investor-owned utilities in Illinois had sold off their complete portfolio of generation assets. This large change to the market is illustrated in panel (a) of Figure 7. The blue line represents the share of sources that investor-owned utilities obtained from their own generation. The remainder is obtained by purchasing electricity from other producers. The share of electricity sourced from own generation fell from above 80 percent at the time of the





Notes: Panel (a) of the figure displays the share of incumbent utilities' total sources provided by own generation for Illinois, which deregulated, and Missouri and Iowa, which did not. Panel (b) plots the share of incumbent utilities' total sources provided by affiliated sources, which include both own generation and purchases from companies belonging to the same parent company. The year 2006, which is the final year of several long-term contracts between affiliated companies, is indicated by a vertical dashed line.

restructuring initiatives to 5 percent by 2001.

For comparison, we construct two reference groups: (1) investor-owned utilities in Missouri and (2) investor-owned utilities in Iowa. Missouri is a neighboring state and its largest utility, Union Electric, is part of the Ameren group that owns the utilities serving a large portion of Illinois. Iowa is also a neighboring state, and its largest utilities serve part of northwest Illinois. Importantly, neither Missouri nor Iowa passed any deregulation measures in this period. Panel (a) of Figure 7 plots the share of own generation for Missouri utilities in red and for Iowa utilities in green. While deregulated firms in Illinois divested nearly all of their generation assets, the regulated firms in Missouri and Iowa continued to obtain the vast majority of their electricity from own generation.

Even though deregulated firms legally divested themselves of generation assets quickly, the actual restructuring of the upstream market came about more slowly. Panel (b) of Figure 7 plots the share of electricity obtained from affiliated companies, which combines both own generation and purchases from companies belonging to the same parent company. The share of purchases from affiliated companies did not fall until 2007. In practice, Illinois utilities split into subsidiary companies and signed long-term purchase agreements with each other at the time of divestiture. The last year of these contracts (2006) is indicated by the vertical dashed line. Even at the end of the sample, some fraction of the electricity is still purchased from affiliated companies, raising the possibility that aspects of vertical integration might still be at play in the market.

In the downstream market, consumers were slow to switch from the incumbent utilities due

Figure 8: Prices



Notes: Panel (a) displays the average wholesale purchase prices for utilities in Illinois, which deregulated, and Missouri and Iowa, which did not. Purchase prices reflect the quantity-weighted average price including long-term contracts and spot-market transactions. Panel (b) plots the retail prices for the same states. Retail prices are calculated based on all revenues to the utility and include transmission and delivery fees. The year 2006, which is the final year of several long-term contracts between affiliated companies and a retail rate freeze, is indicated by a vertical dashed line.

to the price caps that kept utility rates low. The price cap on rates expired in 2007, and many customers switched to independent power marketers in that year. Thus, effective deregulation, measured by the impact on market restructuring, did not occur in Illinois until roughly 2007, when most wholesale transactions were between independent parties and retail choice became much more common.

Though deregulation was expected to bring down prices, wholesale electricity prices in Illinois increased sharply in 2007, when deregulation had effectively taken place. This is illustrated in panel (a) of Figure 8. Before 2007, the quantity-weighted purchase price for deregulated utilities in Illinois followed a similar path to prices in Missouri and Iowa. After effective deregulation, prices in Illinois spiked, and then stayed above prices paid by regulated utilities.

Panel (b) of Figure 8 plots the downstream retail prices. The blue line in the plot shows that prices were steady from 1999 through 2006, which corresponds to the period that the rate freeze was in effect. At the expiration of the rate freeze, retail prices spiked. This increase was sudden and large relative to the price patterns observed in Missouri and Iowa.

The case study of Illinois illustrates how the effects of deregulation can be delayed for several years, even when legal measures such as vertical separation and competitive markets are introduced quickly. Firms have access to mechanisms (e.g., contracts and common ownership) to maintain a strong degree of vertical integration even when legal entities are vertical separated. We also find that the sudden increases wholesale and retail prices around the time of effective deregulation to be compelling evidence that deregulation served to *increase* prices for the affected states.

5 Market Power in Electricity Markets

The analysis of the previous section found that the restructuring of electricity markets resulted in higher prices for consumers, relative to those served by utilities in regulated states. Further, we find that markups increased in deregulated states, and that the increase in markups came primarily from upstream wholesale markets. There are two central economic mechanisms that could increase prices after restructuring. The first is the movement from regulated to marketbased prices, which allows suppliers to profitably increase prices above marginal costs. The second is double marginalization, which arises from the vertical separation of generation from retail services. This separation creates a wholesale market that allows generators to charge a markup in addition to a potential markup charged by retailers. Even if retailers charge no markup, this can result in higher prices because the retailers purchase energy at an additional markup instead of generating it in house. The extent to which these mechanisms will increase prices depends on how much market power firms have, since these effects could in principle be mitigated by increased competition. In this section, we present evidence supporting market power as the main driver for the increase in prices and markups realized in deregulated markets.

5.1 Upstream and Downstream Concentration

In this section, we use our detailed data, which provides a complete map of the corporate structure of the electricity industry, to accurately measure concentration at the wholesale and retail level over time.¹⁵ Our findings indicate that concentration among wholesale sellers has remained high over the last two decades despite significant changes in market structure. Concentration among wholesale buyers, on the other hand, has decreased over time, as expected with the introduction of retail competition, but it has remained high. These two effects combined are consistent with generators being able to charge high markups after restructuring allowed them to exert market power.

We evaluate changes in concentration in upstream and downstream markets by calculating the Herfindahl-Hirschman Index (HHI) for restructured and control states. We find that concentration remained high in the upstream market for sellers. Though utilities were forced to divest their generation assets, this did not result in a substantial reduction in concentration. In the downstream market, we find that concentration decreased substantially. Both forces—high concentration upstream and lower concentration downstream—could have increased wholesale prices (and markups) in restructured states. Decreasing concentration, or increased competi-

¹⁵We track ownership up until the ultimate parent company level.



Figure 9: Concentration Upstream and Downstream by Restructured Status

Notes: The figure shows the evolution of the mean HHI over time, where the HHI is computed at the state level for both buyers and sellers. Buyers include investor-owned utilities and power marketers, as reported in EIA data. Sellers include all firms that sell to an investor owned utility, as reported in FERC Form 1 data. For sellers, concentration is calculated at the parent company level.

tion, in the retail market could increase wholesale prices through a reduction in buyer power. Initially, utilities were by far the largest buyers in their local markets. After vertical separation, utilities could purchase from several generation owners, some of which were affiliated companies. Over time, as retail competition increased, utilities lost their market share in the downstream market (see Figure 6). We think this change in the relative balance of bilateral market power is part of the explanation of why markups grew in restructured states.

Panel (a) of Figure 9 shows the evolution of the mean HHI among firms that sell electricity to investor owned utilities, as reported in FERC Form 1. Sellers have been aggregated to the parent company level, such that if a utility reports purchasing from a certain power plant, and the plant is owned by Exelon, for example, we consider that transaction as a purchase from Exelon. Both deregulated and control states were highly concentrated at the beginning of our sample and remained so, with average HHI levels consistently above 3,000.¹⁶ Despite shifting an increasing share of energy to wholesale markets and encouraging independent generation, seller concentration did not decrease.¹⁷

Panel (b) of Figure 9 shows the evolution of the mean HHI among buyers for restructured and regulated states, where buyers include both investor owned utilities and power marketers. Concentration remained roughly constant between 1995 and 2015 in regulated states. In restructured states, on the other hand, concentration started falling in the late 1990s, when the

¹⁶The US Department of Justice considers an HHI above 2,500 to be "highly concentrated," and an HHI between 1,500 and 2,500 to be "moderately concentrated."

¹⁷Regulated utilities generate most of their energy, so concentration measures for sellers in regulated states describe very small markets. After restructuring occurs in deregulated states, concentration measures are more representative because a much larger share of the market is traded.

restructuring process started, and continued to do so through 2016. This pattern mirrors the increase in competition we observe in the retail sector. By the end of our sample, buyer HHI had crossed from the highly concentrated to the moderately concentrated range.

In summary, Figure 9 indicates that concentration among buyers decreased in restructured states, while seller concentration remained constant. This is consistent sellers maintaining a high degree of market power and provides an explanation for the large markups we observe when prices are deregulated. This correlation is not necessarily causal because market concentration is endogenous, but it suggests a potential mechanism behind our findings.

5.2 Elasticity of Demand

As a second check to confirm that our findings are driven by firms' market power, we examine how the effects on markups vary with the elasticity of the demand. Although we do not directly estimate the elasticity of demand, we observe the share of industrial, commercial, and residential customers served by each utility, which is highly correlated to elasticity. Residential customers are typically less responsive to prices, while industrial customers have higher electricity bills and more flexibility over the timing of their consumption, which makes them more sensitive to prices (Fan and Hyndman, 2011; Burke and Abayasekara, 2018). In line with this categorization, retail competition has generally resulted in greater switching for industrial customers, while residential customers face significant switching and search costs and stay longer with the incumbent provider (Hortaçsu et al., 2017). Importantly, the proportions of each group in a utility service area are arguably exogenous since for the majority of households and businesses electricity expenses are not significant enough to be a determinant factor in their location decisions. Consistent with this hypothesis, we find larger effects on markups for utilities that have a relatively higher share of residential customers or a lower share of industrial customers.

We examine the relationship between the estimated effect on markups and the share of residential or industrial customers in the area served by a given utility, which is strongly correlated with the elasticity of the demand faced by the utility. Table 3 presents results from regressing the estimated effect on markups on the share of residential or industrial customers in a utility's area in 1999, using observations between 2006 and 2016. The sample is restricted to this period because this is when markups changed and we are interested in the mechanism behind this change. We use the value in 1999 because it is not affected by the prices charged by the utility in subsequent years. This provides a clean proxy for the elasticity of the demand in that market. We analyze the relationship between markups and demand elasticity using both wholesale markups and net markups, which are retail prices minus fuel costs, and find similar results for both measures.

Results in Table 3 indicate that utilities with a higher share of residential customers in 1999, which is associated to a more inelastic demand, had larger increases in markups. The opposite

	Net Markup		Wholesale Markup	
	(1)	(2)	(3)	(4)
Share Residential 1999	119.3***		68.02**	
	(19.19)		(21.40)	
Share Industrial 1999		-76.14***		-41.75***
		(9.266)		(10.15)
Constant	-24.92**	38.26***	-20.27*	14.91*
	(8.074)	(6.177)	(8.538)	(6.008)
Year FE	Yes	Yes	Yes	Yes
Observations	746	746	622	622
R^2	0.056	0.089	0.027	0.034

Table 3: Markups and Demand Elasticity

Notes: *** p < 0.01; ** p < 0.05; * p < 0.1. The sample contains observations at the utility level between 2006 and 2016. The regressions use MWh sold in 1994 as weights.

is true for the share of industrial customers, which is linked to a higher elasticity of demand.¹⁸ These findings are consistent with deregulated firms exerting market power, charging higher markups in markets with less elastic demands.

5.3 Heterogeneity in Effects by Customer Type

To further investigate the potential role of market power, we examine the effects of deregulation on different types of customers. We consider the three primary classes of electricity customers: residential, commercial, and industrial. To isolate the effect arising from the upstream market, we focus on bundled service rates available from local utilities. Though deregulation allowed for market-based prices, utilities that continued to operate in these retail markets were required to offer prices based on average variable costs. In effect, these utilities offered a price equal to the cost of procurement from the wholesale market, plus additional fees to cover the fixed costs of distribution.

Observing similar changes in these rates across different classes of customers would be consistent with the exercise of market power in the wholesale market. Upstream generation facilities have little ability to price discriminate across different types of customers when selling to a utility, which bundles demand across customer types. If we observed instead that, for example, residential customers saw much greater increases in prices, we might infer that greater market power is exercised in downstream markets, where retailers can easily distinguish among types of customers. Alternatively, differential changes by customer type may also indicate special fees or subsidies provided as a result of deregulation to specific types of customers.

Figure 10 plots the difference-in-difference matching estimates of changes in utility retail

¹⁸ We use median regressions to confirm that results are not due to extreme observations; these are presented in Table 5 in the Appendix.



Figure 10: Effects on Utility Rates by Customer Type

Notes: Figure displays difference-in-differences matching estimates of changes in bundled service retail prices for deregulated utilities. These prices are determined by procurement costs for the utilities. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to 1999, which is the year prior to the first substantial deregulation measures. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

prices by customer type. Overall, we find similar effects across different types of customers. All three types observe statistically significant increases in prices, with an average effect between 10 and 15 dollars per MWh from 2009 through 2016. Consistent with cost-based regulation of these prices, these effects very similar to the change in utility variable costs we report in panel (a) of Figure 5, which also average between 10 and 15 dollars per MWh over the same period. Overall, the fact that we observe similar increases in cost-based prices across customer types further suggests the important role upstream market power to increase prices in deregulated markets.

One notable difference is that commercial and industrial customers realized price increases as early as 2001, whereas residential prices did not begin to increase until 2006. This is consistent with practice of implementing rate freezes along with deregulation, which fixed rates at pre-deregulation levels. Rate freezes were disproportionately targeted toward residential and small commercial customers. Thus, in many states, large commercial and industrial customers were immediately subject to the changes in variable costs realized by utilities in the aftermath of deregulation. We discuss the increase in utility variable costs and the rate freezes in more detail in Sections 4.3 and 4.4, respectively.

Consistent with our findings above, industrial and commercial customers are much more likely to switch away from the regulated utility rates. This transition was gradual, in contrast with the sudden increase in prices we observe.¹⁹ See Figure 18 in the Appendix for estimated effects on the consumption of bundled service from the incumbent utility by customer type.

¹⁹With the exception of Texas and Maine, which fully eliminated regulated rates for some utilities.



Figure 11: Share of Sources from ISOs

Notes: Figure displays the shares of sourced electricity obtained from ISO wholesale markets, for utilities in deregulated and control states. The residual shares are composed of own generation and bilateral contracts with electricity suppliers.

6 Possible Alternative Explanations

In this section, we discuss other events that had an impact on electricity prices and costs that could potentially play a role explaining our findings. Overall, we find that the weight of the evidence points the substantial role of market power in explaining the increase in prices and markups that we observe in deregulated states.

6.1 ISO Markets

During the restructuring process, transmission assets covering areas much larger than a single utility's service area were put into the hands of an independent operator. This served two purposes: First, to grant easier access to independent generators who wanted to sell energy into the market. Second, to allow for trade across larger areas as a potential channel to reduce costs by sourcing energy from low cost plants. Evidence indicates that central dispatch by regional transmission operators has indeed reduced costs (Cicala, 2017).

Our findings suggest that market power in the wholesale market started increasing shortly after ISO organized markets started operating.²⁰ Nonetheless, there are several reasons why the opening of centrally dispatched electricity markets is unlikely to lead to the observed increase in market power. First, we would expect ISO markets to strengthen competition rather than weaken it, since they connect a larger number of players and have transparent market clearing prices. Second, even if they increase generators' market power, the share of electricity that utilities purchased from ISOs in those early years was fairly low, not reaching 10 percent until 2010, as Figure 11 shows. Lastly, ISO markets are not exclusive to restructured states. For

²⁰For example, the Midwest market (MISO) started operating in 2005 and the New England ISO in 2004.



Figure 12: Transition Charges and Stranded Costs

Notes: Figure displays the transition charges levied on customers in deregulated utilities to cover stranded costs and other features of restructuring. Panel (a) plots the mean charges (green line) and the condition mean for positive charges (dashed purple line). Panel (b) plots the count of utilities with reported transition charges (green line) and the count of utilities with positive charges (dashed purple line).

instance, only 2 of the 10 states belonging to MISO in 2005 were restructured, and MISO is the second largest ISO after PJM. Since our analysis compares utilities in restructured and regulated states, we think that it is unlikely that the observed difference in market power would come from ISO purchases.

6.2 Stranded Costs

During restructuring, most utilities reached agreements with state regulatory authorities to levy additional charges on their customers related to the move toward deregulation. A common argument by the utilities was that the transition to competitive markets would result in a loss in value of their capital investments, and that they should be compensated for the "stranded" costs of these assets. One question is whether the increase in rates we observe reflects the these additional charges.

We collected information transition charges, which covered stranded costs, for 44 large utilities across 16 states that were treated with deregulation measures.²¹ Most of the utilities for which we obtained data levied additional transition charges on their customers; only 6 of them never implemented transition charges. Transition charges were initially very high and decline throughout our sample period. Panel (a) in Figure 12 shows the mean of these additional charges over time. This decline holds even if we condition the mean on utilities with positive stranded costs in each period, thus dropping utilities as their window for stranded cost recovery ends.

²¹The data were obtained from utility ratebooks or the relevant state regulatory commission.

Figure 13: Share of Generation from New Renewable Resources



Notes: Figure displays share of generated electricity from renewable resources in deregulated and control states. The plot reflects wind, solar, and geothermal sources. Hydropower is excluded because RPS requirements have had little impact on hydropower sources.

As shown in panel (b), individual utilities phase out stranded costs starting in 2006. The green line shows the count of utilities for which we have stranded costs measures, and the purple dashed line shows the count of utilities with positive costs.

Thus, coinciding with the time we observe effective deregulation and large markup increases, we observe declines in stranded costs and transition charges, with many utilities phasing them out altogether. Though we do not have a complete panel of all stranded costs, we find it very unlikely that they account for the observed increase in prices in deregulated states. The trends in stranded costs move the opposite direction from the price changes we observe; if anything, these costs may mask some of the underlying changes to the economics of the market.

6.3 Renewable Portfolio Standards

Renewable portfolio standards (RPS) require utilities to procure a minimum share of the electricity they sell from renewable sources. RPS have the potential to increase prices (Greenstone et al., 2019) and might have contributed to increase utilities' costs, since 25 states had passed regulation with this kind of requirement by 2007.

We think RPS are an unlikely explanation for our results. First, although RPS were more common among restructured states, those that remained regulated adopted them as well. For example, we find that markups and prices started to diverge around 2006. In 2007, 14 restructured states and 8 regulated states had adopted RPS. Since our analysis compares utilities in restructured states to those in regulated states of a similar size and fuel mix, we do not expect RPS differentially affecting the two sets of utilities to be a significant source of concern.

In addition, RPS has resulted in a gradual increase in share of generation coming from renewable sources. At the point of adoption, the requirements put in place by RPS were not stringent. To illustrate this, Figure 13 shows the share of generation coming from renewable resources—wind, solar, and geothermal—in deregulated and control states.²² The figure shows that the shares are nearly identical across the two groups, and they increase at the same gradual rate starting in 2008.

6.4 Other Cost Shocks

Since the restructuring process started, the electric industry has received several cost shocks from two main sources: fuel prices and environmental regulation. How these shocks affected a utility's cost structure depends on the utility's initial fuel mix since, for instance, more stringent environmental regulation will have a stronger effect on costs for utilities that rely more heavily on coal to produce electricity. A potential concern would then be that this initial difference in fuel mix determined how firms were affected by cost shocks, and not the restructuring process.

Our matching approach allows us to deal with this concern, since each utility in a restructured state is compared to utilities in regulated states with a similar fuel mix in 1994. Though this allows us to compare utilities that in principle would be similarly affected by these cost shocks, our empirical approach remains vulnerable to variation coming from changes in the fuel mix that took place after 1994. We do not necessarily want to control for entry and exit decisions that took place after the deregulation process had started, as these decisions may have been caused by the deregulation process. If, for instance, deregulated markets attracted more entry by cleaner plants, or by gas plants that could take advantage of the cheaper gas, this is something that we we can include in our estimates of cost efficiencies. In our data, we observe similar trends in aggregate generation by fuel types across the two groups.²³

A related concern is that plants may choose emissions compliance strategies that differentially affect their cost structures. Fowlie (2010) compares compliance strategies between restructured and regulated coal plants in response to an emissions trading program introduced in 2006 to regulate NO_X , an ozone precursor. The program affected plants in 19 states, of which 12 were restructured. Because rate-of-return regulation creates stronger incentives for capital investment, regulated plants chose more capital intensive compliance options than plants in restructured states. This implies that environmental regulation could potentially have increased fixed cost for regulated plants and variable costs for restructured plants. If compliance is met by variable costs that we do not measure, we could potentially overstate the changes in markups in restructured states. Despite this, compliance costs would not likely explain the large magnitudes that we observe. Engineering estimates of operating compliance costs taken from Fowlie (2010) indicate that the maximum difference between common compliance technologies is around 7.5 dollars per MWh, which is much less than the markup increases that we

²²Hydropower is excluded because hydropower plants were not the target of RPS requirements. From 2001 through 2016, the share of hydropower generation has remained roughly flat across deregulated and control states.

²³The only meaningful difference in our data is that control states became relatively less reliant on coal and more reliant on natural gas during our sample period.

find (see Figure 4). Moreover, these costs are not much more than the decrease in fuel cost in restructured utilities over that period (see Section 4.3). Thus, such regulations are not likely to generate large increases in variable costs in restructured states.

7 Conclusion

We present a detailed analysis of the evolution of electricity prices and costs from 1994 until 2016. Our analysis spans the implementation of state-specific deregulation measures that began in the late 1990s, which included the introduction of market-based prices. Compared to utilities in states that stayed regulated, deregulated utilities realized higher prices but lower costs. Overall, markups increased substantially. Our findings are consistent with the exercise of market power in deregulated markets.

For our analysis, we construct a unique firm-level dataset that includes firm-to-firm transactions and common ownership. We find that changes in prices and markups increased over time because long-term contracts and common ownership delayed the intended changes in vertical market structure. This delay in *effective deregulation* may partially explain why some previous research has found no significant effect on prices. In this sense, our research highlights the importance of accounting for intermediate degrees of vertical integration to understand the consequences of deregulation in the electricity sector.

This paper argues that electricity prices increased after deregulation because of the presence of market power. The restructuring of the electricity sector vertically separated utilities into distinct entities for generation and retail, allowing for double marginalization and potentially increasing prices by more than if utilities had remained integrated. We find the largest increases in wholesale markups, which is consistent with the evolution in concentration we observe upstream and downstream. Generators remained concentrated despite a transfer of ownership, while utilities lost monopsony power in wholesale markets with the entry of competitive retailers. Our findings do not necessarily imply that electricity markets should remain regulated, but rather emphasizes the importance of careful oversight of deregulated markets and the consideration of market power in market design. Further research is needed on how to organize markets such that consumers can benefit from lower prices, as well as understanding the longer-run effects of deregulation that arise from changes in investment and environmental compliance efforts.

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Appendix

A Details of Dataset Construction

In this section, we report details of how we constructed the dataset.

A.1 State-Specific Deregulation

To measure the impact of deregulation, we divide our sample into utilities in states that allowed for market-based electricity prices and those in states that continued with a state-sponsored monopoly and regulated rates. States that allowed for market-based electricity prices also enacted restructuring measures to allow for competitive entrants in the generation market (upstream) and in the retail market (downstream). Typically, incumbent utilities in deregulated states were no longer permitted to own generation facilities, but they were allowed to continue to operate downstream. Thus, retailers in deregulated states had to obtain electricity from a wholesale market, and consumers could choose between a regulated rate from the incumbent utility and market-based prices from independent retailers.

For each state, we identify whether deregulation measures were enacted, and when the measures legally came into effect. The 17 states that implemented deregulation measures in our period (1994–2016) are reported in Table 4, along the year of implementation. Upstream deregulation measures correspond to the vertical separation of a utility from generation facilities as well as an explicit allowance of competitive electricity suppliers. Downstream deregulation measures correspond to the introduction of a market for alternative retail supplier. All of the states implemented these measures between 1998 and 2002, and the upstream and downstream legal changes typically occurred at the same time. Michigan is a notable exception, as they allowed for downstream competition but did not restructure the upstream market.

Five states—Arizona, Arkansas, Nevada, and Montana—initially passed deregulation measures but later rescinded them. We remove these four states from our analysis. We focus on investor-owned utilities (IOUs) that generated electricity in 1994. Because Nebraska and Tennessee do not have utilities that meet these criteria, we also remove them from the analysis.²⁴ We are left with 17 states that introduced competitive markets and 25 states that did not. Our main sample consists of 78 treated utilities that were subject to deregulation measures and 75 utilities control utilities that were not.

²⁴Nebraska does not have IOUs in this time period. In Tennessee, all generation comes from the federally operated Tennessee Valley Authority.

State	Implementation Year		
NY	1998		
RI	1998		
CA	1999		
NH	1999		
MA	1999		
ME	1999		
СТ	2000		
DE	2000		
MD	2000		
NJ	2000		
PA	2000		
IL	2001		
OH	2001		
MI	2002		
OR	2002		
ΤX	2002		
VA	2002		

Table 4: First Year of Deregulation, by State

Notes: Table indicates the year initial deregulation measures came into effect for the listed states. For most states, this corresponds to when utilities began to divest generation assets. Michigan (MI) is an exception that did not pass a measure to deregulate the upstream market. Four states (AZ, AR, NV, and MT) initially passed deregulation measures but later rescinded them. These four states are omitted from our analysis.

B Supplemental Tables and Figures

B.1 Investor-Owned Utility Service Territories

Figure 14: Areas Served by Investor-Owned Utilities



Produced by Edison Electric Institute. Data Source: ABB, Velocity Suite. October 2018

Notes: Figure displays the geographic service territories for investor-owned utilities in our sample as of 2018. Source: Edison Electric Institute.

B.2 Comparison of Event Timing Approaches



Figure 15: Different Choices of Timing

Notes: Figure displays difference-in-differences matching estimates of changes to incumbent utilities share of quantity demanded provide by its own generation. Panel (a) displays the results in calendar years, following the results in the main text. Panel (b) displays the results indexed to time period 0, which represents the year prior to the implementation of deregulation measures in each utility's state. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.



Figure 16: Event Study Estimates of Changes in Prices and Costs After Deregulation

Notes: Figure displays difference-in-differences matching estimates of changes in (a) retail prices and (b) fuel costs for deregulated utilities. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to time period 0, which represents the year prior to the implementation of deregulation measures in each utility's state. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.

B.3 Statewide Costs





Notes: Figure plots the statewide average fuel costs of generation for all generating facilities in deregulated states (solid blue line) and control states (dotted red line). The red dashed line plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

B.4 Price Sensitivity Analysis

	Net Markup		Wholesale Markup	
	(1)	(2)	(3)	(4)
Share Residential 1999	60.38***		47.16***	
	(9.677)		(11.76)	
Share Industrial 1999		-33.82***		-31.67***
		(7.038)		(9.488)
Constant	-15.79***	15.67***	-18.98**	3.416
	(4.384)	(2.705)	(6.035)	(5.005)
Year FE	Yes	Yes	Yes	Yes
Observations	746	746	622	622

Table 5: Markups and Demand Elasticity

Notes: *** p < 0.01; ** p < 0.05; * p < 0.1. Results from median regressions using a sample of observations at the utility level between 2006 and 2016. The regressions use MWh sold in 1994 as weights.



Figure 18: Change in Incumbent Utility Retail MWh (Bundled Service)

(c) Industrial

Notes: Figure displays difference-in-differences matching estimates of changes in log MWh for bundled service for deregulated utilities. Bundled service customers are those remaining on regulated rates in deregulated areas. We exclude Texas and Maine, which fully eliminated bundled service. Each deregulated utility is matched to a set of three control utilities based on 1994 characteristics. The estimated effects are indexed to 1999, which is the year prior to the first substantial deregulation measures. The dashed lines indicate 95 confidence intervals, which are constructed via subsampling.