The US Electricity Industry After 20 Years of Restructuring

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Abstract

Electricity restructuring in the 1990s ended the era of vertically integrated monopolies in many states, allowing nonutility generators to sell electricity to utilities and, in fewer states, allowing retail service providers to buy electricity from generators and sell to end-use customers. We review the economic arguments for restructuring and the resulting effects in subsequent years. We argue that the greatest political motivation for restructuring was rent shifting, not efficiency improvements. Although electricity restructuring has brought efficiency improvements, it has generally been viewed as a disappointment because the price-reduction promises made by some advocates were based on politically unsustainable rent transfers. In reality, electricity rate changes since restructuring have been driven more by exogenous factors, such as generation technology advances and natural gas price fluctuations, than by restructuring. We argue that a similar dynamic underpins the current political momentum behind distributed generation, primarily rooftop solar photovoltaic systems, which remains costly from a societal viewpoint, but privately economic owing to the rent transfers it enables.

1. INTRODUCTION

In the mid-1990s, the great majority of electricity customers in the United States were served by a vertically integrated, monopoly utility, an investor-owned utility (IOU), that provided generation, transmission, local distribution, and billing/collections.[1] IOUs were closely regulated by state-level public service commissions under cost-of-service regulation, in which utilities were effectively guaranteed the recovery of prudently incurred operating costs plus a regulated return on capital expenditures. In the seven years between 1995 and 2002, a wave of major regulatory reform aimed at introducing competition into various utility functions, known broadly as electricity restructuring, transformed the industry.[2] These changes followed closely on the heels of what was seen as the successful economic deregulation of many other industries, including airlines, railroads, telecommunications, gasoline retailing, and the production of oil and natural gas.

At the time, it was widely expected that this transformation would eventually lead the entire industry to a less regulated and more market-based structure. Yet in the years following 2002—after the 2000–2001 electricity crisis in California's restructured market—the movement for electricity deregulation encountered a significant backlash. Although there was some debate over rolling back deregulation, public policy after 2002 is more accurately described as a cessation of any further restructuring. For the past decade, the policy focus for the electricity industry has turned elsewhere, mostly toward environmental concerns, and the loud debates from the early 2000s over the merits of restructuring have been reduced to a background murmur.

The central premise of this article is that views of restructuring in the electricity industry over the past two decades have been driven primarily by the pursuit of quasi-rents that have resulted from investments in generation capacity, power purchase agreements, and other strategies whose payoffs are revealed over long time periods. These strategies create fluctuations in the relationship between the average cost and marginal cost of producing and delivering electricity to consumers. Average cost is the basis for price setting under regulation, whereas marginal cost is the basis for pricing in a competitive market. During periods in which these two costs have diverged, consumer and political sentiment has tilted toward whichever regime (regulation or markets) offered the lowest prices at that time.

The relationship between average and marginal cost in the industry is in turn influenced by many factors. Some of these—such as productivity, the level of investment, and the choice of type of investment—are influenced by the transitional incentive problems attributed to cost-of-service regulation. Others are influenced by factors largely beyond the control of state utility commissioners. Two critical exogenous trends during this period have been technology innovations adapted from other sectors (e.g., aircraft engine technology that changed the design of gas turbines and semiconductor innovations that reduced the cost of solar power) and trends in the prices of natural gas, which is generally the fuel setting marginal costs in most electric systems.

Thus, although the restructuring era dawned with great hope that regulatory innovations, and the incentives provided by competition, would dramatically improve efficiency and greatly lower consumer costs, that hope was largely illusory. In fact, rates rose in both regulated and deregulated

[1]More than 75% of end-use electricity was provided by IOUs. Most other customers received electricity from publicly owned municipal utilities or, in some rural areas, local cooperatives (see US Energy Inf. Admin. 1995).

[2]Throughout this article, we use the term restructuring to describe the suite of changes that impacted both the organization of electricity firms and the methods by which those firms were regulated.

states, and rose more rapidly in the deregulated ones in the early years of reform. Subsequent studies of retail rates in both groups of states have generally overlooked the key point that exogenous shocks to the industry often dominated the incremental benefits that regulatory reform can provide. There is clear evidence that competition has improved efficiency at power plants and improved the coordination of operations across a formerly balkanized power grid. But gas price movements and new technologies have had a far larger impact.

We argue that many of the same incentives that created political momentum for restructuring 20 years ago are still present in the industry. One way they manifest today is in the increasing focus on distributed generation (DG), the term generally used for electricity generation that takes place on the customer side of the meter and reduces the customer's retail electricity demand from the utility. Although valid economic and technological arguments can be made for and against an expanded role for DG, transfers of quasi-rents play a major role in the policy positions.

In Section 2, we review the expectations that drove the push for electricity restructuring in the 1990s and how those beliefs shaped the market-based models for electricity markets in each vertical component of the industry: generation, transmission, distribution, and retailing. In Section 3, we examine the evidence on what effect restructuring has actually had, as well as common arguments that confound electricity restructuring with changes in input costs and other factors. Section 4 looks ahead to the most pressing challenge the industry will face in the coming years, the increasing role of renewable and intermittent energy sources, both from utility-scale generation plants and from much smaller-scale DG at households and commercial customers. We conclude in Section 5.

2. THEORY AND IMPLEMENTATION OF ELECTRICITY RESTRUCTURING

One of the challenges for an analysis of electricity restructuring is that there are several competing definitions of what restructuring or deregulation actually is. Outside the United States, a key step in electricity restructuring was the divestiture of the government-owned assets that had composed a nationalized power sector. In the United States, government ownership was never the dominant form of organization, and the exceptions—federally marketed hydroelectric power and municipally owned generation and distribution companies—have remained largely unchanged during the restructuring era. Technically, wholesale electricity markets are still regulated by the Federal Energy Regulatory Commission (FERC) under the authority granted by the 1935 Federal Power Act. The wave of state-level restructuring did not change this fact, although the FERC has applied its authority flexibly by allowing states and regions to set market-based rates. Such authority can be revoked, however, so it is inaccurate to label even wholesale markets in fully restructured regions as deregulated.

In a market-based system for electricity provision, the industry is generally considered as participating in four separate activities: the generation of electricity, long-distance transmission over high-voltage lines, voltage step-down (to the 110 V common in the United States or 220 V used in Europe and elsewhere) and local distribution to end users, and retailing (marketing and resale of wholesale power) to end-use customers. The last activity includes the procurement of power under long-term contracts, rate setting, billing, and collection. The US restructuring process was focused on generation, transmission, and retailing. The local distribution lines continued to be considered a natural monopoly that would be subject to either regulation or municipal ownership.

Changes to generation, transmission, and retailing were pursued with varying levels of commitment in different parts of the country. Independent oversight and control of the transmission networks were viewed by many as the backbone of restructuring because transmission was critical both to generators accessing a competitive wholesale market into which they could sell and to retailers accessing competitive sellers from which they could buy. The restructuring of generation resembled most closely the deregulation that had taken place in other industries, with the free entry of unregulated electricity plants [known as merchant generators or independent power producers (IPPs)] that would live or die by their cost of production and the price they could get for their output. Finally, retail restructuring, in the limited areas it has taken hold in the United States, has allowed nonutility companies to become the wholesale procurement entities for retail customers, offering customers alternative retail pricing structures, although across a rather limited spectrum, as we discuss below.

In theory, at least, the three aspects of restructuring were closely intertwined. Without the independent oversight of transmission, a merchant electricity plant would be at the mercy of the local transmission owner, who could extract large shares of the quasi-rents available once the plant was built, thereby discouraging the entry of competitive generation. Even with transmission access, a merchant generator would be in a very weak position if there were only one retail electricity provider to which it could sell its output. A monopoly retail provider (a distribution utility) could still engage in competitive procurement, but that creates a narrower spectrum for competitive generation, and it means that the monopoly retailer is the single determinant of the range of products that might be procured for retail. For instance, the monopoly retailer might not pursue low-carbon sources even if there are many retail customers who would be willing to pay a premium for greener energy. Thus, retail competition potentially makes competitive generation more viable. Likewise, competitive generation is central to the retailer being able to offer better procurement options, different generation sources, or alternative billing mechanisms, which the retailer would likely want to balance with the wholesale contracts it has with producers.

In practice, although the pursuit of restructuring in the three activities has been regionally correlated, many areas have developed generation restructuring without retail competition. Additionally, independent transmission operators have taken over large swaths of the US grid in which both generation and retail competition vary greatly.

2.1. Transmission Access Reforms

Transmission restructuring proceeded along two paths, a regulatory path that attempted to impose rules upon vertically integrated utilities that would promote third-party access to their networks and an institutional path that encouraged the creation of independent system operators (ISOs) and later regional transmission organizations (RTOs).[3] Through a series of orders during the 1990s and 2000s, the FERC attempted to force the creation of more transparent online marketplaces for available transmission capacity and to require vertically integrated utilities to provide transmission service to third-party IPPs. These efforts have achieved at best mixed success.

The more successful path to nondiscriminatory grid access appears to have been the creation of RTOs and ISOs. These entities are organized as user-supported nonprofit companies and operate essentially as regulated entities overseen by the FERC. In the United States, these transmission companies do not own the transmission assets in their jurisdictions, but rather they control access to those assets by virtue of approving, and in some cases setting, the production schedules of the power plants within their regions, as well as operating real-time balancing markets that adjust supply as needed to maintain network reliability. In each case, the decisions made by the ISOs with regard to generation operations are dominated by a mandate to respect the constraints of the transmission network and other reliability considerations. Unlike vertically integrated network

[3]Both types of organizations are tasked by the FERC to coordinate the investment and operations of regional power grids in a nondiscriminatory, transparent manner.

entities, ISOs have no generation assets or retail consumers and are therefore credibly impartial as to specific market outcomes, as long as those outcomes do not threaten reliability.[4]

Initially, the RTO/ISO model was largely restricted to markets undertaking the full suite of restructuring steps described in this section. The full and unfettered access of disparate power producers to the available population of electricity customers dictated an institutional structure that would eliminate concerns over vertical barriers. Conversely, jurisdictions that wanted no part of retail competition were equally suspicious of the RTO/ISO structure as an initial step down the slippery slope to full restructuring. Thus, many municipal utilities and some of the largest and strongest integrated utilities, as well as federal power marketing agencies, kept their transmission systems organized along traditional structures in which they directly controlled access and real-time use.

This changed in the latter half of the 2000s. As we discuss below, the pressures to restructure other aspects of utility operations receded in many regions, so joining an RTO/ISO market no longer implied the inevitable dissolution of the traditional utility franchise. At the same time, the benefits of the better coordination of operations and lowering of transaction costs within ISOs appear to have been substantial (see Joskow 2006, Wolak 2011b, Mansur & White 2012). **Figure 1** illustrates the geographic reach of North American ISOs and RTOs as of 2012. Currently, RTOs such as the Midcontinent Independent System Operator, Southwest Power Pool, and PJM each contain several states that never seriously considered restructuring their generation or retail sectors.

The creation and expansion of the RTO/ISO model may be the single most unambiguous success of the restructuring era in the United States. The United States has historically suffered from a utility system that was highly balkanized relative to most other countries. The evidence suggests that the lack of coordination across utility control areas impeded Pareto-improving trades worth billions of dollars (see White 1995, Joskow 1997, Kleit & Reitzes 2008, Mansur & White 2012). Although the early momentum for aggregating utility control areas into more regionally managed RTOs was provided by the belief that it was a necessary step toward the ultimate goal of deregulating generation and retail, the expansion of the RTO structure has come to be viewed as a valuable legacy of this period, even for states that never showed serious interest in these other aspects of restructuring.

2.2. Restructuring of Generation Ownership

The second dimension of restructuring impacted the ownership status and remuneration of generation assets. Large amounts of generation capacity were converted from utility status to IPP (nonutility or merchant) status. Effectively, these assets transitioned from a cost-of-service regulation model, in which they were compensated based on average production cost, to a market-based pricing model, under which these assets earned a market price for the output they were able to produce.

To the extent one considers the electric sector to be deregulated, it is a result of this fundamental shift in the paradigm for compensating owners of generation. In addition to the divestiture of much of the existing generation fleet previously owned by IOUs in restructured states, an equally dramatic change impacted the investment in new generation. The construction of generation assets was no longer coupled with a guarantee to recover a positive return on those capital costs. In 1997, only

[4]Indeed, RTOs and ISOs have at times been criticized as being too exclusively focused on reliability and not sufficiently concerned with the costs their instructions and mandates placed on the customers and generators operating within their systems. It is true that the performance of ISOs is generally measured in terms of the reliability of their systems and the costs of the relatively narrow scope of operations directly housed within ISOs, rather than in terms of the indirect effects their decisions may have on productivity and prices.

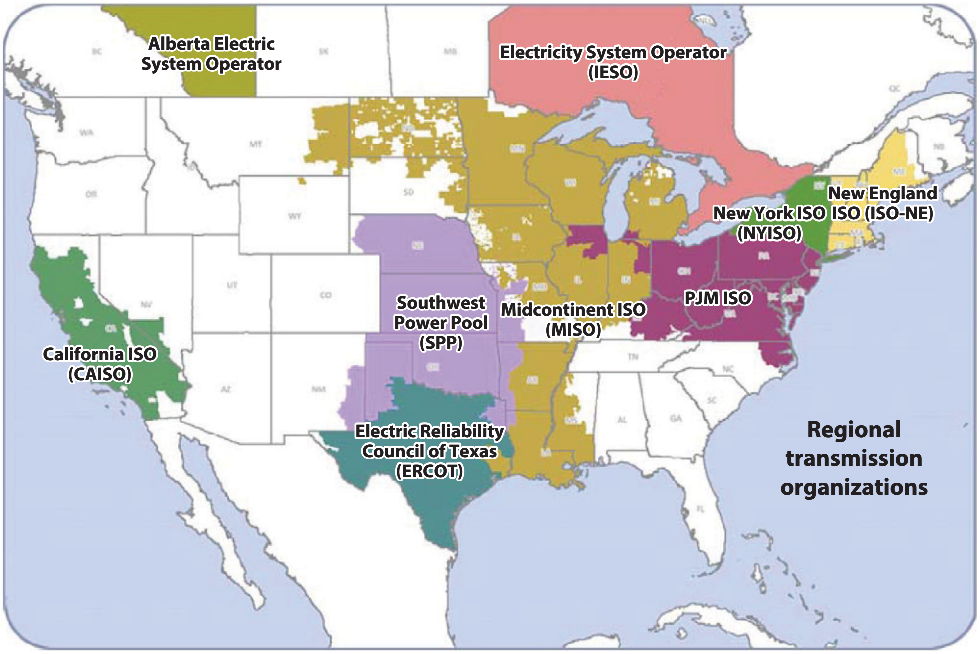

Figure 1

US independent system operators (ISOs) and regional transmission organizations as of 2012. Figure created using Energy Velocity, July 2014.

1.6% of US electricity was produced by generation owned by firms classified as IPPs. That figure rose to 25% by 2002 and was just under 35% in 2012. The share of nuclear generation owned by IPPs rose from zero in 1997 to almost 50% in 2012, as utilities sold off their nuclear assets.

Figure 2 displays the diversity of ownership patterns across the United States as of 2012 and illustrates the strong regional pattern of generation restructuring. The Southeast, with its large and regionally powerful IOUs, and much of the Pacific Northwest, with its dominance of federally operated generation and municipal utilities, have largely resisted changes in generation ownership. Importantly, these regions also enjoyed some of the lowest average retail rates in the country in 1997. The Northeast and Illinois have almost fully transitioned to a nonutility form of ownership, and Texas, California, and Montana have also seen large shares of IPPs.

As discussed below, we consider this dimension of restructuring to be the most economically meaningful in its consequence. This is mainly because the majority of costs—and the most potential variation in costs and prices—still reside in the generation sector. Political attitudes toward the effects of restructuring during the past 20 years have also been dominated by outcomes in the generation sector. These attitudes can largely be captured by comparing average to marginal costs.

In the early 1990s, just prior to the initial years of restructuring, much of the country experienced large generation reserve margins (see **Figure 3**). Until the past few years (with the rise of intermittent renewable generation), this statistic was a very good proxy for measuring the efficient deployment of capital. Larger reserve margins generally imply installed capacity (and capital) that is underutilized. Lower utilization implies higher average costs as the capital expenditures are spread across a smaller consumer base. Lower utilization rates also often imply that generation with relatively low marginal cost is often available, and marginal, thereby contributing to

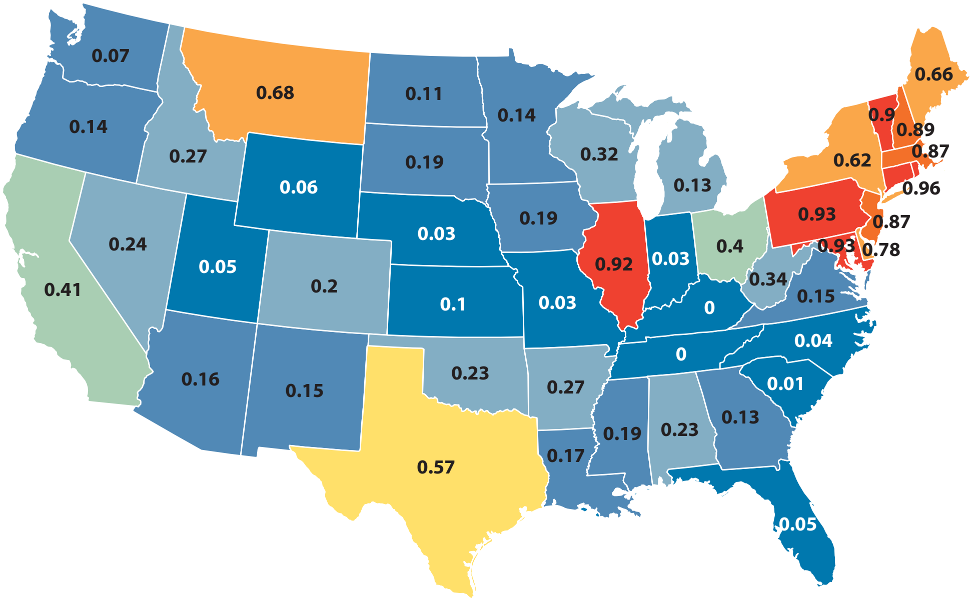

Figure 2

Share of output from merchant generators in 2012.

relatively low regional wholesale prices. Historically low natural gas prices during the 1990s also greatly contributed to low regional wholesale prices.

The industry during the late 1990s was therefore experiencing very high reserve margins, leading to unusually low marginal costs and unusually high average costs. This is the fundamental source of the pressure for restructuring. Although, as discussed above, much of the rhetoric at the time focused on retail deregulation, this needs to be seen from the perspective of customers (often large industrial customers) who saw great opportunity in being able to gain direct access to the wholesale market.[5]

Of course, what appeared as a great opportunity for customers conversely created a real threat to utilities who were the residual claimants on generation assets for which the market value in a competitive wholesale market would have been well below the depreciated capital value that remained on the utilities' books at the time of restructuring. This fact was quickly internalized by equity markets. Share prices of the largest utilities in California, Pennsylvania, and New England experienced sharp declines during the mid-1990s. The concern among holders of utility stocks soon gave way to a period of reflection and negotiation over an acceptable transition from an average-cost to market-based pricing paradigm. The political and regulatory process was forced to confront the uncomfortable fact that much of the consumer appeal of restructuring was rooted not in cost savings and productivity gains, but rather in an opportunity to shift responsibility for paying the sunk costs of what were considered uneconomic stranded assets. This meant that immediate consumer savings were largely dependent on an equivalent reduction in returns for utility shareholders. This is an important theme we return to when we examine the current rhetoric about the utility of the future in Section 4.

[5]In Borenstein & Bushnell (2000), we point out this tension between efficient economic decision making and incentives for rent shifting.

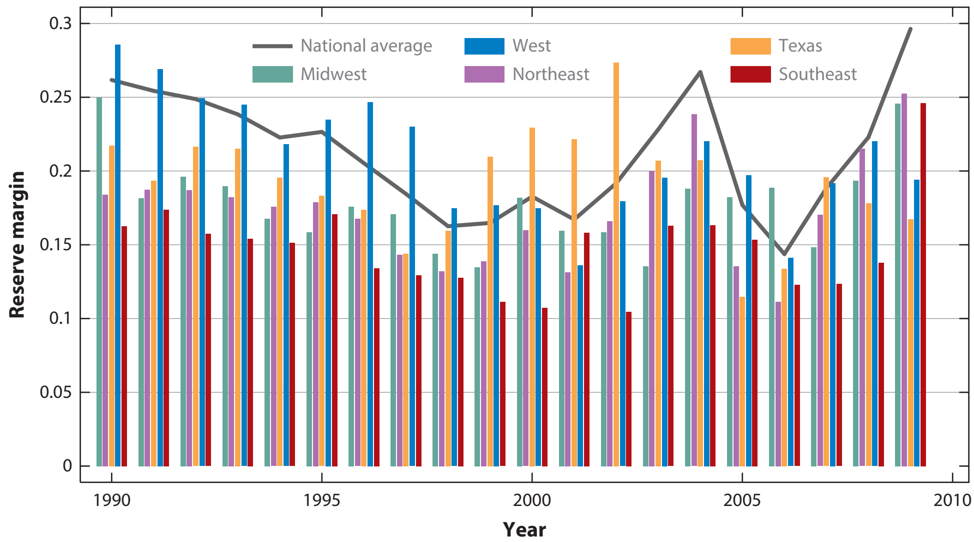

Figure 3

Generation reserve margins in the United States.

In the end, utilities in all restructuring states persuaded regulators that the implicit agreement between the regulator and the IOU (commonly referred to as a regulatory compact) required that the utility be made whole for any lost asset value from restructuring. Nearly all the generation assets with market value below the IOU's remaining book value had been built with the approval, and in some cases mandate, of regulatory commissions,[6] so it was generally concluded that forcing restructuring without compensation for stranded assets would violate the regulatory compact. Most state restructuring schemes included a plan for 100% recovery by utilities of any stranded investment, and the others aimed at nearly 100% recovery.

The most common mechanism for recovering stranded costs was to allow a transition period in which portions of utility retail prices would be frozen at what were then considered to be above-market rates. Utilities would therefore be allowed to apply these excess retail margins to pay down the stranded costs on their divested and retained generation assets. This approach produced devastating consequences for California, where the excess retail margins suddenly turned negative and caused the 2000–2001 California electricity crisis.[7] To avoid conflict between the goals of fostering retail competition and the recovery of stranded costs, these competition transition charges were generally applied as surcharges to the bills of distribution companies who maintained a monopoly franchise over the wires components of the business. Therefore, somewhat ironically, although the customer impetus that started electricity restructuring was a desire to avoid paying for

[6]In addition to generation assets operated by utilities, stranded assets in several states included uneconomic long-term contracts with IPPs that were mostly mandated by public utilities commissions under the Public Utility Regulatory Policies Act of 1978 (see White 1996).

[7]Through a combination of real scarcity and generator market power (caused in part by high local natural gas prices that followed a pipeline explosion), California's wholesale electricity prices skyrocketed in the summer of 2000 and remained extremely high into May of 2001. Under the competition transition plan, the two largest utilities in the state were not allowed to raise retail rates to reflect the high wholesale prices. One of them, Pacific Gas and Electric, was forced into bankruptcy and the other, Southern California Edison, nearly followed. For detailed discussions of these events, readers are referred to Joskow (2001), Blumstein et al. (2002), Borenstein (2002), Wolak (2003a), and Bushnell (2004).

high average costs during a period when marginal costs were lower, the transition charges largely guaranteed that utilities recovered something close to those costs anyway.

2.3. Restructuring and Reform of Retail Services

The aspect of restructuring to receive the most rhetorical attention and market hype was the relaxing of the utility monopoly franchise over retailing. Phrases evoking liberty and freedom, such as "customer choice" and "freedom to choose," were rhetorical staples of the restructuring process. There was also much hope that electricity retail competition might spur innovation in retail services in the way that it had for telecommunications. Exactly how this was supposed to be achieved was never clear.[8] Electricity service has proven to be less amenable to the sorts of usage and complementary product innovation that wired telecom service experienced in the 1980s and 1990s. Perhaps this is not surprising given that the product is so narrow—just the electricity, not any devices that use it—and so homogeneous. To use the grid, electricity must meet exact specifications that make one provider's product indistinguishable from another's. The place where innovation did seem valuable and likely to occur with retail choice was in financial arrangements: price schedules, payment plans, and options to bundle purchases with complementary products.

More concretely, retail restructuring involved giving customers access to new energy-only retail providers who produced or acquired wholesale power for sale to end users. The incumbent utility (and the grid operator) maintained a franchise over distribution and transmission-related functions. In many cases, the incumbent utility was allowed to continue to offer a default bundled retail rate for customers who did not switch retailers.[9] Customers who did switch received a bill for energy-only service from the third-party retailer they chose, and a separate charge, intended to recover transmission and distribution system investments made by the incumbent utility.

The extent to which this transformation materialized has varied greatly around the United States. **Figure 4** illustrates the fraction of total sales in each state from entities with an ownership classification of retail power marketer. Texas has far outstripped the rest of the country on the retail competition front, with the only other significant activity clustered in the Northeast.

To understand the potential for efficiency improvements in pricing electricity, it is useful to review the inefficiency concerns raised by the typical electricity retail tariff in the 1990s. Throughout most of the history of electric utilities, retail pricing policy has been driven more by equity than by efficiency considerations. Because customers had little alternative to the monopoly utility provider, and the utility was focused on satisfying the terms of cost-of-service regulation more than maximizing profits, there was little initiative to improve the efficiency of pricing. However, with greater competition and demand elasticity—from nonutility energy sources and retail suppliers, and more recently from improved opportunities to generate electricity on the customer side of the meter—the pressure to align prices with marginal costs has grown.

Efficient retail prices should reflect the short-run marginal cost in every hourly (or even shorter) time period at every location on the grid. At the beginning of restructuring, nearly all residential, commercial, and industrial customers faced prices that did not vary hour to hour. Furthermore, utilities recovered nearly all of their costs through volumetric charges, including the substantial share of costs that are fixed with respect to a customer's marginal consumption. For most

[8]Joskow (1997) discusses the potential for new product innovation under electricity restructuring.

[9]The bundled rate combined energy with the incumbent utility's transmission, distribution, and retailing charges. This was sometimes called the default provider or provider of last resort rate. In some states, the default provider franchisee is selected through auctions overseen by local regulators.

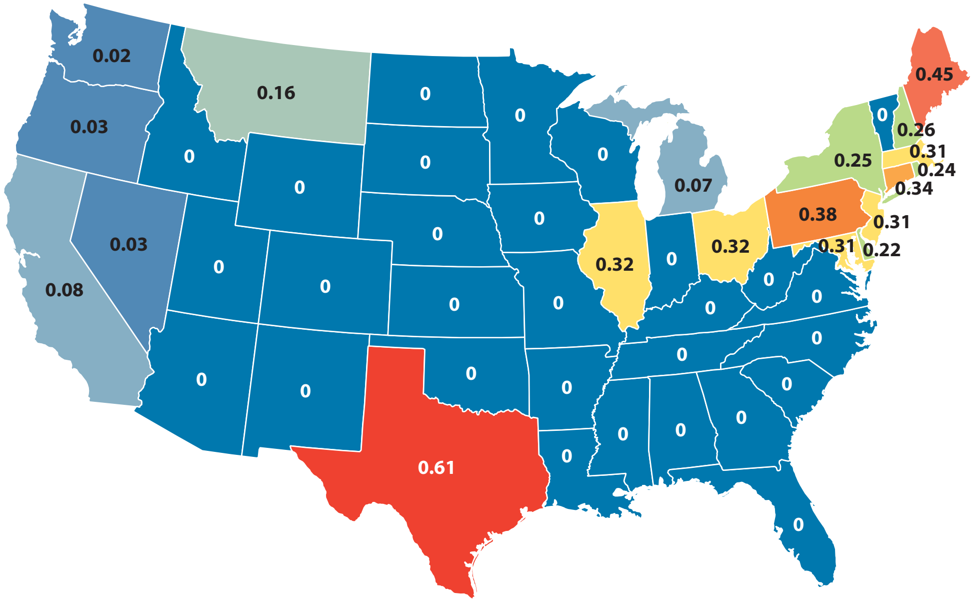

Figure 4

Share of retail sales from retail power marketers. Data are compiled from US Energy Information Administration (EIA) form 861.

residential customers, the rate was a simple constant price per kilowatt-hour (kWh) consumed, regardless of when the energy was used, set to cover all the utility's costs, variable and fixed.[10]

Setting price equal to short-run time-specific and location-specific marginal cost leads to efficient consumption given the level of investment, but only under a very narrow set of conditions does it exactly cover total costs.[11] In reality, there are almost certainly some costs that scale less than proportionally with the total quantity sold, so efficient marginal pricing would result in a revenue shortfall.

A fixed charge can be used to capture the additional needed revenue. A fixed charge (e.g., per month) is particularly efficient in residential electricity markets because the elasticity of connecting to the grid with respect to the monthly fixed charge is likely near zero over a wide range of charges. Thus, the deadweight loss that could result if some customers chose to consume zero because the fixed charge exceeds their consumer surplus is likely to be small.

For basically the same reason, however, the distributional consequences of a fixed charge are of great concern. Moving from a flat volumetric rate and no fixed charge to a lower flat rate and a fixed charge is very regressive. Borenstein (2011) shows that such a revenue-neutral change to a higher fixed charge and lower volumetric rate would raise the average bills of low-income customers by 69–92% of the fixed charge across the three large investor-owned utilities in California. Equity notions often suggest that the fairest allocation of such a revenue requirement would be in proportion to the quantity consumed (or, if data were available, in proportion to the

[10]Borenstein & Holland (2005) show that the break-even flat price could be higher or lower than the second-best optimal flat rate, depending on whether peak or off-peak price elasticities are higher.

[11]Under constant returns to scale, optimal pricing covers costs if the capacity is also set optimally. If the capacity is greater than the optimal level, optimal pricing will generate less revenue than is needed to cover the total costs.

consumer surplus gained by each customer). That approach, however, steers back toward average-cost pricing and the inefficiencies that it is known to produce.

The problem of average-cost pricing is exacerbated in the electricity industry by the nature of the contract between the retail provider and the customer. In nearly all cases, the customer has an option, but not an obligation, to purchase any quantity at the announced price, known in the industry as a requirements contract. This in itself would not be a destabilizing force if price adjusted quickly,[12] but with long lags between cost changes and price adjustment, this creates an opportunity for buyers to switch between alternative suppliers inefficiently. This is the same phenomenon as described above for the state decision to deregulate but manifest in contemporaneous customer choice among competing sources. The combination of requirements contracts and average-cost retail pricing could create increasing problems if DG (behind the meter) continues to expand, as we discuss below.

Thus, as restructuring began 20 years ago, retail pricing deviated considerably from the ideal efficient structure. It seemed at least possible that competitive pressure on the existing structure would lead to substantial changes in pricing, and the potential for differentiation among the products retailers sold. The technological and market configuration, however, turned out to leave much less space for pricing innovation than was suggested at the time.

The principal technological constraint was metering: In the 1990s, virtually all residential customers, and most commercial and industrial customers, had meters that recorded only the aggregate amount of electricity that had flowed through them. They did not have the capability to collect information on when the electricity was consumed. This meant that time-varying pricing was not feasible without a significant investment in metering. Nor could a retailer necessarily overcome this constraint just by metering its own customers because the arrangements for billing and payments among retailers and the utility providing distribution services were generally not set up to accommodate time-varying pricing. Instead, in most cases, a retailer was deemed responsible for providing power to its customers—either generating it, signing long-term contracts, or buying on the spot market—based on a standard assumed load shape (a time-varying pattern of consumption) that was applied to all customers within broad location, customer type, and sometimes size classes. The assumed load shape was independent of the prices the customer faced, so the retailer had no incentive to charge time-varying prices. With the expansion of smart meters in the late 2000s, the groundwork is now being laid for broader use of time-varying pricing, but the vast majority of residential customers with nonutility retail providers still see no time variation in the prices they pay. Commercial and industrial customers have experienced a much greater shift toward time-of-use pricing, which entails two or three different preset prices that apply at different times of the week. Time-of-use pricing, however, is known to capture a small share of the hourly variation in wholesale electricity prices (see Borenstein 2005).

A second way in which retailers might have offered greater differentiation was in reliability, but this too was undermined by the structure of the retail markets that were established. Because they must always balance supply and demand to avoid service disruptions, the grid operators in these markets procured enough reserves to make sure that the full expected demand could be met. If one retailer did not procure sufficient supplies to meet its retail demand obligation, the result was not reduced supply to the customers of that retailer—as would occur with nearly any other product. Instead, the grid operator drew on its reserves to make sure all demand was met. The cost of those reserves was spread over all retail quantities whether or not the provider to a particular customer

[12]In a sense, sellers in any commodity market operate under requirements contracts, at least over a large range of purchase quantity, but they can and do change prices rapidly as market conditions change.

ever caused the grid operator to need those reserves. Reliability was assured by the grid operator and charged to every kilowatt-hour supplied, so there could be no differentiation on reliability. Alternative arrangements—in which either the customer lost power when its supplier had procured insufficient quantities (which posed technological challenges along the same lines as real-time metering) or the retailer or customer was charged a very high fee for running short of delivered electricity—would have created a significant cost for insufficient supply and likely led to greater product differentiation along these lines, but these were not widely adopted. The lack of retailer responsibility for reliability also undermines the incentive to implement price-responsive demand, which could be a valuable tool for a retailer in balancing its supply and demand while keeping costs down.

Reliability differentiation also could extend to the ramifications of exit by the retailer. If a retailer exits the market, what cost is borne by its customers? If customers can easily switch to another supplier at a predetermined rate, then a similar moral hazard problem arises in which a retailer can procure short-term power at spot prices when that price is low but exit if the spot price rises, leaving the customer to switch to some default rate. If that default rate is a price that reflects average procurement costs over a longer period, then once again the variation in average versus marginal price drives behavior in the market. Enron and some other retail providers in California took this path when prices in the California wholesale market spiked in 2000. In Texas, which has the most extensive retail residential competition (see **Figure 4**), rules have been adjusted so that customers of a retail provider that exits are moved, by default, to a tariff that reflects the contemporaneous marginal cost of procuring power.

3. ELECTRICITY MARKET PERFORMANCE SINCE RESTRUCTURING BEGAN

The most consequential economic changes of electricity restructuring took place in the wholesale production and marketing sectors of the industry. We therefore begin this section by discussing the evolution of the industry since 1997 at the wholesale level. As discussed above, formal centralized markets formed only in the parts of the country that embraced the RTO/ISO structure, which were also the areas with the highest prices and for which the average cost exceeded the marginal cost by the largest amount.

3.1. Wholesale Markets

The regions with RTO/ISOs are also the markets for which the best data on wholesale prices are available. **Figure 5** summarizes annual average prices from two data sources. For 1998 through 2000, we use data from Bushnell et al. (2008), which are drawn from ISO websites. For 2001 on, we report data from the Intercontinental Exchange (ICE) for trading hubs in Southern California (SP15), western Pennsylvania (PJM), Massachusetts (ISO-NE), and the Pacific Northwest (Mid-C) hubs.

Since 1998, two facts are worth noting. First, although somewhat muted by the annual aggregation in the data, the California market stands out as suffering from sustained, extremely high price levels during the 2000–2001 period. Both academic research and subsequent regulatory findings have determined that this market suffered from a lack of competition made acute by a combination of tightening capacity and a near total absence of forward contracting (see Borenstein 2002, Borenstein et al. 2002, Joskow & Kahn 2002, Wolak 2003b, Bushnell 2004, Puller 2007, Mansur 2007, Bushnell et al. 2008). Second, in the other markets, wholesale power market prices are dominated by natural gas prices, although somewhat less so in the Pacific Northwest. This is consistent with the general fact that natural gas–fired generation units are the marginal

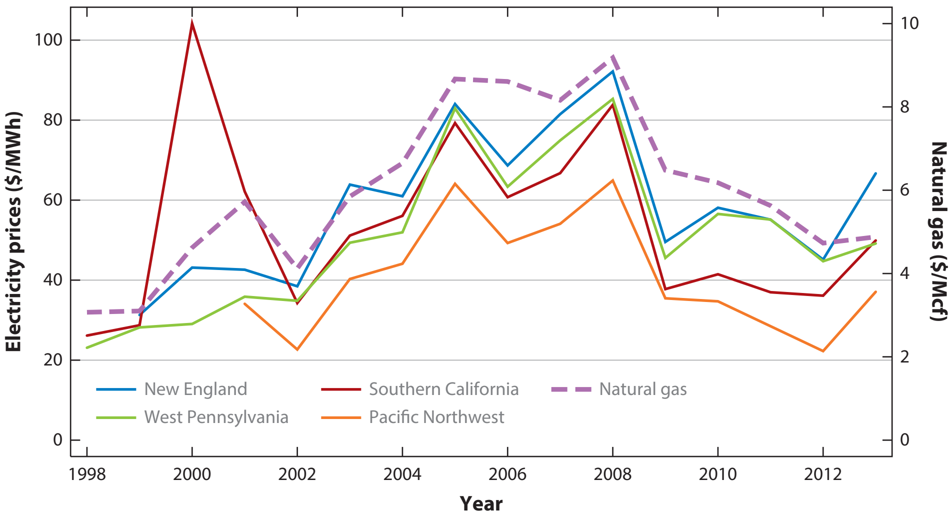

Figure 5

Wholesale electricity and citygate natural gas prices. The dashed line summarizes the US average citygate natural gas price, taken from the Energy Information Administration. The years 1998–2000 represent independent system operator hourly average prices, whereas 2001–2013 represent Intercontinental Exchange peak power contracts. Data are from Bushnell et al. (2008) for 1998–2000 and from the Intercontinental Exchange for 2001–2013.

source of power in most markets during most times, but the Pacific Northwest is influenced more by the availability of hydroelectric power.

Because gas generation composes a minority share in most electricity markets, under average-cost-based regulation it did not dominate rate making. Prices for deregulated generation, however, are driven by the marginal producer, which is much more commonly gas generation. Thus, to a degree that was not appreciated at the time, restructuring of generation greatly increased the exposure of electricity rates to natural gas costs, even if a fairly small share of electricity was sourced from natural gas–fired plants. As natural gas prices nearly tripled during the first half of the 2000s, the impacts on retail rates and the rents created for inframarginal generation were far greater than they would have been under regulation.

During 2006 and 2008, the US natural gas price peaked above $11 per MMBTU. The higher gas prices drove up generation costs and power market prices. By this time, the relationship between marginal and average costs of power production had again reversed so that marginal cost–based market prices were higher than the average costs of operating and producing from a mixed-generation portfolio. Many of the nuclear and coal-fired power plants in restructured states, which had been considered stranded assets in the late 1990s, were by 2007 tremendously profitable because of their low operating costs and the relatively high market prices they earned for their output.

The combination of higher prices and healthy profits earned by power producers in restructured states contributed to a strong dissatisfaction with restructuring in several states (see Johnston 2007). This mood of ex post regret in restructured states peaked in 2007–2008. States such as Illinois, Maryland, and Maine initiated proceedings that were characterized as rolling back deregulation (see Sharp 2007, Behr 2009). After 2009, however, with plummeting natural gas prices and increasing reserve margins, momentum for significant changes dissipated.

3.2. Restructuring and Plant Operations

One aspect of restructuring that has been studied at a micro level has been its impact on the performance and efficiency of power plants. Overall, the results point to a positive influence of restructuring on the operations of plants. Unfortunately, although cost data on regulated plants are extensive, there are much fewer data available on the costs of nonutility generation. Thus, studies of plant-level impacts of restructuring either have focused on its impact on regulated plants or were limited to a focus on the few performance variables that continue to be reported for deregulated plants. Fabrizio et al. (2007) compare the performance of regulated plants in states that pursued restructuring [by the US Energy Information Administration's (EIA's) definition, which we discuss further below] against regulated plants in states that did not initiate restructuring, and against publicly owned plants in both types of states. They find modest efficiency gains in the restructured states, much of these focused on employment and labor productivity. There is some evidence that the efficiency of fuel consumption, the largest single variable expense in power plants, can be influenced by incentives and skill (see Bushnell & Wolfram 2009), but to date the evidence on fuel efficiency at restructured plants has been inconclusive.

The most dramatic documented impact of restructuring on power plant operations has been on the performance of nuclear plants, as shown by Davis & Wolfram (2012). Almost half of the nuclear generation plants in the United States were divested to nonutility producers since 1998.[13] Davis & Wolfram show that industry-wide US nuclear power plants have greatly increased capacity factors since 1998, but relative to their regulated counterparts, output at the restructured plants increased 10% between 1998 and 2010. They estimate that this additional output has a market value of $2.5 billion annually.[14]

3.3. Restructuring and Retail Prices

It is useful to begin a review of retail prices under deregulation by examining conditions in 2007, when dissatisfaction with restructuring peaked. In 2007, the *New York Times* ran a series of articles highlighting that rates had risen faster in restructured states than in regulated ones (see Johnston 2007). The articles cited studies that relied on average retail price data reported to the EIA and essentially performed a difference-in-differences comparison between restructured and nonrestructured states (see Showalter 2007, Tierney 2007).

A central challenge in studies such as these is to identify what constitutes a restructured state in order to assign a state to one category or the other. Many papers have relied on the EIA's definition, which is focused on the status of retail competition. An alternative measure of a restructured state is based on the fraction of energy generated that is produced by IPPs. **Figure 2** illustrates these values for 2012, but we can apply the full panel of values to capture the underlying points of transition in each state.

As one examines recent data on retail rates, it is clear that many of the conditions of 2007 have since dramatically reversed. **Table 1** summarizes the average retail rates in states considered restructured, according to two alternative measures, against those that remained under traditional regulation.[15] The

[13]Since 1998, no new nuclear plants have come online in the United States, although a few are scheduled to be completed in the next few years.

[14]Hausman (2014) concludes that the gains in utilization were not accompanied by the degradation of safety among deregulated plants.

[15]We examine the average rate across all major rate categories, including residential, industrial, and commercial. Several previous studies, including Showalter (2007) and Apt (2005), have focused on rates paid by industrial customers.

Table 1 Summary of retail price changes

Definition of restructured	Status	Average retail price (USD)			Percent change		
		1997	2007	2012	1997–2007	2007–2012	1998–2012
Power in the Public Interest definition	Not restructured	5.89	7.44	8.72	0.21	0.15	0.32
	Restructured	8.96	12.53	12.35	0.29	−0.01	0.27
At least 40% independent power producers in 2012	Not restructured	5.67	7.23	8.57	0.22	0.16	0.34
	Restructured	8.83	11.99	11.95	0.26	0.00	0.26

Retail price data are from US Energy Information Administration (EIA) form 861, which reports sales and revenues by utility.

first measure is the one used in a study by Showalter (2007) for Power in the Public Interest that is cited in the *New York Times* article (Johnston 2007). This definition excludes from the restructured category states such as Illinois and Pennsylvania, which by 2012 have almost all of their energy provided from nonutility sources. As an alternative measure, we assign states to the restructured category if they had more than 40% of their energy provided by nonutility sources in 2012.[16]

From **Table 1**, one can see that at this level of analysis, the definition of restructured makes only a small difference. The time period examined, however, makes an enormous difference as rates in restructured states increased at a pace nearly 50% higher than those in nonrestructured states between 1997 and 2007 but have actually declined slightly since 2007. Average rates in states that did not restructure have continued to increase since 2007, although at a slightly lower pace than between 1998 and 2007. Overall, there is almost no difference in the change in average rates for the two groups over the full sample from 1998 to 2012.

Figure 6 illustrates the annual levels of rates in restructured and nonrestructured states using our generation-based definition, along with the national average citygate natural gas price. Restructured states experienced higher rates during the 1990s, a major factor in their election to adopt restructuring. The gap between traditionally regulated and restructured states narrows around 1998, reflecting the impact of legislation that required immediate rate reductions to accompany restructuring in several states. Since that time, rates in restructured states more closely follow the trajectory of gas prices up during the early 2000s and back down since then.

To further test this relationship among natural gas prices, restructuring, and electricity rates, we estimate the following regression on state-level annual changes in electricity prices and citygate natural gas prices:

$$\Delta \mathrm{Elec}_{s,t} = \alpha + \beta_1 \mathrm{FractionIPP}_{s,t} + \beta_2 \Delta \mathrm{NGas}_{s,t} + \beta_3 \mathrm{FractionIPP}_{s,t} \times \Delta \mathrm{NGas}_{s,t}, \tag{1}$$

where $\Delta \mathrm{Elec}_{s,t} = \ln(\mathrm{Rate}_{s,t}) - \ln(\mathrm{Rate}_{s,t-1})$ and $\Delta \mathrm{NGas}_{s,t} = \ln(\mathrm{NGas\_Citygate}_{s,t}) - \ln(\mathrm{NGas\_Citygate}_{s,t-1})$ are the annual changes in log state average electricity rates and log state average

[16]The *New York Times* article lists the restructured states as California, Connecticut, Delaware, Maine, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Rhode Island, and Texas and the District of Columbia (Johnston 2007). Our generation-based definition puts California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, New Hampshire, New Jersey, New York, Ohio, and Pennsylvania into the restructured category.

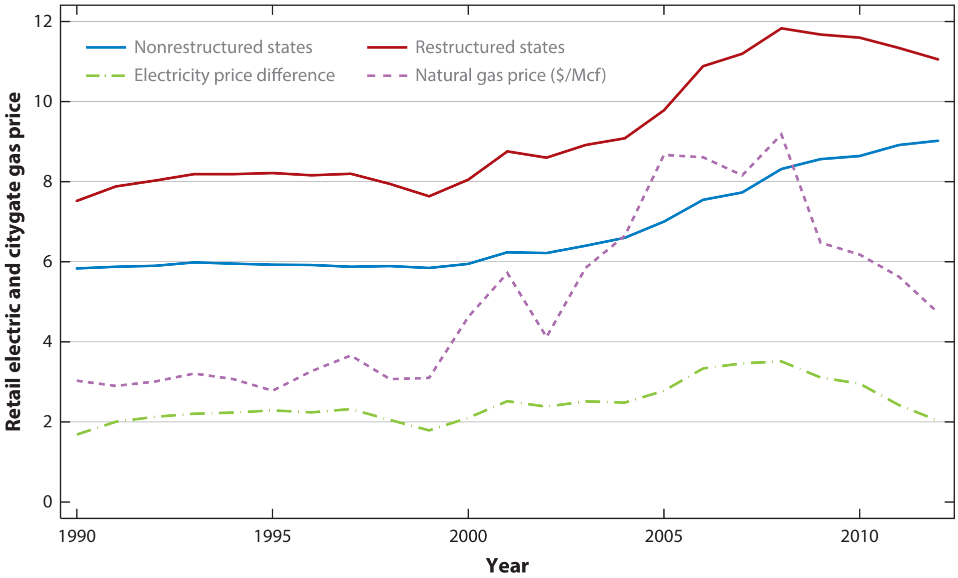

Figure 6

US average retail rates and natural gas prices.

citygate natural gas prices, respectively. We estimate for 1998 (the change from 1997) to 2012. **Table 2** presents the summary statistics for these variables in the years 1997 and 2012. We estimate Equation 1 clustering standard errors at the state level.

The results of the regression in Equation 1 are reported in **Table 3**. As **Table 1** suggests, restructuring, which we are representing with the fraction of energy generation from nonutility sources in that year (FractionIPP), has no statistically discernible effect on average changes in rates over the 1997–2012 period. The point estimate implies that a state with 100% merchant generation has a 0.6% higher average annual rate increase, but one cannot reject no effect at conventional significance levels. Changes in local natural gas prices, however, do influence rates. The second column of **Table 3** suggests that a 1% increase in natural gas prices implies a 5% increase in electricity prices on its own. The third column in the table yields greater clarity on the mechanism. When the change in natural gas price is interacted with FractionIPP, the results suggest that the effect of natural gas is much greater in restructured states, as the earlier discussion would suggest. The influence of natural gas prices on retail rates is estimated to be nearly twice as large in a state with all merchant generation than in a state with none. The effect of natural gas prices in a state with no merchant generation is not statistically significant, whereas the interacted effect with FractionIPP is highly significant.

We do not intend this to be an exhaustive analysis of the drivers of retail prices.[17] However, these data are strongly supportive of the argument that, apart from the California electricity crisis, any harm that electricity restructuring has done to consumers was a side effect of changes in the price of natural gas. In restructured markets, natural gas generation determines market prices and therefore

[17]Others, such as Apt (2005) and Taber et al. (2006), have performed more extensive exercises, but only utilizing data during the early years of restructuring.

Table 2 Summary statistics of retail electric and natural gas prices

Variable	Mean	Standard deviation	Minimum	Maximum
Data for 1997				
Price	6.72	2.03	3.87	11.66
Fraction IPPs	0.03	0.07	0.00	0.46
Natural gas	3.54	0.64	2.12	5.18
Data for 2012				
Price	9.70	2.30	6.90	15.54
Fraction IPPs	0.35	0.33	0.00	0.99
Natural gas	4.90	0.97	3.46	7.73

Both time series are from the US Energy Information Administration (EIA). Electricity rates are the total electric industry average price across all customer classes, per state, as reported at **http://www.eia.gov/electricity/data/state/** and are derived from EIA form 861 data. Natural gas prices are available at **http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm** and are derived from EIA form 857 data. Abbreviation: IPP, independent power producer.

the remuneration for all the nonutility assets. The more nonutility assets featured in a state's generation mix, the more exposed that state is to the natural gas market.

Simply put, restructuring in the United States was in hindsight very poorly timed. Assets that were viewed as stranded in 1998 were sold as white elephants at prices far below what they would have fetched in 2007. Conversely, large customers in the 1990s were motivated by low wholesale prices to push for restructuring, but the switch to market pricing, which increased their exposure to the natural gas market, came just as natural gas price increases were starting a long climb up to a peak in 2007. This timing is not coincidental: The same factors that contributed to the low valuation of utility assets in the late 1990s (low wholesale prices) were the ones that made the prospect of restructuring so appealing to customers and policy makers.

3.4. The Evolution of Retail Price Structures

Unfortunately, data on retail price structures are much less available than are data on average retail price levels. Nonetheless, it is clear that there has been gradual movement toward time-varying pricing, primarily for commercial and industrial customers. In the last decade—partially in response to funding from the 2009 American Recovery and Reinvestment Act—many utilities have rolled out so-called smart meters, even to residential customers. Estimates vary, but by 2013, more than 40% of all customers in the United States likely had smart meters (see FERC 2013).

These meters record total electricity consumption in hourly or shorter periods and can facilitate much wider use of pricing that changes frequently to reflect real-time supply/demand balance, known as dynamic pricing.[18] So far, such granular and timely pricing has appeared for only a narrow slice of large industrial and commercial customers, but with smart meters now in place, most of the financial cost of dynamic pricing, down to even residential customers, has been sunk.

[18]The meters also communicate information to the utility without an onsite visit by a meter reader. Savings on meter reading labor have been the largest benefits projected by the installation of smart meters.

Table 3 Analysis of retail price changes

	1	2	3
Percentage IPPs	0.006 (0.005)	0.007 (0.005)	0.006 (0.005)
Percent change in natural gas		0.051 (0.016)	0.023 (0.016)
Percent change in natural gas × percentage IPPs			0.018 (0.005)
N	720	720	720

The dependent variable is change in log annual state-level average electricity rates. Standard errors (in parentheses) are clustered by state. Abbreviation: IPP, independent power producer.

Still, there remains substantial resistance to dynamic pricing among residential consumers and groups that represent them. Data from a 2012 EIA survey of utilities suggest that only a few percent of customers are on tariffs that have any dynamic pricing component (see FERC 2013 and data from EIA form 861).

Of course, the efficiency gain from dynamic pricing depends on the ability and willingness of customers to respond to those prices. Opponents have generally argued that households will not pay the attention necessary to adjust thermostat settings, washer/dryer use, and other electricity-consuming activities in response to dynamic prices. Simple calculations, such as in Borenstein (2013), show that the financial gain from paying attention to such price fluctuations has been modest. Still, increased penetration of intermittent generation resources (wind and solar) is likely to increase wholesale price volatility and raise the social return to such attention, while automation is likely to continue lowering the cost of the necessary attention.

A very large literature has now developed using randomized control trials, randomized encouragement designs, and quasi-experiments to analyze just how much consumers do respond to dynamic pricing. The evidence is fairly consistent that even without automation, customers respond significantly on average, although with a fairly small elasticity, generally estimated to be in the range of −0.1 to −0.2 (see Ida et al. 2014, Jessoe & Rapson 2014, Wolak 2011a). The research suggests that the larger elasticities result from interventions that include technology to convey information, such as emails, text messages, and in-home electricity usage displays.

The literature on elasticity with automated demand response is much thinner; it is pretty much nonexistent in economics outlets. But programmable controllable thermostats—which can permit a person to automate response to a price or other warning signal or allow an authorized third party to do so—have been in use for more than a decade. Industry publications suggest that these technologies greatly increase potential demand response (see Faruqui & George 2002).

4. THE NEXT 20 YEARS

After a tumultuous period from 1996 to 2005, the regulatory/legal status of electricity restructuring—in generation, transmission, distribution, and retailing—has changed little in the past decade. In recent years, however, the continuing evolution in technology and in environmental concerns has disrupted the industry in new ways. These changes are ongoing and are likely to continue for many years.

The greatest change occurring in electricity markets today, and likely going forward for many years, is the increased recognition of the environmental costs of electricity generation, most notably (but not exclusively) greenhouse gas (GHG) emissions. Environmental issues have played a significant role in electricity for decades, but most of the emphasis in past years was on limiting the local air and water pollution from traditional generation sources. Of course, appropriate pricing of the environmental externalities, either through a tax or a cap-and-trade program, would be the simplest and most efficient way to incorporate these environmental costs.[19] Currently, most US utilities pay zero for their GHG emissions, while a minority pay prices well below the most common estimates of the social cost of those emissions. In that situation, raising the marginal retail price above the utility's private marginal cost can be efficient, of course, and it can at the same time reduce the need for fixed charges discussed above.

In the past decade, with growing concern about climate change and with improving technology, environmental stakeholders have turned more and more to goals for increasing generation from renewable sources. Even though hydroelectric and nuclear generation are by far the largest low-carbon sources in the United States, wind and solar power are growing rapidly, as shown in **Figure 7**.

The growth of wind and solar generation sources raises two issues that are now coming to dominate policy discussions among utilities and policy makers: (*a*) the economic and technical management of intermittent-production resources for which costs are largely sunk before production begins and (*b*) policy toward DG resources that are on the property of the end user (so-called behind-the-meter generation). The latter is primarily an issue with rooftop solar photovoltaic (PV) systems today but could expand to batteries and other generation or storage devices in the future.

4.1. Management of Intermittent Generation Resources

Numerous regulatory and legislative initiatives, including President Obama's Clean Power Plan proposed in 2014, are pressuring electricity providers to reduce the GHG footprint of the power they supply. Many options exist for reducing GHG emissions from electricity, but among the most prevalent today is the greater use of wind and solar power. Economic and technical integration of these intermittent renewable generation resources is likely to be one of the principal challenges facing the electricity industry in the next few decades.

The technical challenge stems primarily from the fact that production from these resources occurs intermittently and largely outside the control of the owner—when the wind blows or the sun shines.[20] Because the physics requires that quantities supplied and demanded in an electrical grid must balance at all times for the system to be stable, and because storage is still quite expensive, the intermittency of wind and solar power implies that either other flexible supply resources must be available to offset these fluctuations or demand must change in response. Both solutions are technically feasible, although supply side responses have been the focus of more discussion.

[19]"Appropriate" is a key word here. Simply setting a tax or a quantity cap addresses the issue efficiently only if the tax or quantity limit is set correctly. This is an obvious point, but one that seems to be missed or ignored by many policy makers.

[20]In reality, these resources can be adjusted downward, just not upward if wind or sun is not present. Both wind and solar PV systems are potentially curtailable but require communication between the grid operator and the resource. Wind turbine blades can be positioned so as not to catch the wind and stop turning. Solar PV system curtailment requires a smart inverter that can be told to disconnect the PV system from the grid. The inverters currently on nearly all residential and small commercial systems do not have this capability.

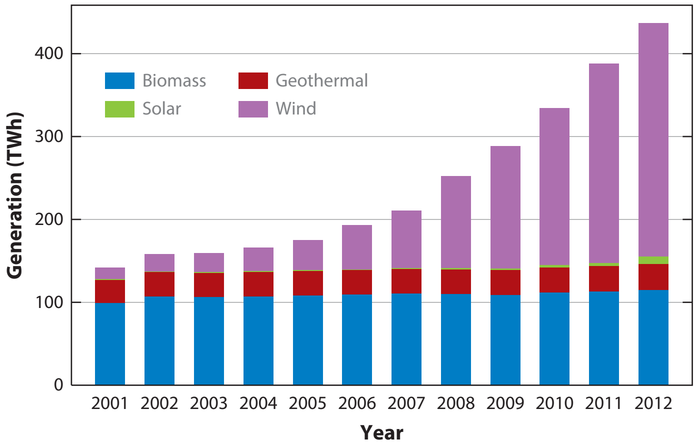

Figure 7

Electricity produced from non–hydro renewable sources, excluding distributed generation.

Intermittency problems occur on both short and long timescales. Large fluctuations in electrical generation can occur second by second from solar PV systems, and minute by minute from wind. On a longer scale, both wind and solar power can exhibit many hours of higher or lower production than was forecast even a day in advance (see Joskow 2011, Schmalensee 2012). Short-scale intermittency is generally localized and idiosyncratic, so a diversity of locations may substantially mitigate the problem, although studies suggest that some additional balancing resources or demand responsiveness will still be necessary at high penetration (see Mills & Wiser 2010, Tabone & Callaway 2013).

Longer-scale intermittency is likely to be a more formidable problem if wind and solar power become a large share of generation capacity. Absent inexpensive electricity storage, days or weeks without much sunshine or wind would create energy supply fluctuations that would be very costly for demand to follow. If the existence of those days requires full or nearly full capacity coverage from conventional fossil resources, then the full cost of supplying power with high–renewable resource penetration grows significantly.

Further complicating the technical challenge, conventional fossil generation is constrained in how quickly it can ramp output up and down to offset large changes in output from renewable resources. In general, the most flexible conventional generation is from gas-fired peaker plants, which are also the least efficient and most expensive. Larger combined-cycle gas turbine plants are somewhat less flexible, but of lower cost, and coal and nuclear plants are the least flexible.

A well-known concern is illustrated in what has become known as the duck chart shown in **Figure 8**. The duck chart presents the forecast total demand and net demand for the California electricity grid on a sunny spring day with high penetration of solar PV systems.[21] The lowest line shows the net demand after subtracting solar PV generation from total electricity consumption with solar penetration projected for 2020. Even if solar generation were perfectly forecastable, the rapid drop in net demand as the sun rises and increase in net demand as the sun sets would be difficult to meet with the current mix of gas-fired generation in California.

[21]This could be seen as a worst case, because a sunny spring day with relatively cool temperatures maximizes afternoon solar PV production while minimizing demand from air conditioning.

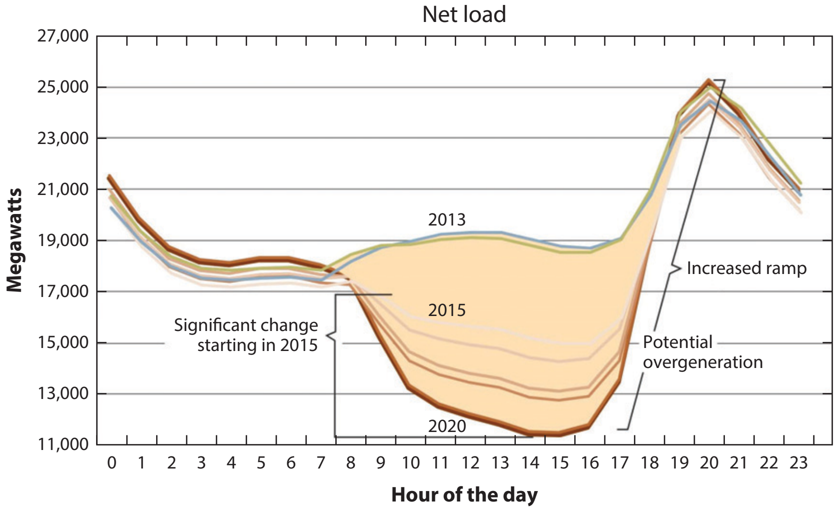

Figure 8

Projected hourly California demand and solar production (on a sunny, cool March weekday) with increased solar penetration.

The most cost-effective solution proposed by a recent study would be to run more gas-fired plants in the middle of the day and curtail production from solar PV systems (see Energy Environ. Econ. 2014). In other words, the least costly engineering solution at this point may be to forego electricity that has zero marginal cost. It seems quite possible that if retail prices at these times were set at or near zero to reflect this situation, consumers would find innovative ways to use nearly costless electricity, but that requires the adoption of high-frequency, time-varying pricing. Although such pricing is completely feasible with current smart-meter technology, it has not been widely adopted, as mentioned above. In this way, technical challenges to integration overlap a great deal with economic policies.

Further economic challenges arise with the addition of subsidized renewable resources because they change the economic returns to conventional generation. The most notable change is that, because they have near-zero marginal cost, solar and wind generation are generally used virtually all the time they are available. This pushes out the supply curve and lowers the market clearing price for electricity, reducing profits for all conventional generation in the market. In the longer run, this worsens the economics of conventional generation and can lead to exit. All of that would be a description of an efficiently operating competitive market if no generation sources were subsidized, all sources paid their full social marginal cost, and electricity prices reflected the social value of marginal production at every point in time. However, renewable generation costs are artificially low owing to investment and production subsidies, while conventional generation does not pay for its negative pollution externalities. Additionally, wholesale prices do not reflect the value of marginal power at a specific point in time or space; instead, the system operator separately arranges for electricity needed to maintain voltage in specific areas, to offset the fluctuation of intermittent resources and for other operational constraints, and to respond to unforecasted demand volatility. One of the common ways to assure that needed capacity does not exit is through capacity payments, which generally pay companies to have generation available regardless of the electricity they are called upon to generate (see Joskow 2008 for a broad overview of the role of capacity payments).

4.2. Policy Toward Distributed Generation

Cost reductions in solar PV technologies have also changed the economics of self-generation by end-use customers, known as DG. In California, Hawaii, and other sunny locations with high electricity prices, falling PV system costs have combined with substantial federal and state subsidies to make installing solar PV systems a money saver for some customers. The result has been a booming market in behind-the-meter solar PV systems. In the United States, distributed solar PV capacity installation has increased from 400 MW in 2009 to approximately 1,900 MW in 2013, with about half of new installations occurring in California (see Sherwood 2014).[22]

This trend has led some observers and utility executives to predict a death spiral in which a significant number of customers self-generate much of their electricity, forcing the utility to raise rates for the electricity they still sell in order to cover fixed investments, in turn making solar PV systems economic for a larger set of customers who then reduce their purchases, leading to a greater revenue shortfall and another rate increase, and restarting the cycle. Ultimately, some argue, the monopoly utility disappears. This scenario has triggered widespread debate, both positive and normative, about the future and viability of the utility. The regulator in New York State has even proposed a complete redesign of utility systems that is focused on customers also being generators (see NYS Dep. Public Serv. 2014).

The social welfare gain from increasing reliance on distributed PV generation, however, is still far from clear. Even the most optimistic cost scenarios suggest that the full social levelized cost of electricity from residential solar PV systems is likely at least $0.20 per kWh in relatively sunny areas, more than double the full cost of gas-fired generation including a GHG cost of $40 per ton.[23] Distributed PV generation is eligible for the same tax benefits as large-scale solar generation, a 30% tax credit through the end of 2016 and accelerated depreciation. Borenstein (2015) estimates that the accelerated depreciation amounts to an additional effective subsidy of approximately 15%.[24]

Distributed PV generation also benefits from being compensated at retail prices for the power it produces. Under net metering, which has been adopted in most of the United States, customers are credited for all power produced from their PV systems by deducting the quantity from the customer's consumption (see **http://www.dsireusa.org/resources/detailed-summary-maps/** for timely information on US state net metering policies). In reality, calculations by Darghouth et al. (2013) suggest that less than half of the power produced by a typical household PV system is consumed onsite—actually reducing the customer's retail demand—but net metering treats all power as demand reduction, thereby crediting it at the retail rate the customer would have paid.[25] If the full benefits that DG solar PV power brings to the market are less than the marginal rate the customer pays, then net metering policies lead to the overcompensation of DG solar production. A

[22]These numbers are the sum of residential and nonresidential installations that are nonutility scale.

[23]The $0.20 per kWh figure uses the calculations in Borenstein (2012) and recent system-cost figures reported by Barbose et al. (2014) to be as low as $4 per watt of installed capacity. Most estimates of the long-run private cost of gas-fired generation are around $0.06 per kWh and emissions of about 0.0004 tons of GHG per kWh. Valuing the social cost of GHG emissions at $40 per ton yields a full social cost of $0.076 per kWh.

[24]Actually, the accelerated depreciation benefit is available only if the system is owned by a company, not an individual. This has been a significant factor behind the rapid growth of third-party-owned residential systems in which the third-party owner leases the system to the homeowner or, more commonly, sells the electricity from the system to the homeowner. Third-party owners of these systems point out that this model also greatly lowers, or eliminates, the up-front payment the homeowner would otherwise have to make.

[25]This is for a system that generates electricity equal to the household's annual electricity demand. The figure is higher if the system is smaller relative to the household's consumption.

simple calculation suggests that this is very much the case, but the full system benefits are a matter of some dispute (see Borenstein 2012, Cohen & Callaway 2013). What is clear is that retail electricity rates are set in ways that are not closely tied to long-run marginal cost, so incentivizing DG solar systems through net metering will conflate solar policy with rate design policy and will have unpredictable effects on the incentive to install residential solar systems.

Probably the clearest illustration of perverse incentives from net metering policy is in California, where more than half of US residential PV systems have been installed and where the gap between marginal retail rates and marginal cost may be the highest. Most California utilities use increasing-block residential electricity pricing, meaning that the marginal price a customer faces increases in steps as the customer's consumption increases during the billing period. The two largest California utilities, each of which has an average residential retail price of approximately \$0.18 per kWh, have four blocks in their residential tariffs with prices from approximately \$0.12 per kWh up to more than \$0.35 per kWh on the highest block. Borenstein (2015) reports that a greatly disproportionate share of California households installing PV from 2007 to 2013 had consumption levels that reached into the two highest-price tiers. He also finds that installations have been calibrated to eliminate consumption on the highest-price tiers, but not to crowd out the lower-price consumption. Borenstein (2015) estimates that the average bill savings from installing a DG solar system for customers of these utilities was 25–50% greater owing to increasing-block pricing than it would have been if the utility charged a flat rate equal to their average residential price per kilowatt-hour. He estimates that the bill savings were more than double what they would have been if the utilities had charged \$0.10 per kWh, a rough approximation of social marginal avoided cost.[26]

Talk of a death spiral and concerns of the viability of utilities, however, raise a question that extends far beyond these issues of implicit and explicit subsidies and the value of incremental DG solar power. Can DG really function without the grid? Without low-cost electricity storage, and tolerance of less reliable electricity at some times (e.g., a week without sunshine), it seems unlikely that most customers will be ready to operate off the grid anytime soon. If the grid is needed, how should it be paid for? The utility pricing model to date has been based on volumetric average-cost pricing. DG at this point looks very much like the push for restructuring discussed in Section 2: a comparison of the average cost to marginal cost that ignores that the difference is not a real savings, but rather cost shifting. To the extent that a DG solar household has costs greater than or equal to the social marginal cost of grid-supplied electricity, the private savings are offset, or more than offset, by a revenue shortfall at the utility. That shortfall must then be made up by utility shareholders or, more likely, remaining rate payers. In fact, the notion of a death spiral, with rising retail rates as consumption declines, necessarily implies that price is above marginal cost and that there is an excessive incentive to install DG systems.

[26]The best estimate of long-run marginal cost from gas-fired generation is approximately \$0.06 per kWh as mentioned above, but DG solar PV power consumed onsite also avoids the 7–9% of electricity that is dissipated through line losses as the power flows from generation through transmission and distribution lines to the end user (see Borenstein 2008). Accounting for line losses, the electricity delivered for consumption from conventional generation has a marginal cost closer to \$0.065 per kWh. The timing of power from solar PV also boosts its value or the cost of alternative sources. Solar PV generation produces more at peak times, so it is replacing power at times when marginal electricity costs are higher. Borenstein (2008) estimates that in real-world grid operation, this increases the cost of the alternative power source by an average of 20%, bringing the marginal cost of alternative generation to approximately \$0.078 per kWh. Inclusion of the cost of GHG emissions raises the cost of alternative generation by \$0.015–0.02 per kWh at a GHG price of \$40 per ton, bringing the alternative marginal cost to approximately \$0.10.

5. SUMMARY

The changes in the electricity industry over the past two decades have been dramatic, but many were not the changes anticipated at the beginning of the industry's grand experiment with market-based pricing of generation and retail services. Although the revenues for much of the nation's conventional and nuclear generation sources are now based on market prices rather than production costs, retail pricing for the vast majority of residential customers remains dominated by state regulatory processes.

In the mid-1990s, the strong momentum for restructuring was driven by a large gap between market-based prices, which were based on marginal cost in competitive markets, and regulated rates, which were based on average production costs. During this period of relatively large capacity margins and low natural gas prices, market-based pricing appealed to customers and terrified utility shareholders whose assets would become stranded, absent other compensation. However, despite the allure of market-based pricing, the reality of the regulatory process, and of case law, dictated that utilities be allowed to recover the bulk of what appeared at the time to be stranded costs.

The great irony of this period is that a half decade after transition arrangements largely compensated utilities for the losses incurred in selling or transferring these assets, the market value of those same assets had fully recovered. By the mid-2000s, the relationship between average and marginal costs had largely reversed, and many states expressed a great deal of regret about the decision to restructure. However, because the formerly regulated generation assets were now largely held by private, deregulated firms, there was no clear path to dramatically re-regulate the industry without paying full market value for those assets. Looked at this way, one can view the disappointment with restructuring as being driven by magnificently poor market timing. Utilities sold off their assets at the nadir of their value; then, as natural gas prices climbed throughout the 2000s, those assets became quite valuable under market-based pricing.

Since 2009, this story has largely reversed yet again. Natural gas prices have declined sharply, nearly to the levels seen at the dawn of the restructuring movement. The attention of policy makers has now been consumed by environmental priorities, particularly the impact that the decline of coal generation and the growth of renewable generation will have on costs and GHG emissions. A surge of subsidized renewable generation, combined with low natural gas prices, has driven wholesale prices steadily lower. As one would expect, in the short run this has benefited consumers in market-based states disproportionately more than those in regulated states.

Going forward, the role of intermittent renewable generation at both the wholesale and distributed levels is likely to continue to dominate the economics and policy of the industry. The low wholesale prices that have resulted from the expansion of subsidized renewables are not sufficient to cover the total cost of renewable or conventional sources, so the prominence of extramarket sources of revenue, such as above-market contracts and capacity payments, is likely to continue to grow. This will mean that even in the market states, the true cost of supply will increasingly diverge from the underlying price of the fundamental commodity, electrical energy.

At the retail level, distributed energy threatens to unravel the economics of retail distribution supply. Again, the juxtaposition of average and marginal costs is a driving force here, although the differences are exacerbated by inefficient rate making and political economy. Current rate-making practices encourage individuals to install DG systems, such as solar PV, that are privately economic because rates, which include the fixed costs of transmission and distribution, exceed the marginal cost of generated energy by a large margin. The next natural step in the rate-making process will be a move to two-part tariffs that include monthly charges decoupled from the volume of electricity consumed. There is speculation that the cost of storage technologies, perhaps deployed in a joint application such as with electric vehicles, could decline enough that households might bypass the grid completely (see Lacey 2014). Such an outcome would be a giant leap forward in technology, but it could be a step backward in economics if such decisions would again be motivated by an ability to shift sunk costs—this time of grid assets—onto other customers or utility shareholders. Policy makers again have a chance to make economically rational decisions based on true incremental costs. We can only hope that this time they will grab that opportunity.

DISCLOSURE STATEMENT

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