Markets and Efficient Pricing in the Electricity Sector

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Abstract

This paper studies the introduction of dynamic pricing in the U.S. electricity industry. We find that greater industry restructuring is associated with fewer dynamic pricing rates. Indeed, the likelihood of customers having dynamic pricing options declines with greater competition at either the wholesale or retail level; a relationship that holds whether the customers personally buy power from a regulated utility or an independent marketer. This result appears to put in conflict efficient pricing with the discipline of competitive markets. We discuss how the conflict may arise due to the current structure of the market in so-called competitive states.

JEL codes: L51, L94, O31, Q41, Q48

I. Introduction

Since Boiteux (1949), economists have argued for electricity retail tariffs that reflect the time-varying cost of generation. Potential efficiency gains from real-time pricing have grown: in addition to better aligning demand to marginal cost and to promoting peak shifting, dynamic prices are perhaps fundamental for large scale penetration of renewable generation and distributed storage, and for the implementation of efficient retail demand response programs.[1] Furthermore, advanced meters required to implement such tariffs have declined in price and are

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[1] See, e.g., Borenstein and Holland, 2005; Gambardella and Pahle, 2018; Carreiro, Jorge and Antunes, 2017.

widely deployed in the United States.[2] But dynamic prices – either time of use or real time – are still unusual in the residential and commercial sectors in the United States.

This paper studies the introduction of dynamic pricing in those sectors and seeks to understand the variation in the structure of tariffs in different regions of the country. Our key finding is that dynamic pricing is more likely to be an option in the absence of significant competition at either the wholesale or retail level. The result appears at odds with expectations for competition in the industry at the start of the restructuring movement. Joskow (2000), for example, anticipated that, conditional on availability of meters, competitive electricity service providers would offer dynamic price contracts in order to differentiate their products from competitors.[3] Competitive wholesale generation was expected to further promote dynamic retail rates, because competition at the wholesale level would encourage innovative generation technologies whose success would be enhanced by dynamic pricing. In consequence, a competitive wholesale sector would advocate for the establishment of dynamic retail tariffs.

We find the reverse: the likelihood of customers having dynamic pricing options declines with greater competition at either level.[4] The relationship is apparent is Figure 1. The top maps plot a measure of wholesale and retail competition by state. The lower map, which plots the availability of residential and commercial rates that vary by time, appears to be nearly a negative version of the competition maps.

[2] FERC, 2018.

[3] Advanced meters have been installed across the country, helped by handsome subsidies from DOE's ARRA account. In restructured states, the meters are installed and owned by distribution companies (always regulated) who avail themselves of the remote meter reading and enhanced reliability features and recover costs through standard rate of return billing. Massachusetts, among the states with the strongest competition in both wholesale and retail electricity, is an outlier, having recently declined to install smart meters in residences. See FERC, 2018; Commonwealth of Massachusetts, Department of Public Utilities Order 15-120, May 2018.

[4] Non-energy economists, and even some in energy, would argue that this has little to do with competition: instead, what we are measuring is the extent to which markets are served by private companies that are not subject to cost-based regulation. Competition in such markets can be, and sometimes certainly has been, deeply imperfect. We discuss this further below.

Our analysis does not impugn competition per se, but rather what passes for competition in U.S. electricity markets. That structure appears to hinder cooperation between actors in different sectors of the industry.[5] Efficiency benefits of dynamic pricing, at least in the context of the current industry, are estimated to accrue largely to the distribution and generation sectors of the industry, by enabling more efficient portfolios of generating plants and better strategies to ensure reliability.[6] But it appears difficult for generators and distributors to share the surplus with retailers who bear the initial burden of implementing the rates.

Furthermore, that burden is not insignificant. Experimental studies find that obtaining any price sensitivity in residential electricity settings requires a range of interventions beyond price, from marketing, nudging and the provision of information to installing equipment that automatically adjusts electricity use to price changes.[7] Efficient enterprise scale for introducing effective dynamic tariffs may be larger than the size of most retail power marketers, and feasible contract lengths longer than is common or sometimes even allowed in the industry. Consistent with this hypothesis, we find that controlling for competition and company type (retail power marketer or investor owned utility), larger firms are more likely to offer residential or commercial dynamic tariffs. Thus, our results suggest that even the residential-specific benefits of dynamic tariffs are external to smaller retail power marketers and, critically, that states with significant residential competition have not – perhaps not yet – established institutions to overcome these externalities.[8]

[5] The provision of reliable power is complex and subtle. See Borenstein and Bushnell, 2015, for a review of the industry and its restructuring in the United States.

[6] Borenstein, 2005; Horowitz and Lave 2014; Bushnell, Mansur, and Novan, 2017. See also Lautier, 2015, who finds similar results for France.

[7] Alcott, 2011; Kettler, Harding, and LaMarche, 2019.

[8] The lack of interest in dynamic tariffs by RPMs goes beyond the absence of such rates. All of the "Consumer Behavior Studies" – randomized control trials of dynamic rates funded by the Department of Energy under ARRA -- took place at investor owned utilities. We are unaware of any RCTs at a competitive RPM. See DOE, June 2015.

A third problem may emanate from the wholesale level. Load smoothing will not help all wholesale firms. With declining electricity use, more efficient dispatching does not mean, as it did forty years ago, that expensive investments are avoided. Rather, current generating units will be stranded – a concept of relevance to public utility commissions which continue to wield significant power in all states, including those with extensive wholesale competition. Furthermore, given the structure of wholesale markets in states with high levels of both retail and wholesale competition, it may be that no wholesale firm profits from load smoothing. As is discussed further below, in the absence of dynamic tariffs, the current relationships between customers, retailers and wholesalers in competitive states satisfy the conditions analyzed by Oi (1961) and Newbery and Stiglitz (1979) for greater demand volatility to increase profits in competitive industries.[9] Rather than promoting dynamic residential tariffs, merchant generators have an incentive to subvert their implementation.[10]

Our work contributes to several strands of research. A large literature looks at how markets for electricity contribute to efficiency, exploiting the variation in competition across states and time. It finds evidence of considerable efficiency gains from restructuring, albeit not as striking as in the deregulated transportation industries.[11] This research has concentrated on operational efficiencies such as fuel costs and plant availability. Tariffs constitute another facet of efficiency, with implications for efficient consumption, investment and innovation.

[9] Milstein and Tishler (2012) argue that in imperfectly competitive electricity markets, firms will underinvest in capacity so as to enhance demand spikes, although contrary to the evidence presented here, his distortion diminishes rapidly with the number of firms in the market. By contrast, Oi and Newbery and Stiglitz place no constraint on entry, which may be more relevant to competitive electricity markets today.

[10] A trade journal for the merchant power industry reflected gloomily on the industry outlook and load smoothing in 2018: “Simultaneously, energy margins are under pressure as wind and solar generation--which has been increasingly deployed over the past three years—has shaved off peak price formation” Industry Top Trends – North American Merchant Power 2018

[11] See Fabrizio, Rose and Wolfram, 2007; Davis and Wolfram, 2012; Bushnell and Wolfram, 2005. For a general assessment and review of this literature, see Bushnell, Mansur and Novan, 2017.

A second relevant area of research is in political economy. Policy changes create winners and losers; in a highly regulated sector like electricity, the distribution of benefits is relevant. For example, White (1996) and Ando and Palmer (1998) analyze the introduction of restructuring based on its geographically diverse economic consequences. Borenstein and Bushnell (2015) update this work and show that changes in economic conditions affect policies towards wholesale competition. This study follows a similar paradigm and builds on the work in these papers to understand rate policy.[12]

While we are not aware of any work that addresses the relationship between market structure and tariffs, Eid et al (2015) considers barriers to establishing residential demand response programs in European markets. Demand response is a technology with characteristics and aspirations that are in many ways analogous to dynamic tariffs. Focusing solely on markets that are relatively competitive by U.S. standards, they identify coordination among different actors in the industry as the primary barrier to adoption.

The remainder of this paper is as follows. The next section considers the benefits of dynamic tariffs in restructured markets in more detail and presents a stylized model of rate setting that motivates the reduced form model estimation and identification. We then discuss the data, followed by results, discussion and conclusions.

[12] Borenstein (2007) and Horowitz and Lave (2014) consider the redistributive consequences of real time prices among customer classes, which are large. We do not delve down into this level of detail at the company level, but it may be a fruitful area that further illuminates the choices made by companies to offer dynamic tariffs.

II. Modeling the choice of rates

In this section we first consider the incentives of wholesalers, retailers and consumers to support dynamic rates. We next look at the actual business of setting rates. In regulated states, public utility commissions approve and sometimes mandate a rate structure. While rates are within the purview of RPMs in the restructured states, we argue that a similar model may nevertheless be appropriate there, as the public sector still can exercise considerable persuasion and/or pressure. This discussion motivates our basic estimation model, and we then turn to a discussion of identification.

Wholesale markets are considered competitive in the United States when power is supplied into the grid by merchant generators, or Independent Power Producers, instead of (or perhaps alongside) generators owned by investor owned utilities (IOUs), public entities and others.[13] Figure 1a shows the variation across states in power sold by IPPs. Markets supplied by merchant generators may not be competitive in the usual sense; that is, these companies may be in a position to exercise considerable market power, especially when demand is strong. It may be more accurate to refer to these markets as deregulated or privatized rather than "competitive"; however, we maintain the standard usage in this paper. As is discussed further below, the argument for why wholesale firms may dislike dynamic rates rests on the separation of the industry into generation and distribution sectors, rather than the actual state of competition in either.

A system operator, usually an independent nonprofit entity, conducts auctions for day ahead energy, real time energy, and ancillary services needed to maintain the system, and prices the power, subject to various transmission constraints, at marginal cost. Various futures markets

[13] Public entities, including the federal power authorities, make up most of the balance in wholesale markets.

and financial side arrangements operate in the market, but power trades essentially at real time marginal cost.[14]

The other side of this market is composed of the entities that sell to final customers, including retail power marketers (RPMs), the IOUs, demand aggregators, municipal utility companies and, in some states, large industrial and commercial users. These entities enter bids specifying their demand for power at the relevant times. For companies that do not offer dynamic prices, the bids are simply demand projections: there is no need to bid in a schedule of demand conditional on price as the ultimate customers pay at a rate independent of the (immediate) market price. The consequence of this structure is that in regions where dynamic pricing and demand response options are rare, demand is largely exogenous to the wholesale price. From the suppliers' perspective, the market is subject to exogenous demand shocks.

Given that attribute, the work of Oi (1961) and Newbery and Stiglitz (1979) is directly relevant. Addressing the problem of commodity price stabilization, they show that in the presence of exogenous demand shocks, profits in competitive markets are enhanced by greater demand variability if the supply curve is convex. Intuitively, surge pricing during positive shocks more than offsets low prices during periods of low demand. Notwithstanding incentives to enter the market, firms at any point in time will still prefer demand volatility. In the electricity context, if dynamic pricing is the exception, merchant generators would oppose policies that promote peak shaving and that smooth demand – to wit, real time prices.[15]

In states with competitive retail sectors, consumers have a choice of companies from whom to buy power, including retail power marketers (RPMs) that may generate no power and

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[14] If the wholesale market is not competitive, the market price might, of course, not be competitive. That circumstance would still produce the incentive analyzed here for generators to prefer volatile demand. See Borenstein (2005) who argues that real time prices redistributes wealth to consumers from producers who exercise market power during high demand periods to drive up price higher than marginal cost.

[15] Note that in the absence of entry barriers we would expect that entry leads to excess capacity and normal competitive returns. Nevertheless, suppliers in the industry will still oppose policies that lead to less variability in demand.

typically own no distribution or transmission lines, and investor owned utilities (IOUs), that do. Figure 1b shows the variation across states in sales by RPMs. RPMs usually bill their customers for all components of service; in addition to energy this includes distribution and access charges as well as other components that the local public utility commission sees fit, such as "public service charges" to cover research and development and energy efficiency initiatives. Energy costs are only 60% of the wholesale cost of electricity on average (distribution accounts for 27% and transmission for about 12%) and comprise on the order of a third of the charges on residential bills, although with considerable inter-state variation.[16]

These modest energy charges, together with low demand elasticity, are at the heart of the analyses that suggest small savings or losses to any consumer from changing from average to marginal cost pricing.[17] Most residential customers in the United States pay a per-kilowatt hour fee that varies with total monthly consumption (an increasing block structure) but not with the time of consumption. Competitive retailers that serve such customers lose money when the wholesale cost of generation is high (peak periods) and profit when it is low. Clearly there is a Harberger penalty involved in the strategy, but for small RPMs it is modest. Balanced against that potential surplus are implementation costs, which include upfront efforts to enroll consumers and facilitate changing their use, or time of use, of electricity.[18] Given that consumers in competitive markets can switch suppliers, firms that pay the startup costs of implementing time-varying pricing could see other firms reap the benefits. Plausibly, smaller size and greater consumer choice for retail providers both work against any incentive an RPM may have to offer dynamic rates.

[16] From https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php

[17] See, e.g., Ito, 2014.

[18] The cost of advanced meters was expected to be the largest barrier to implementing realtime prices, but these have proven so useful for other purposes that distributors have installed them in much of the country. See, e.g., "What are the rules for Texas Smart meters?," TexasElectricityRatings.com, June 29,2018.

By contrast, investor owned utilities face a markedly different set of incentives. These firms generally retain their residential customers, can internalize any external benefits between retail and wholesale production, and are well advised to heed the preferences of public utility commissions. Customers of IOUs often have few or no alternative electricity providers to switch to. IOUs are typically larger than RPMs, making it easier to bear the fixed costs of a campaign aimed at educating customers about a new rate. The benefits of demand smoothing are captured by IOUs which conduct both generation activities as well as retail sales. Finally, IOUs necessarily have a close relationship with the public utility commissions that provide regulation and oversight of their activities. This relationship incentivizes a concern for the preferences of PUCs, which typically include lower retail prices and reliable supply[19]. Dynamic pricing fits that profile, at least in theory.

In summary, we hypothesize the following preferences for dynamic pricing: first that vertically integrated companies would be supportive; second, that consumers would be more or less neutral; third, that retail power marketers would have little interest in them; and fourth, that independent power producers would be generally opposed. Among all retailers, support for dynamic pricing is expected to increase with size. Other characteristics associated with support for dynamic rates might be the extent to which demand is variable or volatile, so that peak shaving and load smoothing is valuable, and characteristics of generating supply that determine the difference in marginal cost at different demand levels. (If marginal cost is constant across different demand levels, dynamic pricing is useless.)

Public utility commissions oversee rate structures for IOUs. Because rates are determined in public hearings that present opportunities for parties other than the IOU to attempt

[19] PUC preferences also include considerations of capacity; it is possible that adoption of time-varying prices would be avoided in the case where already existing generating might be stranded by a smoother demand curve. We anticipate that the difference between installed regional capacity and overall demand may be a useful control to include in the future.

to influence outcomes, we consider a rate setting model that allows balancing of interests. Alternatively, public utility commissions have no formal jurisdiction over retail power marketers. Nevertheless, it is reasonable to suppose that preferences of other parties – the wholesale sector and the nature of other retailers in the state – might be of relevance to RPM decisions. If, for example, IOUs comprise most of the retail sector, then RPMs might be able to free ride on investments made by those companies (or the public utility commission) in residential dynamic pricing. An interesting case in point is California, where the public utility commission has ordered all IOUs to implement time of use pricing by 2020. The PUC has identified a "default" time of use rate, and allows IOUs to implement more complex versions. While not required to do so, Community Choice Aggregators, who are mostly inexperienced, small (smallish) and compete for customers with IOUs, have indicated that they too intend to offer the PUC time of use default rates. [20]

We consider a probabilistic model of rate setting, where the likelihood of a firm offering a dynamic rate rests on a balancing of interests of the different electricity providers, both wholesale and retail, within the state as well as other variables that affect the value of having dynamic rates. We suppose that the IPPs have influence, but the retail side is more likely to prevail if the retail firms are large, whether they be RPMs or IPPs. The following model captures these principles:

[20] In California the proliferation of distributed solar make mid-day wholesale prices on sunny spring and fall days close to zero, while net metering means IOUs compensate solar homes at much higher marginal cost. California IOUs have embraced residential dynamic prices. Community choice aggregators are rapidly becoming a significant retail choice in some states, but account for only a very small portion of sales during the years for which we have rate structure data. See "California utilities prep nation's biggest time-of-use rate rollout," *UtilityDive,* 12/19/2019, https://www.utilitydive.com/news/california-utilities-prep-nations-biggest-time-of-use-roll-out/543402/ accessed 12/19/2019.

(1) $$Y_{iS} = \alpha_1 + \alpha_2 RetailCompetition_S + \alpha_3 WholesaleCompetition_S + \alpha_4 FirmType_i + \alpha_5 FirmSize_i + \alpha_6 WholesaleCompetition_S * FirmSize_i + \beta X + \varepsilon_{iS}$$

where Y_{iS} is an measure of the propensity of a firm *i* in state *S* to offer its residential and commercial customers dynamic rates, *FirmType* is an indicator variable for RTPs, *FirmSize* is measured in megawatt hours sold to residential and commercial customers and *X* is a vector of controls. Controls include variables intended to measure the value of dynamic pricing, as discussed above, that is, the extent of variability in demand and marginal costs over time.

Identifying the impact of competition is, as of course problematic. Retail competition only exists in states that have passed statutes restructuring the electricity systems from their 20th century origins. The conditions for wholesale competition – in particular, access to transmission grids – were set at the federal level, and, as Figure 1 shows, wholesale competition exists to some extent in most states. However, in some of the states with retail competition, the IOUs were required to divest their generating plants. Not surprisingly, these states are likely to have higher levels of IPP participation in the wholesale markets.

Two questions thus arise: first, is there endogeneity in the competition variables, and second, are there omitted variables that might be related to both the existence of dynamic rates and the extent of retail or wholesale competition. Endogeneity seems unlikely due to timing: dynamic rates, particularly for residential and commercial customers, are recent phenomena, postdating statutory conditions for competition by over a decade. On the other hand, the existence of variables related to both competition and rate structure is likely. Ideally we would employ an instrumental variable or search for policy change. Neither of these strategies is possible. We found no plausible instrument for competition that survived the exclusion requirement, while a panel approach is frustrated by the short length of time that rate structure data is available.

Instead we have attempted to control for likely simultaneity. One source might be average retail prices. High price states were more likely to have been restructured, and typically still have high costs which directly enhance the value of dynamic rates today. We include average retail prices from the mid-1990s in the estimation. White (1996) identifies the gap between a system's average and marginal cost as important to whether states chose to restructure. Borenstein and Bushnell (2015) consider a similar pattern, focusing on how regulators responded to stranded costs with efforts to encourage competition. Again, both characteristics of system costs affect the value of dynamic pricing. For controls we include the share of generation from coal, gas, and other sources by state.[21] Finally, while partisan politics seems to be less important to the history of electricity competition than might be expected, we allowed for the possibility that state politics or demographics might affect both preferences for dynamic prices and preferences for electricity competition by including partisan measures, demographic measures, and whether the state's public utility commission is appointed or elected. Definitions for the independent variables are contained in Table 1.

[21] Some recent work has argued that restructured states are more likely to invest in renewable energy, another technology that enhances the value of dynamic prices. (Lee, 2018) The evidence in our sample for this proposition is weak, but we also considered shares of solar and wind in the analysis. During our sample period, California dominated by far solar generation, and Texas did the same for wind, so that the "renewable" results were entirely dependent on activities within those states and offered no broader insights.

III. Data

Individual utilities are the unit of observation for this analysis. We combine administrative datasets from multiple government agencies to develop a picture of how characteristics at the firm, state, and balancing authority-level contribute to the choice of menu offerings for electricity tariffs available to consumers. More than 3000 firms are observed at the operating company level each year from 2015 to 2017, but our analysis is primarily restricted to the approximately 1100 firms with an ownership structure described as "Investor Owned" or "Retail Power Marketer".

Ownership structures are reported to the EIA. Investor owned utilities (IOUs) are privately owned and provide a public service. In 2017, these 259 firms represent eight percent of firms in our sample but have sixty three percent of all electricity customers nationally. Retail Power Marketers (RPMs) are entities that market power to customers in restructured markets. There are 912 RPMs in 2017, representing twenty eight percent of firms in the sample. However, only ten percent of electricity customers are served by RPMs. This size difference is reflected in the quantity of electricity sold by each type of firm. Figure 1 shows the distribution of sales (in MW) by IOUs and RPMs. Investor Owned utilities tend to be larger than retail power marketers. We further restrict the sample to include only firms who serve residential customers, and due to various idiosyncrasies, drop Alaska, Hawaii and the District of Columbia from the sample. This leaves 185 IOUs and 621 RPMs in 2017 (and approximately the same number and characteristics in 2016 and 2015). (see Tables 2 and 3)

Data on firm characteristics is taken from the Energy Information Agency (EIA) form 861. Form 861 collects information from "industry participants involved in the generation, transmission, distribution, and sale of electric energy in the United States" (EIA 861). Our outcome of interest comes from a question introduced in 2013. Firms report the type of time-varying pricing available to customers: time of use, real time, variable peak, critical peak, or critical peak rebates. Firms also report the total number of residential, commercial, industrial, and transportation customers that have enrolled in one of the time-varying pricing programs available. However, the number of customers is not reported separately for each type of time-varying price offered by the utility.

Due to the very small number of actual enrollees in these programs, we analyze the existence of such programs, rather than actual enrollment. Most of the residential and commercial programs are time of use; currently very few utilities offer real time prices. In the interest of inclusion, we combined all dynamic options, and constructed a variable that takes on the value of one if the company has any type of dynamic tariff which is offered to residential or commercial customers.[22]

Form 861 includes other firm-level details for each utility. Utilities report their size in terms of total customers, total MW sold, and total revenue. Characteristics also include summer and winter peak demand, whether the firm engages in generation, transmission, or distribution activities, and a measure of net power exchanged with other utilities. We compute the share of power in a state sold by RPMs to measure the degree of competition in that retail market.

EIA Form 923 collects “detailed electric power data -- monthly and annually -- on electricity generation […] at the power plant and prime mover level” (EIA 923). In particular, the EIA publishes a report titled ‘Detailed State Data’ which aggregates plant-level generation data to the state level. We calculate the share of power in a state generated by Independent Power Producers (IPPs) as a measure of the degree of competition in the wholesale electricity market.

[22] In parts of the country industrial customers are required to participate in dynamic tariffs, or at least interruptible rates. In addition, some RPMs serve only industrial customers and have very different corporate structures than those that serve residential and commercial customers. Due to these differences, as well as both political and economic distinctions between the different sectors, we have limited our analysis here to the residential and commercial sectors only.

Other state-level characteristics include the share of power generated by coal, natural gas, solar, and wind power plants each year.

Finally, hourly grid load at the balancing or planning authority level is taken from the Federal Energy Regulatory Commission Form 714. Planning authorities often cover multiple states; dispatch decisions and wholesale markets occur at the planning authority level. Time-varying pricing is a demand smoothing measure, which is most valuable in regions with high intra-day volatility in electricity demand. We construct an index of dispersion to measure this volatility. The dispersion index is the standard deviation of hourly demand divided by the mean hourly demand in a planning authority area. This information is not available for all balancing authorities. In particular, FERC does not report data for the major IOUs in regulated Southern States. The EIA has equivalent data starting in 2015, which we have used as needed.

IV. Results

We estimate equation (1) using a probit regression with robust standard errors clustered by state. Due to data limitations, we restrict the analysis here to three years, 2015, 2016, and 2017.[23] Summary statistics are reported in Table 4 and results in Table 5. Average marginal effects are reported in Table 7.

The data reveal that at least in one respect, dynamic rates respond to economic opportunity. The likelihood of such tariffs being in existence is strongly related to demand dispersion, which measures load variation. Dynamic rates are valuable when demand is variable. Marginal cost is then also typically variable, so that average and marginal costs diverge. In addition, the variation means load shifting off-peak will be cost reducing.

Dispersion should be a function of the rate structure: dynamic rates should shift demand and result in lower dispersion. We considered the possibility of endogeneity by using dispersion in 2006 both as an instrument for current dispersion and as the explanatory variable itself, hypothesizing that the earlier conditions in demand led to a change in pricing policy. The IV approach failed,[24] but using lagged dispersion yields equivalent results. The downside of this procedure is that there have been changes in the boundaries of firms and balancing authorities, so that the earlier data only approximates relevant wholesale markets today. Results for the competition variables are unaffected by use of earlier dispersion data, and those for dispersion itself are qualitatively identical.

Firm size is a strong predictor of dynamic rates, consistent with both the existence of fixed startup costs or externalities from dynamic pricing. The result is at odds with theoretical

[23] And note that we are still missing some of the IOUs from southern states at this time

[24] 2006 dispersion and current dispersion are very highly correlated, and the procedure uncovered no evidence that the lagged variable corrected for endogeneity in the contemporaneous. Takeup rates at this time for the contracts are so low that it is perhaps unreasonable to expect to find any resulting load-shifting or peak suppression.

treatments, which find that the retail-side benefits of dynamic pricing decline as such tariffs become widespread and the gap between peak and off-peak prices decline.[25]

The fuel types at use in states do not appear to explain the difference in rates, although as is discussed below, there is some evidence that investor owned utilities in states with a larger component of natural gas in their fuel mix are less likely to offer dynamic rates. States with strong IPP presence in wholesale markets on average have far less coal generation and less wind and solar than those states dominated by IOU generation; but we do not measure any statistical impact of the fuel mix on rate structure policy at this time.[26] Similarly, none of the political or demographic variables that we looked at directly affect rate structure for the full sample of firms (conditional on other covariates like the index of dispersion in hourly demand). This is in line with earlier work on industry restructuring.[27]

The results confirm the hypothesized negative relationship between competition and dynamic rates. As Table 3 shows, some kind of dynamic contract is offered by over half the IOUs in our sample, but by less than five percent of the RPMs. Furthermore, the IOUs are on average larger than RPMs (see figures 2 and 3). After controlling for whether a firm is an RPM or not, as well as for size, residential or commercial dynamic rates are more likely to be offered when retail markets are less competitive. These results are significant at standard statistical levels.

These relationships hold even when restricting the sample to only firms with the same kind of ownership structure. Table 6 reports the estimated coefficients and marginal effects for the probit model estimated using only investor owned utilities (column 1-3) or only retail power

[25] Borenstein and Holland, 2005.

[26] As is discussed above, distributed solar power gives a strong incentive to retailers to adopt real time or time of use rates. This change is now underway in California, which is an outlier in distributed solar generation, but post-dates our sample. For robustness we checked on results omitting California entirely, and also Texas which has a high concentration of RPMs. The results survive.

[27] We ran the regressions omitting all of the demographic and political variables and obtained identical results for the remaining covariates.

marketers (column 4). IOUs in states with more natural gas generation are less likely to have dynamic rates, while those in more educated states appear somewhat more likely. However, overall the demographic and political variables continue to offer few insights into decisions of rate structure. The negative relationship between time-varying pricing and competition is qualitatively the same for both groups, though the small number of adopters among RPMs leads to a noisier estimation.

The relationship between wholesale competition and dynamic rates depends on the size of the retail firm (whether IOU or RPM). Note that the average marginal effect, reported in Table 7, for wholesale competition is small and insignificant for the whole sample as well as for the IOUs and RPMs estimated separately. Table 8a and 8b report marginal effects estimated at different firm sizes. Table 8a contains marginal effects estimated at the sample deciles – that is, the deciles calculated for the entire sample. For the sample as a whole, greater wholesale competition significantly reduces the likelihood of a company offering dynamic rates for companies in the lower half of the size distribution. The relationship remains negative, although not significant, through the 80^{th} percentile of firms. This relationship holds with less precision for the RPMs. The IOUs appear less susceptible to wholesale competition effects in their pricing decisions: the marginal effects are positive and significant only for IOUs in the two smallest population deciles, although the relationship continues to be negative up to the 60^{th} percentile. The table includes retail competition marginals calculated at the same percentiles. By contrast, these are fairly stable across size, possibly even having a somewhat larger negative impact on the larger retail firms.

As the IOUs are concentrated at the higher end of the sample size distribution and the RPMs at the lower end, we also calculated the marginal effects for deciles of the distinct IOU and RPM distributions. These are reported in Table 8b. Only five percent of IOUs are in the smallest twenty percent of the entire sample, while about 40% of the RPMs are in the smallest 30% of the sample.

The results thus suggest that greater participation in wholesale markets by IPPs is associated with less retail dynamic pricing for smaller firms and for RPMs. Most of the IOUs are subject to the other factors analyzed here – most importantly, the level of retail competition, company size, and demand dispersion – but only the smaller IOUs appear to be affected by wholesale competition in their own decisions about retail pricing. This is broadly consistent with the discussion in section 2, as we would expect IOUs, and especially large IOUs to have considerably more influence with state regulators than merchant generators.

V. Conclusions

This paper looks at the introduction of residential and commercial time-varying prices in the electricity industry. We find that states that have actively restructured their industries are laggards. Greater retail competition appear to inhibit the introduction of dynamic rates, while greater wholesale competition does so for smaller firms and particularly for retail power marketers.

Albeit standard usage, "competitive" is something of a misnomer here. So-called competitive wholesale markets for electricity are characterized by the presence of generation firms that are not subject to cost-based regulation, and do not also transmit or distribute power.[28] The extent to which those companies can exercise market power is difficult to ascertain, but certainly some "competitive" markets have at times been characterized by monopolistic pricing and dispatch behavior, usually when demand is strong. Similarly, "competitive" retail markets are characterized by customer choice and companies that specialize in retail sales; these markets may still have high degrees of concentration according to merger-guideline standards.

However, the discussion in section 2 suggest that the results may have little to do with actual competition, but rather with the structure of the industry in restructured states: that first, there are distinct wholesale and retail sectors; second, that the retail sector is composed of relatively small firms; and third, that the wholesale sector is not subject to cost-based regulation. That structure produces both resistance to dynamic prices by retailers – who have difficulty capturing any benefits from demand response or peak shaving – and by wholesalers, who should eschew policies that stabilize demand.

Wholesalers have no direct control over the pricing policy of retailers, but we posit that in an industry with pervasive public involvement, even in restructured states, they can be

[28] Or at least the generation sector is organizationally distinct from such activities in the corporate sense.

influential. Our analysis is consistent with the existence of such influence. We find that when a large share of wholesale power is provided by Independent Power Producers, RPMs and small IOUs are less likely to offer time varying prices to their residential or commercial customers. Alternatively, if the retailers are themselves large (either IOUs or RPMs), their choice of rate structure appears to be unaffected by the wholesale situation. This too is consistent with standard collective choice principles. Merchant generators appear less able to exert influence when retailers are large.

We find that larger retail companies are more likely to implement dynamic tariffs (whatever their regulatory status), than small companies. Plausibly, small retail companies find it harder to cover the costs of implementing dynamic prices, are more greatly penalized by scale economies in implementation, and find it even more difficult to coordinate with upstream companies.

The electricity sector, whether deregulated or more integrated, requires close collaboration between upstream and downstream companies. In restructured states, distribution companies and system operators integrate activities. Furthermore, in many states, including states with fragmented retail companies, distribution companies have installed advanced meters. The meters have value outside allowing dynamic prices, as they allow remote meter reading, provide real time information about system problems, and transmit data about usage patterns that enhance system operations. Thus, a natural institutional structure appears to exist in the industry that allows surplus to be shared among upstream and downstream companies. Nevertheless, in states with fewer regulated firms at the generation and retail level, rate setting that depends to some degree on integrated activities between the different sectors is not common – perhaps because the IPPs would much rather not.

Electricity pricing is in flux. Our analysis addresses the pattern of early adoption of dynamic rates. While there are indications that adoption of dynamic rates will broaden, early adoption is critically important for innovation, especially for complex technology whose success depends on actions by multiple industry sectors. To the extent that the electricity industry continues to deregulate, we need to better understand how to facilitate the development of institutions that coordinate among actors and allow innovations not just in pricing but other cross-sector technologies.

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Table 1: Variables and sources

Variable name	Definition	Source
Dynamic rates	Indicator variable for whether the retailer (IPP or RPM) offers any time varying rates to residential or commercial customers	EIA 861
Retail competition	Within a state, the fraction of power sold by IPP and RPM that is supplied by RPM	EIA 861
Wholesale competition	Within a state, share of power generated by Independent Power Producers	EIA Detailed State Data
RPM	1 if the retailer is a retail power marketer	
Size	Log of the annual MWH sold by the company to residential and commercial companies	EIA 861
Interaction	Wholesale competition * size	
Dispersion	Within a planning authority area, standard deviation of hourly demand divided by average hourly demand.	FERC 714 & EIA Hourly Electric Grid Monitor historical data API
Natural gas share	Within a state, share of power generated by natural gas	EIA Detailed State Data
Coal share	Within a state, share of power generated by coal plants	EIA Detailed State Data
Solar share	Within a state, share of power generated by solar plants	EIA Detailed State Data
Wind share	Within a state, share of power generated by wind	EIA Detailed State Data
Average price 1996	Average revenue per KWH for electricity in the state for all customers	Electric Power Annual Volume 1 1996
Elected_Public Utility Commission	1 if the PUC is elected; 0 if appointed	Book of the States 2016
Ada	Average ADA score of state's congressional delegation	Americans for Democratic Action
Education_level		American Community Survey
Per_capita_income		American Community Survey

Table 2: Characteristics of sample firms, 2017.

Ownership Type	Number of Firms in Sample	Share of Total Residential and Commercial Energy	Share of Total Residential and Commercial Customers
Investor Owned Utilities	185	56%	60%
Retail Power Marketers	621	16%	12%

Table 3: Distribution of sample Retail Power Marketers and RPMs with dynamic tariffs by State

State	# RPMs in 2017 serving residential customers	# RPMs with dynamic tariffs
CA	2	0
CT	32	1
DE	23	0
IL	61	2
MA	41	2
MD	57	1
ME	11	1
NH	17	1
NJ	64	3
NY	62	4
OH	70	1
PA	81	3
RI	13	1
TX	61	5

Table 4: Sample statistics

Variable name	Mean	Standard Deviation	Min	Max
Dynamic rates For IOUs For RPMs	18% 62% 4%		0	1
Retail competition	.35	.20	0	.84
Wholesale competition	.73	.28	0	.99
RPM	.76		0	1
Size	12.13	2.64	1.1	18.48
interaction	8.56	3.57	.01	16.20
Dispersion	.24	.86	.12	18.98
Natural gas share	.36	.21	0	.96
Coal share	.23	.21	0	.94
Solar share	.006	.013	0	.12
Wind share	.04	.06	0	.37
Average price 1996	.08	.02	.04	.12
Elected_Public Utility Commission	.04		0	1
ADA	56.35	24.15	8.31	98.12
Education_level	.224	.04	.14	.30
Per_capita_income	52,765	7,666	35,524	69,094

Table 5a. Regression results, full model and full sample

Dependent variable = 1 if company offers any form of dynamic rate to residential or commercial customers. All years estimated jointly; errors clustered by state; standard errors in parentheses

Variable	2015	2016	2017
Retail competition	-.794** (.398)	-.783** (.363)	-.667** (.298)
Wholesale competition	-3.120*** (1.223)	-2.723** (1.297)	-2.372* (1.44)
RPM	-1.178*** (.169)	-1.355*** (.190)	-1.456*** (.199)
Size	.165*** (.057)	.206*** (.063)	.183** (.076
Wholesale comp * size	.192** (.088)	.174** (.088)	.155 (.099)
Demand dispersion	11.875*** (3.926)	14.330*** (4.128)	8.529** (3.645)
Natural gas share	-.964 (.677)	-1.122* (.612)	-.614 (.480)
Coal share	-.599 (.722)	-.207 (.717)	.093 (.014)
Average retail price 1996	-.018 (8.170)	5.319 (7.932)	3.951 (6.987)
Elected Public Utility Commission	-.225 (.292)	-.179 (.284)	-.301 (.281)
ADA (house delegation average)	-.000 (.006)	.003 (.005)	-.002 (.004)
Education_level	-2.583 (5.175)	-3.430 (5.075)	3.084 (3.452)
Per_capita_income	.000 (.000)	.000 (.000)	.000 (.000)
Year dummy variable		-1.211** (.593)	-.214 (1.05
Constant	-4.401*** (1.540)		
n	716	764	806
Prob > chi2 = 0.0000			
Pseudo R2 = 0.5033			

Table 5b: Regression results, full model without political, demographic, generating system controls

Dependent variable = 1 if company offers any form of dynamic rate to residential or commercial customers; standard errors clustered by state; years estimated jointly

Variable	2015	2016	2017
Retail competition	-.977*** (.265)	-1.097*** (.243)	-1.024*** (.199)
Wholesale competition	-3.290*** (1.203)	-2.922** (1.214)	-2.263* (1.346)
RPM	1.113*** (.160)	-1.267*** (.181)	-1.386*** (.197)
Size	.143** (.058)	.175*** (.063)	.163** (.073)
Wholesale comp * Size	.222** (.090)	.214** (.088)	.179* (.096)
Dispersion	9.298*** (3.068)	11.337*** (3.466)	7.181** (3.029)
Year = 2016 or 2017		-.873** (.450)	.260 (.862)
Constant	-3.501*** (.855)		
Prob > chi2 = .0000; Pseudo R2 = .495			

Table 6, results by type of retail company

Dependent variable = 1 if company offers any form of dynamic rate to residential or commercial customers; standard errors clustered by state.

	IOUs only			RPMs only
Variable	2015	2016	2017	2016/2017
Retail competition	-1.685** (.831)	-1.659** (.755)	-1.565** (.760)	-1.701* (.91)
Wholesale competition	-5.610** (2.404)	-3.102 (2.065)	-5.084** (2.416)	-3.285* (2.05)
Size	.181*** (.068)	.240*** (.078)	.179** (.085)	.103 (.118)
Wholesale comp * size	.391** (.173)	.252* (.151)	.390** (.185)	.222 (.158)
Demand dispersion	17.497*** (4.119)	19.445*** (4.894)	10.865*** (3.981)	17.124* (10.22)
Natural gas share	-2.322** (1.021)	-2.242** (1.066)	-1.498* (.927)	
Coal share	-.703 (.995)	-.306 (1.051)	.063 (.948)	
Average retail price 1996	-7.701 (12.938)	-7.901 (14.772)	-3.455 (14.106)	
Elected Public Utility Commission	-.057 (.239)	-.050 (.231)	-.251 (.264)	
ADA (house delegation average)	.002 (.009)	.007 (.010)	.000 (.010)	
Education_level	-3.877 (7.401)	-6.524 (8.189)	1.352 (6.900)	
Per_capita_income	.000** (.000)	.000* (.000)	.000 (.000)	
Year dummy variable		-.942 (.743)	1.423 (.984)	
Constant	-6.522*** (1.720)			
N	182	178	178	1198
	Prob > chi2 = 0.000; Pseudo R2 = 0.271			Prob > chi2 = .0000 Pseudo R2 = .143

Notes: years estimated jointly for IOUs; years pooled for RPMs. Additional controls omitted for RPMs due to lack of variation

Table 7. Average marginal effects

Variable	Full Sample	IOUs only	RPMs only
Retail competition	-.097** (.042)	-.451** (.192)	-.125* (.072)
Wholesale competition	-.039 (.061)	.125 (.301)	-.023 (.033)
RPM	-.172*** (.017)		
Size	.037*** (.002)	.091*** (.008)	.021*** (.003)
Dispersion	1.488*** (.478)	4.397*** (.981)	1.258 (.792)
State Share Natural Gas	-.116 (.073)	-.558** (.251)	
Per capita income	2.28e-06 (2.51e-06)	1.39e-05* (8.24e-06)	
Other demographic, political, generation system controls	Yes	Yes	No
Years included	2015, 2016, 2017 (Table 5a)	2015, 2016, 2017 (Table 6)	2016, 2017 (Table 6)

Table 8: marginal effects for competition variables by firm size percentile; other variables evaluated at sample average

8a. Marginal effects by full sample decile

Size	Full Sample		IOU only		RPM only	
	Wholesale Competition	Retail Competition	Wholesale Competition	Retail Competition	Wholesale Competition	Retail Competition
10%	-.067*** (.025)	-.043** (.020)	-.238** (.100)	-.261* (.141)	-.013** (.006)	-.018* (.011)
20%	-.075*** (.026)	-.058** (.026)	-.223** (.109)	-.338** (.162)	-.023** (.011)	-.038* (.024)
30%	-.081*** (.031)	-.071** (.032)	-.196 (.136)	-.399** (.182)	-.031* (.017)	-.063* (.038)
40%	-.084** (.038)	-.085** (.038)	-.160 (.170)	-.452** (.202)	-.037* (.023)	-.092* (.055)
50%	-.085* (.047)	-.100** (.044)	-.117 (.207)	-.495** (.221)	-.042 (.032)	-.124* (.074)
60%	-.084 (.059)	-.118** (.052)	-.060 (.250)	-.532** (.238)	-.043 (.043)	-.167* (.099)
70%	-.077 (.080)	-.145** (.064)	.027 (.307)	-.559** (.249)	-.037 (.065)	-.236* (.138)
80%	-.050 (.122)	-.190** (.082)	.155 (.363)	-.539** (.232)	-.001 (.119)	-.362* (.208)
90%	.005 (.178)	-.234** (.100)	.241 (.354)	-.446** (.179)	.080 (.209)	-.504* (.283)

8b. Marginal effects by firm-type decile

Size	IOU only		RPM only	
	Wholesale Competition	Retail Competition	Wholesale Competition	Retail Competition
5%	-.221** (.112)	-.347** (.165)		
10%	-.157 (.172)	-.455** (.204)	-.011** (.005)	-.014 (.009)
20%	-.026 (.274)	-.546** (.244)	-.019** (.009)	-.030 (.019)
30%	.104 (.346)	-.557** (.244)	-.027** (.014)	-.050* (.030)
40%	.162 (.364)	-535** (.229)	-.032* (.018)	-.068* (.042)
50%	.197 (.367)	-.508** (.213)	-.037* (.023)	-.092* (.055)
60%	.227 (.362)	-.472** (.193)	-.041 (.031)	-.123* (.073)
70%	.246 (.349)	-.472** (.192)	-.042 (.039)	-.053* (.091)
80%	.257 (.331)	-.391** (.154)	-.041 (.054)	-.204* (.120)
90%	.260 (.310)	-.346** (.136)	-.026 (.084)	-.286* (.166)

Figure 1a: Share of competitive (IPP) generation in state, 2016

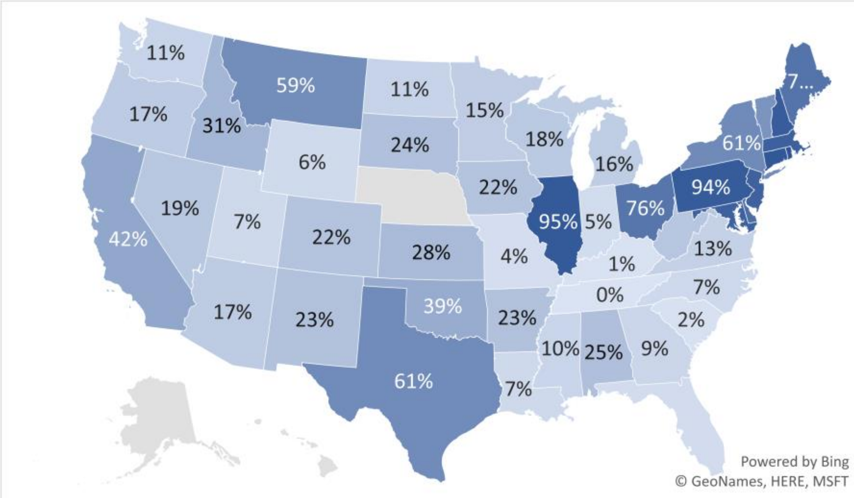

Figure 1b: share of retail sales by competitive companies (RPMs), 2016

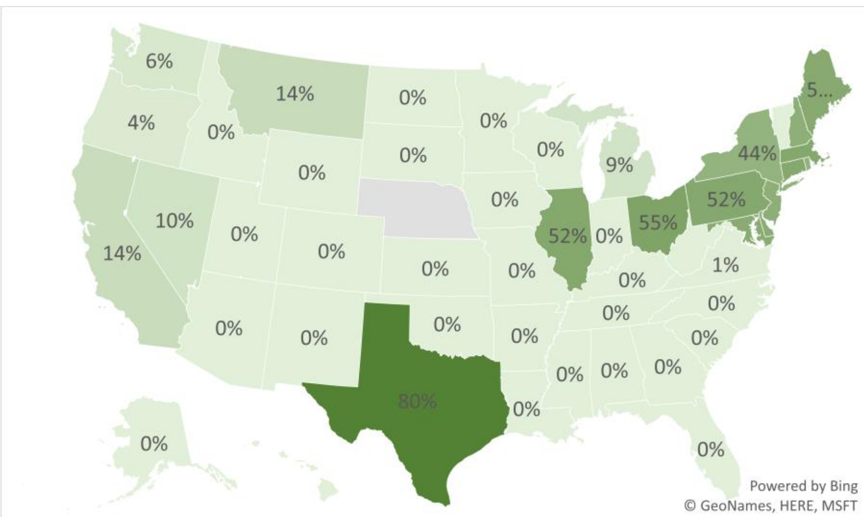

Figure 1c: Share of companies with any dynamic retail rates, 2016

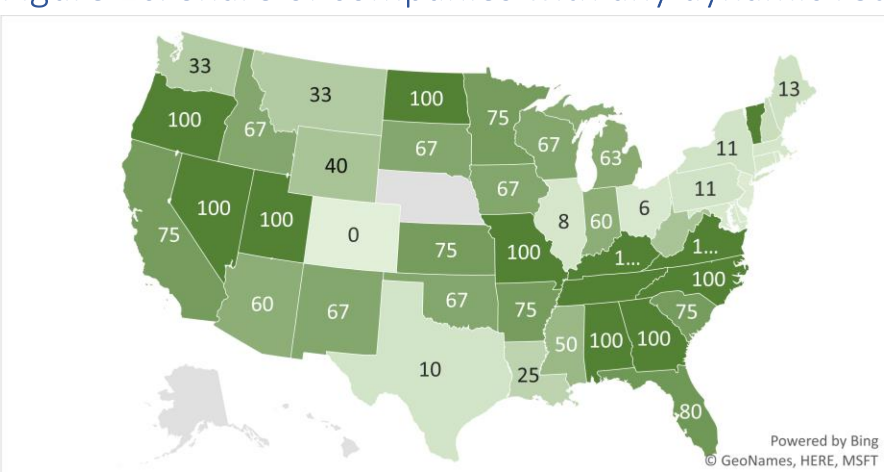

Figure2: Size of Retail Power Marketers and Investor Owned Utilities

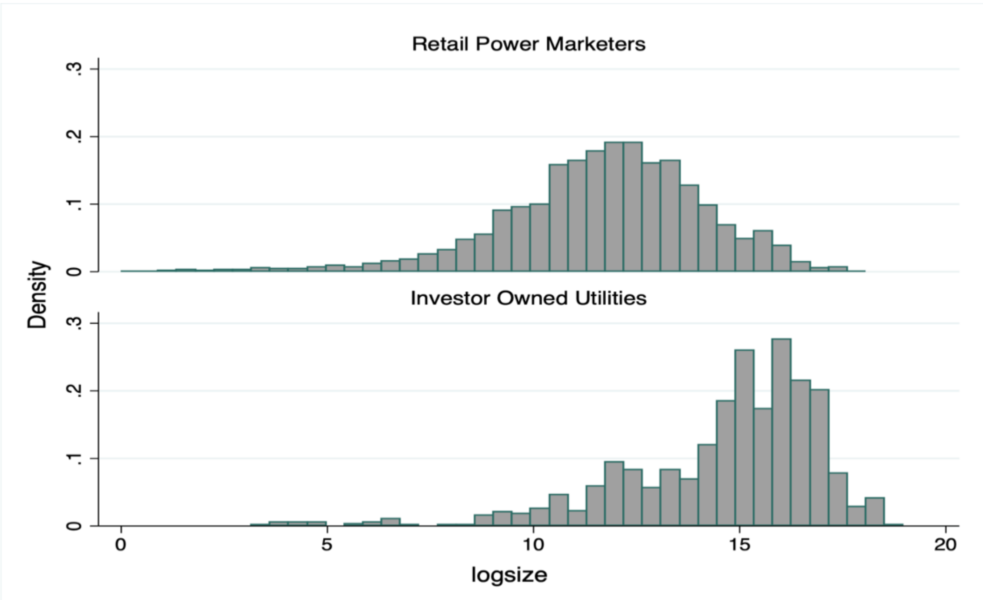

Figure 3: Size of firms that do/do not offer time-varying pricing