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Electricity rates for the zero marginal cost grid

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ABSTRACT

The electricity industry is rapidly changing: costs are increasingly dominated by capital and technology is turning loads into resources. This is similar to the early days of the Internet. Building on rate-structures used in the communications industry, utilities of the future should offer customers a portfolio of service contract options that provide a signal to the utility regarding the type and amount of infrastructure that should be deployed.

1. Introduction

The rapid growth of variable wind and solar generation, along with cheap natural gas and stagnant demand growth, have led to substantial declines in wholesale electricity prices, to levels not seen in two decades or more. Wholesale cost declines have not been reflected in retail prices because of increasing fixed costs and the costs associated with state electricity programs. Retail el ectricity costs are increasingly driven by the capital costs associated with replacing aging transmission and distribution infrastructure and building new wind, solar, natural gas and (increasingly) energy storage capacity. Fixed costs are becoming a larger fraction of customers' bills.

This trend can be clearly seen in recent wholesale and retail prices in the PJM Interconnection, which serves much of the Mid-Atlantic U.S. (see Fig. 1). In this region, stagnant electricity demand and cheap natural gas have led to significantly lower wholesale costs. Growth in renewable energy in the region and growth in demand response have also been factors. Despite a 25% decline in wholesale energy and capacity costs, retail prices in several states within PJM have actually increased. The widening gap between retail and wholesale prices is due in large part to the growth in state-level customer charges. The increase in state tariff costs are driven by a number of factors, including capital for transmission and distribution, and programs that support renewable and low-carbon energy.

A second notable trend is the emergence of new enabling technology for flexible demand. The potential value of demand-side flexibility has been recognized for decades (Morgan and Talukdar, 1979; Schweppe et al., 1980). In order to test this value, many utilities implemented direct load control programs that used timers or radio broadcast signals to remotely disconnect loads during peak periods. However, these legacy programs could not guarantee customer quality of service, reducing customer adoption rates, and were narrowly limited to providing peak reduction services. The potential value of these types of programs, particularly in a system with large amounts of variable renewables, has declined as the sophistication of automated grid-connected devices has increased. New smart thermostats and load coordination software systems can enable aggregated grid edge devices, such as water heaters, pool pumps, and HVAC thermostats, to provide grid services that are very similar to that provided by grid-scale battery systems. When employed effectively, grid services from these distributed energy resources can balance the variability of wind and solar generation and eliminate or defer the need for new capital investment for grid assets.

In an electricity system where capital represents a large fraction of electricity costs and marginal operating costs are approaching zero, the historical models for both wholesale and retail pricing of electricity are being increasingly challenged (among the many recent pieces on this topic include Faruqui et al., 2016; Frew et al., 2016; RAP, 2017; Bielen et al., 2017; NARUC, 2016). It is increasingly clear that flat volumetric electricity rates with small fixed charges are insufficient to align consumer incentives with the costs that electric utilities face. The availability of new technology means that we are no longer constrained to work with simplistic flat rate structures. The ideal electricity rate structure would encourage customers to engage in behaviors that are beneficial to the system as a whole. Neither flat volumetric tariffs nor rates that depend on dynamic pricing accomplish this goal in a

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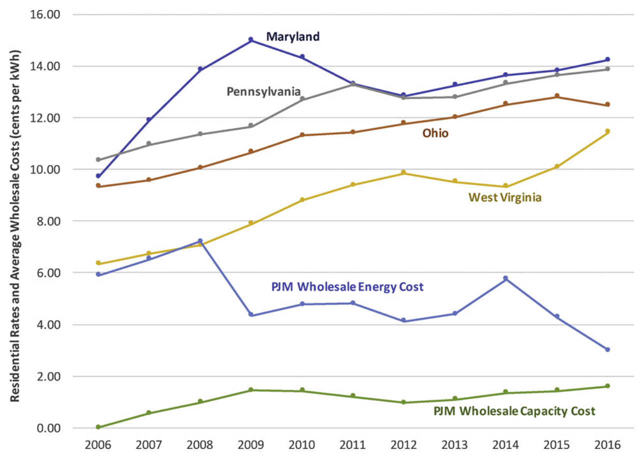

Fig. 1. PJM wholesale costs and some residential retail rates in PJM's market footprint. Source: Author calculations using data from PJM (wholesale cost and load data) and the Energy Information Administration (state average retail prices).

changing power grid where energy is nearly free (at the margin) and a the components of the grid have a high degree of automation. We believe that any financial engagement between the utility and consumers should be designed to do the following:

- Encourage customers to shift demand to times when capacity constraints are not binding.
- Encourage new uses of electricity that leverage under-utilized capacity.
- Promote equity and affordable energy access for low- and moderate-income electricity customers.
- Provide a clear signal from customers to electric utilities regarding the amount and type of infrastructure capacity that customers actually want the utility to build, rather than reflecting the average costs of historical utility decisions.
- Allocate costs, benefits and risks equitably, fairly and transparently among customers.
- Minimize surprises and unintended consequences (such as cost shift and/or unplanned rate increases) by applying a systematic, methodical, holistic and portfolio approach to rate design
- Promote performance-based competition between traditional grid infrastructure and DER investment decisions to keeps rates affordable (unleash load as a resource systematically and at scale)
- Integrate DER solutions as an extension of grid infrastructure for planning, operation and optimization to minimize stranded cost and maximize economic value of DER investments

If retail electricity rates could meet these goals, overall costs would go down and affordable, reliable decarbonization would be easier (e.g., by changing volumetric rates that discourage electrification), providing benefits for everyone. Moreover, by harnessing the inherent flexibility of many electric loads, the utility can shape overall consumption to both reduce costs and greatly simplifying planning processes.

The questions that we address in this paper are what kind of rate structure will best achieve these aims, and how can power systems engineering be adapted to ensure that consumers experience no negative impact even when they are offering significant flexibility to the grid.

2. Existing dynamic rate structures and their challenges

While flat volumetric rate structures continue to be common in practice, utilities have tested a wide range of alternative approaches. Most of these use some form of dynamic pricing, in which prices change periodically according to a set of rules, based on grid and market conditions. Here we review several of the most common dynamic rate structures.

The most common dynamic rate is a time of use (TOU) structure with pre-defined peak and off-peak prices over fixed and pre-determined time intervals. Utilities have used TOU rates for years, and the literature is fairly clear that these rates do produce some load shifting between peak hours and off-peak hours (Faruqui and Sergici, 2010). The TOU is, however, a blunt tool with several shortcomings.

The first shortcoming from simple TOU pricing is that rates are set based on historical diurnal patterns of peak and off-peak demand, under the assumption or determination that peak demand is more expensive to serve. As the technologies that supply electricity change, these historical definitions of 'high cost on-peak' and 'low cost off-peak' are increasingly breaking down. Under a TOU rate, there are many days in which customers would be paying the higher peak rate when there are no active capacity constraints, so that the marginal cost of energy is relatively low (for example, due to high wind power production). In these cases, an optimal solution from the perspective of the system as a whole is to increase demand by doing useful work, such as charging electric vehicles or turning on water heaters. Similarly, the combination of variable wind and solar and unexpected transmission or generation conditions can result in capacity constraints outside of normal peak hours. In engineering terms, TOU rates cannot solve a dynamic control problem because the rate structure is an "open loop" solution.

A more significant challenge is the impact of automation. Consider the model of a future California power system considered by Cammardella et al. (2018), in which millions of devices such as thermostats, water heaters, refrigerators and pool pumps participate in a time-of-use program with peak hours in the early evening. If these loads were set on a simple timer, they would consume no electricity during the peak hours and then would turn on full blast as soon as the off-peak time period begins. One million residential water heaters alone could produce a 4 GW spike in load. If TOU adoption were sufficiently high, this load spike could substantially increase wholesale market prices and overwhelm transmission, distribution and generation assets during the hour after the off-peak rate starts, potentially offsetting any gains made from load reductions during the peak price hours.

What if the loads are equipped with something smarter? If the control devices were designed to optimally control the loads and to preserve customer quality of service, one would get a load spike before the event as the smart devices prepare for the event, load reduction for a fraction of the peak period, and then a second load spike at the end of the event (Fig. 2 shows one example). The result is two new demand

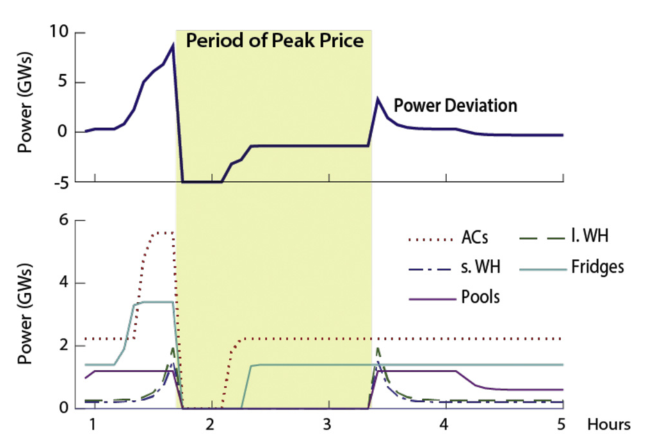

Fig. 2. The optimal response of millions of air conditioners, water heaters, refrigerators and pool pumps to a 90-minute increase in electricity price, given quality of service guarantees (Cammardella et al., 2018). The resulting fast load ramps could become a major headache for grid operators, and many loads are not able to hold their response through long events.

peaks at the beginning and the end of the event period, two periods of rapid load ramping, and load reductions that only persist through the first part of the high-priced period. This behavior is clearly suboptimal from both an economic and a power engineering perspective.

An alternative to the TOU rate is to use a critical peak price (CPP) or peak time rebate (PTR) structure in which the retail price of electricity increases substantially when there are capacity shortages, or customers earn rebates by reducing their consumption during critical peak time periods. These structures have been shown to (at least initially) reduce peak consumption by 5–40% for customers that adopt these rates (Faruqui et al., 2017). Our own experience with critical peak rate pilots (Blumsack and Hines, 2015; Bleything et al., 2015) shows that: (a) CPP responses are not particularly reliable from one event to the next, (b) that customers were frequently confused about how much they were saving (or not saving), and (c) customers were not clear about what actions they could take to make a real difference in their consumption. CPP rates were an effective measure to encourage peak-shifting among customers who stick with them. Our study, however, showed customers opting out of the CPP rate at a fairly high frequency. Increased automation could make these rates more palatable for consumers, but as with the TOU rate, one may still end up with load spikes before and after event periods end, and responses that do not persist through the entire peak period.

Another alternative is real time pricing (RTP), in which hourly or sub-hourly wholesale prices are passed along to homes, businesses and devices. RTP is a closed-loop strategy that addresses one of the shortcomings of TOU rates. Some have argued that consumers will be insulated from risk through automation, but as is the case with TOU rates, automated responses to variable prices in a closed-loop system can produce outcomes that are bad for both consumers and the grid. There is growing evidence that passing wholesale prices to automatically controlled devices could result in system-wide instabilities that could increase volatility, rather than decrease it (Callaway and Hiskens, 2011).

Perhaps most importantly, these time-varying rate structures were designed to align retail costs with periods of peak demand. The goal of the rate design was to avoid the use of high-cost peaking plants, to defer or eliminate the need for capital upgrades, or both. A time varying volumetric rate does not address the cost-recovery problem in a system where cost is dominated by capital rather than fuel. When capacity is the primary driver of cost, customer rate choices should provide a signal to utilities about how much demand there is for new capacity in the future, rather than merely passing the historical and regulator-approved average of capital and operating costs back to customers. In other words, electric rates of the future need to be forward-looking, providing a signal to utilities regarding what investments and kinds of service customers want, rather than merely looking back at the cost implications of the system investment decisions that the utility and their regulators or stakeholders have worked out among themselves.

3. Congestion control and automation

Until the end of the 1980s, balancing supply and demand in the Internet appeared to be an intractable problem: the consumer wants bandwidth, and the more the better. The complexity of the congestion control problem appeared insurmountable. It was recognized early on that a distributed control architecture was needed. Initial attempts failed, leading to a colossal collapse in 1986 in California, which inspired in part the seminal work surveyed in Jacobson (1988). The reliability of communication networks today is the result of a distributed control architecture that began with this early work.

Along with distributed control (local intelligence and automation across the network), communication networks require buffers to help balance supply and demand. In the power grid, this is analogous to storage (e.g. batteries or dams) along with inertia from large spinning generators.

Many loads are also storage devices. The most obvious are water heaters or homes in the winter in cold climates that store (thermal) energy. Power arriving to the water heater is extremely bursty – a typical unit in the U.S. draws over 4 kW for 5 min, and is then off for several hours; yet the water remains within comfortable bounds. The behavior of residential heating and cooling systems is similar. Other deferrable loads that behave like batteries include water pumping (for irrigation or pool cleaning), and even “cow cooling” in locations with dairy farms. Translating this flexibility into virtual energy storage that is reliable and controllable like a battery system requires careful control systems design. Nevertheless, we believe it is no more difficult than the control challenges faced in the early days of the Internet. In our own research, distributed control algorithms have been developed to provide battery-like grid services, while maintaining strict bounds on the quality of service offered to consumers. In fact, these algorithms were motivated in part by Internet control architectures (Almassalkhi et al., 2018; Chen et al., 2018).

There are of course social and economic challenges. Even if the consumer is assured that the new smart water heater will provide hot water just like the old one, and the smart thermostat will keep temperature within strict bounds chosen by the occupant, getting customers to adopt economically beneficial flexible demand systems requires very clear economic incentives and clear communication about the benefits of technology adoption.

New technology that enables flexible demand to act as fully controllable energy storage resources opens up new operational possibilities. More efficient operations could feed into less costly planning decisions if capacity congestion can be reliably avoided during operations. Rate design, however, will need to encourage this symbiosis in capacity congestion control. Electric rates cannot simply be a backward-looking feedback mechanism, in which utilities learn about whether previously made planning decisions were sufficient, but can become a mechanism that improves future planning decisions. These ongoing changes give the utility a unique opportunity to engage with customers in system planning.

4. An alternative: service contracts, not rates

In order to find a plausible alternative to dynamic rates, we again look to the telecommunications industry. Consider, for example, cellular telephone service. As is increasingly the case with electricity, the cellular industry faces very low marginal costs and very high capital costs with constraints that become binding only during peak periods. These peak periods are sometimes hard to predict in advance. Very few, if any, providers actually attempt to pass on the time-varying cost of usage to customers. Instead, the industry as a whole offers a range of contract structures and consumers choose the combination of reliability and capacity that fits with their lifestyle. For example, in the US one can buy a fairly reliable high-bandwidth contract for $100/month from a major cellular service provider or a very low bandwidth, low reliability contract from a pay-as-you-go provider for as little as $100/year. In reality, both plans run on the same physical networks, but the infrastructure owners offer their surplus capacity to the lesser-known service providers at a discounted cost, and then throttle back their bandwidth (leading to less reliable service) when capacity is constrained. Based on customers’ willingness to pay for the more expensive plans from mainstream providers, infrastructure owners get a clear signal regarding how much infrastructure to build. Similarly, Internet service providers sell monthly service contracts with prices that vary not with the total volume of internet usage, but rather with the amount of capacity (bandwidth) that the customer would like to purchase.

Obviously, it would be foolish to reproduce the structure of telecommunications pricing exactly. There is some evidence that existing structures in telecommunications lead to market power that is not good for consumers. But the service contract structure provides a useful guide for reform of retail rate structures in electricity.

Our suggestion is that electric utilities design a portfolio of service contracts that allow customers to choose plans that align with they desire, value and can afford. We have identified several different dimensions along which these service contracts could be differentiated.

- Capacity or service level: What is the minimum amount of power capacity that the customer needs during times of grid congestion?
- Automation: How much demand automation technology is the customer interested to install and how much flexibility is the customer willing to offer to the system through demand management?
- Carbon intensity: How much additional carbon reduction (beyond regional policy goals) does the customer want?
- Local generation: To what extent does the customer want to buy only from local power producers?
- Low income: What level of low-income subsidy is appropriate for this customer?
- Nano-grid: Does the customer only want to use the grid as a last resort backup to their own rooftop solar and battery system?

The concept of replacing volumetric or other rate designs with fixed price service plans has been mentioned before in the literature (see, e.g., Huber and Bachmeier, 2018), as a mechanism to shift risks and enable consumers to express preferences for different levels of service. We argue that the need for service contracts goes beyond these advantages mentioned by Huber and Bachmeier. As the problem of managing capacity congestion becomes more central to utility operations and the potential for automation expands, the service contract rate design becomes the easiest way to align customer preferences with their costs of service.

When customers make choices about capacity and automation, they signal to the utility the extent to which they are willing to have loads automatically curtailed during periods of system congestion and the amount of firm capacity that the utility should build to support this customer's service. For those customers who desire to have a lower carbon footprint than the portfolio that is currently available, or what is required by regulation and legislation, they can choose an option that is less carbon intensive or even net zero. For those who want to support local economic development they can choose an option with a higher contribution from nearby generation sources. Clearly, there should also be a service contract structure for low-income customers to mitigate inequity and ensure energy access. The design and pricing of the low-income package should be informed by existing and future policies around low income and disadvantage communities. For those who have onsite solar and battery systems and thus only need the grid as a back-up or to supplement their own generation, there should be a package that is appropriate for them as well. Based on these differentiators, we should be able to design a portfolio of service contract options that best fit the needs and desires of the customers, within their budget constraints. By choosing service contracts, customers would give the utility a forward price signal regarding the level of service that the utility should plan for and the environmental attributes that they value.

For an illustrative example, a utility could offer a budget plan that would have strict upper limits on customers' peak load, which would be enforced only during periods of capacity shortages, and coupled with automation technology that helps customers to minimize the impact on quality of service for their most critical loads. Or customers could purchase a premium plan, with a higher monthly capacity charge and volumetric rates, with virtually no limits on capacity (as with most standard flat rates today). Or customers could purchase an advanced automation plan that combined an intermediate capacity limit with a wide range of home automation services that would assist the customer in staying within this limit. Since energy is not yet free and volumetric rates do have some efficiency benefits, the rate would most likely include both a monthly charge and volumetric element. Unlike with conventional rates that use a demand charge, capacity limits would only be enforced (first by engaging dispatchable demand) when there were actual capacity constraints on the grid.

4.1. Addressing challenges

We acknowledge that the concept of forward-looking, system-based portfolio of service plans calls for a paradigm shift from current practices. But this paradigm shift is necessary if our industry is to decarbonize and enter an era of zero marginal cost grid. Given the ambitious carbon reduction goals that many US states and countries have set into policy, it is not too early to consider what paradigm shifts are necessary. The time between today and the arrival of zero marginal cost electricity is the runway that we have to identify a revenue model that can be operationalized at scale. Refining the service contract rate structure will require systematically identifying and mitigating concerns and risks. Once concerns, risks and mitigation strategies are identified pilot studies will be needed to validate and refine the assumptions underpinning service contract model. Once the revenue model is de-risked, validated and rigorous, utilities will need to develop implementation strategies and execution plans to ensure a smooth transition, so that customers are not shocked or disadvantaged by sudden changes.

The following are three particular examples of the kinds of rate design challenges that will require careful thinking.

First, electricity and electric rates are already fairly confusing to many customers (Blumsack and Hines, 2015). The service plan concept should not make this worse. Utilities would need to strike the right balance between the number of service plan options and the granularity of those options. Too few options will not give customers opportunities to express meaningful preferences and give planning signals to the utility, while too many options will overwhelm many consumers.

Second, utilities would need to perform careful analysis in order to structure and price service plans correctly. Some attributes of the kinds of service plans we propose would yield different service costs and savings depending on the number of people who sign up for those plans. Pricing service contracts and making investments based on the number of customers that are expected to sign up has the potential to yield stranded costs or revenue shortfalls if those enrollment projections are off by substantial margins. For example, we envision offering consumers a lower service plan rate (other things being equal) if they agree to a high level of automation and demand flexibility. This lower service plan rate reflects the system benefit of avoiding high capacity utilization during peak periods. Such a system benefit, however, would probably decline as the amount of demand flexibility increases. Suppose that the utility prices service plans with automation assuming that perhaps 25% of customers would enroll in such a plan. Now suppose that 90% of customers enroll in the automation plan but are rewarded (with a lower service plan cost) based on the projected system benefit from 25% enrollment. This revenue would need to be made up from somewhere, necessitating the kind of cost recovery or cross-subsidization mechanism that the service plan model seeks to minimize in the first place.

The way in which consumer choice is structured would also need to be carefully considered, particularly if service plan subscriptions are used by the utility as an input to planning decisions. Many utility investments are long-lived, and the traditional business model depends on being able to charge customers for those investments over a long period of time. (It also depends on treating customers as if they care about reliable kilowatt-hours and nothing else.) There is thus some risk of stranded costs if customers are allowed to change service plans frequently and without penalty. This is not fundamentally different than the demand-side risk that utilities face currently, but the utility would need to think carefully about how to manage it. Flexibility in demand may come with a service plan discount, but flexibility in choice of service plans would likely need to come with some penalty to avoid the risk of stranded costs being widely socialized.

Third, utilities will also need to develop mechanisms for enforcing the contracts that customers choose, particularly for the capacity limit element of a service contract. If a customer were unable to keep their load under their demand limit during periods of congestion (perhaps due to insufficient automation technology), there would need to be some feedback to the customer. Both the pricing models used in telecommunications service and some current practices in electricity retailing offer some potential solutions to the enforcement problem. Overage charges and service throttling in telecommunications are both common (if irritating when levied) consequences for over-use that allow the network provider to align costs with service intensity. Electric utilities in Oklahoma and providers in Texas (Eryilmaz and Gafford, 2018) have been experimenting with prepaid electric use, which also features overage charges. In any situation, clear communication with customers is key.

4.2. Benefits

The benefits of the service plan structure to the load serving entity are most obvious: a service plan model can be designed to address the significant fixed costs in this industry, the utility will face less uncertainty regarding infrastructure needs, and the proposed technology component will ensure that demand flexibility is provided without unexpected negative impact on the consumer. And with a portfolio of data about customer service contract choices, the utility should have substantially better data from which to evaluate generation, transmission and distributed energy (non-wires) infrastructure solutions on their relative merits. If well implemented this approach could enable utilities to integrate, operationalize and scale DERs as part of their normal planning, operation and optimization activities. Enabling utilities to make better tradeoffs among wires and non-wires alternatives should provide benefits to a broad range of stakeholders, including (most importantly) electricity customers.

The value to the consumer is realized through the shared benefit of lower infrastructure costs, lower stranded risks and a better way for consumers to signal the kinds of services that they want. Utilities in California today are rapidly building billion-dollar battery systems and supporting infrastructure. These costs could be reduced dramatically with demand-side management, implemented autonomously to eliminate risk to the consumers. In particular, customer bills will be more predictable, relative to complicated dynamic pricing schemes, and grid services from typical retail loads will provide precisely what is expected of them.

5. Conclusions

Retail rate structures need to adapt to ongoing fundamental changes in the cost structure for electric power provision, as well as fundamental changes in the interaction between customers and the power grid. As renewable energy grows, cost structures become more capital-intensive and historically predictable differences between peak and off-peak marginal costs disappear. Increased automation brings terrific potential for the use of end-use appliances for grid balancing and stability, but these technologies are only beneficial if the equivalent of herd behavior can be avoided. The twin challenges of cost recovery and harnessing technical potential for a lower-cost and more efficient power system are unlikely to be entirely solved through wholesale market innovations. Since they are challenges that ultimately affect end-user bills, the way that utilities think about rate-making will need to radically evolve.

We argue that a fundamental shift towards utility rates as cost recovery mechanisms and towards a value-of-service philosophy (Harmon et al., 2009) is the right approach. Utilities should think carefully about how to move beyond the volumetric charge paradigm and towards a system that charges for what customer's value. We do not claim that the design of appropriate service rates will be easy. A great deal of research will be needed to understand what customers really value, and how to communicate the costs and benefits of service options in clear ways.

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