The Future of Electricity Retailing and How We Get There

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Executive Summary

Electricity retailing is at a crossroads. Technological change is eroding revenues from the traditional electricity retailing business model. However, many of these new technologies have the potential to create new products and revenue streams for electricity retailers. We assess the future of electricity retailing under two possible approaches by policymakers and regulators to addressing these challenges and new opportunities: a *reactive* approach and a *forward-looking* approach.

A *reactive* approach would only address the technological changes that (1) actually occur and (2) have a documented negative impact on the electricity supply industry. However, this approach may not result in the adoption of the full range of available technologies or the realization of all of the economic benefits that these technologies can deliver to consumers and producers of electricity.

A *forward-looking* approach anticipates the future products and services these technologies can enable and makes the necessary enhancements to the electricity infrastructure and regulatory rule changes to maximize the expected benefits that electricity consumers and producers can realize. This approach is, however, accompanied by the risk that investments and regulatory changes are undertaken to adapt to a future that ultimately does not materialize.

Consequently, which approach or combination of approaches taken by a jurisdictions to adapt their electricity retailing sector should be based on its existing electricity infrastructure, current regulatory framework, current renewable generation resources, and future regulatory policy goals. This report identifies the key factors that a jurisdiction should consider in formulating a path to the future of its retail sector. Specifically, what initial conditions and policy goals should lead to a more *reactive* approach versus a more *forward-looking* approach. We also identify changes in a jurisdiction's wholesale market design that can enhance the likelihood of success in achieving its future electricity retailing goals.

We first survey the history, current state, and likely future of the new technologies driving change in electricity retailing. The global market for intelligent, interconnected devices, has grown markedly over the last two decades. Innovations like smart meters, direct load control appliances, programmable thermostats, and other *smart home* devices are allowing consumers to monitor and change their energy consumption habits remotely–drastically reducing the effort required to react to price signals or other incentives from their utility. For instance, between 2004 and 2018, the average cost of smart sensors fell by about 66%; smart meter costs fell by 20% in the decade prior to 2006; the prices of lithium-ion batteries–used for home and electric vehicle (EV) energy storage–and Photovoltaic (PV) grade polysilicon fell in price by 85% and 78%, respectively, between 2010 and 2018.

Catalyzed by these price trends and average-cost based pricing of the sunk costs of the transmission and distribution networks, distributed solar has become a major component of the global market for renewable generation capacity. Declining equipment costs and generous financial incentives provided by local, state, and federal governments have increased the cost-competitiveness of distributed solar versus traditional grid-supplied electricity. Because of renewables mandates in many jurisdictions and economies to scale in deploying solar PV capacity, grid-scale solar systems have become far more common and actually surpassed the

cumulative amount of distributed solar installed globally in terms of capacity in 2016. By 2018, a little over 40% of global solar capacity was distributed.

Similarly driven by declining prices for lithium-ion batteries and smart devices, the transportation and heating sectors are poised to become major markets for grid-integration technologies. In an effort to reduce greenhouse gas (GHG) emissions and hedge future fossil fuel price increases, vehicles and heating infrastructure are beginning to switch from traditional fossil fuels to electricity. Combined with innovations in energy storage and distributed generation, electrification of transportation and heating equipment can provide resilience to power outages and price shocks in addition to grid reliability benefits.

We then turn to a discussion of the regulatory barriers to electricity retailing efficiently adapting to these new technologies. Many barriers are the result of the existing regulatory process not creating the necessary initial conditions for many new technologies to be adopted or to be adopted in a cost effective manner. The lack of widespread deployment of interval metering is a prime example of this kind of barrier. Other barriers to change are the result of inefficient prices for regulated services, such as average cost pricing of the sunk cost of transmission and distribution network and annual average cost pricing of wholesale electricity to consumers for a unlimited quantity of energy.

Allowing retail competition in electricity markets is one strategy for cost-effectively deploying these new technologies. Consequently, we survey the current state of retail competition in the United States and globally. Over the past three decades, electricity sectors in the United States have been re-structured through the formation of formal wholesale markets and retail competition. Some states have even implemented retail competition without formal wholesale markets. Outside of the US, countries in Europe, Asia, Oceania, and Latin America have adopted, or are beginning to adopt, with varying degrees of success retail competition in their electricity markets.

In order to further explore the policy options appropriate for various jurisdictions, we conduct an in-depth review of deployment trends for interval meters, distributed solar, and dynamic pricing programs around the globe. Interval meters have experienced strong deployment trends in many developed countries. These meters made up 60.7% of all metering infrastructure in the US in 2019. The European Union has set the ambitious goal of reaching 80% market penetration by 2024–several Member States have already reached or surpassed this level of adoption. Many countries in Asia and Oceania have also reached high levels of interval metering penetration with over 70% in New Zealand and over 90% in China.

Even though we observe strong adoption trends for interval meters, dynamic pricing of electricity is largely still in pilot mode. For instance, only eleven US utilities offered real-time pricing for residential consumers in 2019. Even considering the combined enrollment in dynamic and time-of-use pricing, only 7.1% of US customers had enrolled in 2019. Similar trends are evident in other countries. While smart meters are prevalent in Europe, only eight Member States offered dynamic pricing plans in 2018. There are a few outliers though. For instance, 75% of Spanish residential and commercial customers were on a dynamic pricing program by 2018.

Global deployment of distributed solar generating capacity reached over 200 GW in

2018. Numerous ownership arrangements, generous subsidies, and net-metering tariffs have all made distributed solar an attractive option for consumers of all sizes. We argue that correcting the inefficiencies in the pricing of the sunk cost of the transmission and distribution network is likely to lead significantly more grid-scale solar investment to meet future renewable energy goals relative to distributed solar investments.

With this background, we consider possible futures for electricity retailing. As noted earlier, the widespread deployment of interval meters is a determining factor in a jurisdiction's decision to adopt a *reactive* versus *forward-looking* approach to the future of electricity retailing. We argue that regardless of whether interval meters have been deployed in a region or not, there are several retail market policies that regulators should adopt given these new technologies. These policies are designed to eliminate existing incentives consumers have to take privately profitable actions that increase the overall cost of supplying all consumers with electricity and shift a greater burden of sunk cost recovery on to other consumers. We suggest reforms to transmission and distribution network pricing that significantly eliminate the incentive for this behavior through the use of marginal cost pricing of delivered electricity and recovery of the sunk costs of the transmission and distribution networks through monthly fixed charges. We also suggest a mechanism for setting fixed charges for customers to address the equity concerns associated with this approach to recovering these sunk costs.

Retail competition in the electricity sector has two primary goals. The first is to eliminate the need for regulation of retail prices because customers can switch to a competing retailer if their existing retailer charges too high of a price. The second goal is to facilitate the active participation of final consumers in the wholesale market to limit the cost of serving that customer and potentially reduce the wholesale energy costs associated with serving all customers. We identify a major flaw in retail market regulation in many jurisdictions that virtually ensures consumers do not find it in their economic interest to switch retailers or become active participants in the wholesale market. Because enabling active participation by consumers in the wholesale market is the primary reason for investments in many of these new technologies, correcting this flaw is essential to realizing significant benefits from a *forward-looking* approach to the future of electricity retailing.

We demonstrate that in absence of retail competition regulators face an almost impossible task of trying to determine the set of retail pricing plans that provide incentives for consumers to manage wholesale price risks, protects them from excessive retail prices and allows the incumbent retailer to recover the cost of supplying all of its customers. Even in markets that allow retail competition, how the regulatory process sets the default retail price that consumers face can eliminate any incentive for entry by competitive retailers, supplier switching by consumers, or wholesale price risk management by consumers. We discuss default pricing options for regulators that ensure retail competition achieves the above two goals.

The simple lesson from our analysis is that regulators must treat electricity retailing like any other retail market in the sense that customers face the same default price for their wholesale energy purchases that suppliers of energy wholesale face for their sales–the hourly short-term price. Similar to other markets, there is no requirement that consumers actually pay according to this real-time price. However, if they would like to avoid it, then they must pay a market-determined price that includes the risk premium associated with their retailer managing the associated wholesale price and consumption quantity risk, similar to how short-term price risk is hedged in the market for any other product sold to consumers. We provide several examples of default retail pricing plans that achieve these ends.

Price volatility is common challenge that regulators face when integrating intermittent renewables into their jurisdiction's generating portfolio. Although price volatility that reflects the exercise of market power is clearly contrary to the regulator's desires and should be addressed through a market power mitigation mechanism in the wholesale market. Price volatility due to the increased uncertainty in supply due to a large amount intermittent generation capacity creates revenue streams that can finance investments in storage and other flexible-demand-creating technologies. These technologies can also provide ancillary services, the demand for which, typically increases as the share of intermittent renewable generation increases in a jurisdiction.

We discuss wholesale market design features that both enhance and detract from the revenues streams that investors in these modern technologies can expect to earn. For example, wholesale market designs with capacity-based long-term resource adequacy mechanisms are found to reduce the market revenues that can be earned by these technologies. In contrast, wholesale markets with energy-contracting-based long-term resource adequacy mechanisms and higher offer caps on the short-term market are shown to enhance the market revenues available to investors in these technologies. Multi-settlement locational marginal pricing markets that co-optimize the procurement of energy and ancillary services are also found to provide stronger incentives for the efficient deployment of these new technologies relative to single settlement wholesale market designs that do price all relevant transmission network constraints and other relevant generation unit operating constraints. This conclusion is particularly relevant in jurisdictions with ambitious renewable energy goals.

We find that jurisdictions with limited deployment of interval meters, limited existing distributed solar PV capacity, modest to no renewable energy goals, and wholesale market designs poorly suited to supporting these new technologies should adapt a *reactive* approach to the future of electricity retailing. Jurisdictions with widespread deployment of interval meters, significant distributed solar PV capacity, ambitious renewable energy goals and wholesale market designs (or a willingness to adopt a wholesale market design) well-suited to supporting investments in these technologies should pursue a *forward-looking* approach to the future of retailing.

There are a number of directions for future research for both the reactive and forward-looking looking approaches to the future of electricity retailing. We recommend exploration of the technical and financial viability of demand response programs that make use of WiFi enabled plugs and in-house routers remotely controlled by the distribution utility or the consumer. Additionally, it will be important for regulators to develop administrative frameworks for providing revenues to storage investments for their ability to avoid distribution network upgrades while still allowing these resources to earn market-based revenues in energy and ancillary services markets. Moreover, the widespread adoption of distributed energy resources, EVs, and electric heating necessitate further research on the mechanisms for allowing remote-controlled distribution network-connected resources to sell energy and ancillary services in the wholesale market.

Regions that are best suited to pursuing a *forward-looking approach* should also consider dedicating future research efforts towards evaluating more spatially and temporally granular pricing of distribution network services. A network operator employing distribution locational marginal pricing (DLMP) mechanisms to allocate and price resources in the distribution network holds significant promise for regions with ambitious renewable energy goals. In order to prepare for effective adoption of demand side management programs, these regions can benefit from identifying methods for communicating information to customers in manner that allows them to respond to dynamic price signals without exposing themselves to harmful levels of wholesale price and energy consumption quantity risk.

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7. Possible Futures of Electricity Retailing

This section characterizes the initial conditions and policy goals that are likely to drive a region's decision to pursue a *reactive* versus *forward-looking* approach to adapting to the new technologies impacting electricity retailing. We divide regulatory responses to these initial conditions and policy goals into three groups: (1) adaptations that should occur in all regions, (2) those that can be delayed in regions following a *reactive* approach, and (3) those that should be undertaken under a *forward-looking* approach. Because different regions have different natural resource mixes, different electricity demands, and different energy and environmental policy goals, there is no single optimal future market or regulatory structure for electricity retailing for all regions.

As discussed throughout this report, an important driver of the choice between a *reactive* versus a *forward-looking* approach is the extent of deployment of interval metering technology. Without the ability to measure a customer's electricity consumption at least at an hourly level of temporal granularity, most of these new technologies have little ability to deliver significant economic benefits. Consequently, we will also distinguish between regulatory changes necessary to adopt to these new technologies in all regions, regardless of what kinds of meters customers have, versus the regulatory changes necessary in regions with interval meters.

7.1 Network Pricing Reform: An Urgent Need

All regions, regardless of which metering technology their customers have, should work to reform their transmission and distribution network pricing regime. As demonstrated in Section 3.3, inefficient pricing of the sunk costs of the transmission and distribution network is causing consumers to install distributed solar systems that increase the cost of supplying electricity to all consumers and favors substantially higher levelized cost distributed solar generation resources over lower cost grid-scale solar resources. In addition, the average cost-based pricing of the sunk costs of the transmission and distribution network requires low-income customers with insufficient funds to install a rooftop solar system or insufficient income to own a house (to put a rooftop solar system on) to pay a larger share of the sunk costs of the transmission and distribution network.

Average-cost pricing of the sunk cost of the transmission and distribution network did not induce significant economic inefficiencies in a world without the possibility of investing in a distributed solar PV system because customers had the choice of consuming grid-supplied electricity at an average cost-based price or not consuming grid-supplied electricity. Consequently a consumer facing an average cost-based price, instead of a marginal cost-based price, would purchase less grid-supplied energy at this higher price. The consumer would not disconnect from the grid because the price is above the marginal cost of grid-supplied electricity. With access to solar PV technology, the consumer now has the choice between consuming grid-supplied energy and a significantly more attractive alternative of consuming energy from a rooftop solar system. As shown in Sections 3.3 and 4.1, in many regions the LCOE for a rooftop solar system is less than the average cost-based price of grid-supplied energy because the average sunk cost of the transmission and distribution network and other fixed costs are included in the average retail price.

Because the cost of energy from grid-scale solar facilities is reflected in the price of grid-supplied electricity, the customer's decision to invest in a rooftop solar system to reduce their purchases of grid-supplied energy implies that the customer is choosing to consume more expensive rooftop solar energy instead of less expensive grid-supplied solar energy because of average cost-based pricing of the sunk costs of the transmission and distribution network and other fixed costs.

The most straightforward way to eliminate these incentives for inefficient bypass is to price use of the transmission and distribution grid at marginal cost and recover the remaining sunk costs through a monthly fixed charge. In the case that the customer has an interval meter, the customer would face the hourly wholesale price plus the marginal cost of delivering that electricity to the customer. This marginal cost of delivery accounts for the energy losses incurred from moving the electricity from where it is produced to the customer's premises. Given that annual average transmission and distribution losses in all industrialized countries are less than 10%, this fact is captured by multiplying the hourly wholesale price by 1.1 to the compute an upper bound estimate of the marginal cost of grid-supplied electricity. For customers with mechanical meters, this average hourly marginal cost could be computed as the average wholesale price times 1.1. Pricing the transmission and distribution network in this way would ensure that customers do not have an economic incentive to substitute energy from a rooftop solar system for grid-scale energy or grid-scale solar energy.

Returning to our example from California from Section 3.3, if customers paid for grid-supplied energy at an average price of 4.4 cents/kWh (a conservative estimate of the average marginal cost of energy delivered through the transmission and distribution networks in 2019), they would have no financial incentive to install a rooftop solar system with a levelized cost of energy of 15 cents/kWh. In addition, if they want to consume solar energy, it would be less expensive for them to purchase grid-supplied solar energy at this average marginal cost of wholesale energy rather than to install a rooftop solar system.

Marginal cost pricing of the transmission and distribution network leaves a substantial fraction of the sunk costs of these networks unrecovered. The most straightforward way to recover these costs is through a monthly fixed charge for each customer. The challenge with setting such a fixed charge is limiting the burden on low-income consumers. Charging all customers in the same rate class the same monthly fixed charge would likely impose a significant economic burden of low-income consumers in each rate class. Wolak (2018) proposes an approach for determining this monthly fixed charge based on the customer's annual willingness to pay to purchase electricity at the hourly marginal cost of energy. This mechanism computes the monthly fixed charge based on features of the customer's or that class of customers' annual distribution of hourly consumption. McRae et al. (2019) implement this mechanism using household-level consumption data from Colombia. The authors first show the fiscal burden and economic inefficiency of the existing electricity tariffs and then demonstrate how this new tariff methodology could improve economic efficiency and create incentives for the efficient adoption of clean energy technologies, such as distributed solar, batteries, high-speed electric vehicle charging and electric space heating, while still leaving low-income households better off.

A popular approach to recovering these sunk costs that we *do not* recommend is a monthly demand charge where a customer is charged a $/MW price for their "peak" use of the transmission and distribution grid. Demand charges can be divided into two groups–non-coincident and coincident. A non-coincident demand charge is assessed on the customer's highest use of the transmission and distribution grid as measured by their consumption of electricity during the billing cycle, regardless of when the highest system-wide utilization of the transmission and distribution grid occurs. In other words, if a customer's peak demand hour in the billing cycle occurs at 2 a.m. on a Sunday morning, that customer would be assessed a demand charge based on this consumption level, even though system demand is extremely low during this hour. A coincident demand charge is assessed on the customer's demand during the hour of the billing cycle with the highest system-wide demand.

Non-coincident demand charges are the more common demand charge because they can be implemented with a two-register mechanical meter that measures the customer's peak demand and total consumption during the during the billing cycle. In contrast, a coincident demand charge requires an interval meter because the system demand peak could occur during virtually any hour of the month. The economic inefficiency associated with non-coincident demand charges occurs because a customer's peak demand is not coincident of the system's peak demand.

A non-coincident demand charge creates an incentive for customers to make investments to reduce their peak demand that provide little benefit to system reliability or other electricity consumers in the form of lower wholesale energy costs. For example, investments in storage facilities allow a customer to reduce its peak demand and reduce the magnitude of its monthly non-coincident demand charge, with little or no benefit to system reliability or market efficiency. There are a number companies in regions with customer facing non-coincident demand charges that sell batteries and other customer-peak reducing technologies that are financed in large part through reduced monthly demand charges. These demand charges can easily amount to more than 50% of a customer's monthly bill. Taking the example of Pacific Gas and Electric's A-10 rate, the customer pays an average energy price of 19 cents/kWh but 100 times that amount, \$18.26, in a demand charge.[1] Consequently, for every KW the customer's peak demand can be reduced they save \$18.26 per month. Unless this customer's demand reduction occurs during a high system-wide demand hour, this battery investment only reduces that customer's bill. Other customers have to pay higher bills to make up for the lower demand charge paid by this customer. Consequently, non-coincident demand charges provide incentives for privately profitable battery and load-shifting technology investments that have no economic or system reliability benefit besides allowing that customer to avoid paying as much (as it did before the investment) to recover the sunk cost of the transmission and distribution network.

Coincident demand charges have some economic efficiency properties because they provide an incentive for all consumers to avoid consuming energy during system peaks, which can both enhance system reliability and reduce wholesale electricity prices. However, a coincident demand charge is simply a poor man's version of hourly dynamic pricing. Instead of varying the price each hour of the billing cycle based on the hourly marginal cost of grid-supplied energy, a coincident demand charge only raises the price of consumption (massively) during the single hour or shorter time interval of the billing cycle with the highest system demand. A far more economically efficient solution would be to charge the customer the hourly marginal cost of grid-supplied electricity during each hour of the month. A fixed energy price with a coincident demand charge will likely set the hourly price of energy too low or too high during most hours of the month and massively too high during the single system demand peak of the month.

For all of these reasons, demand charges should be avoided, particularly non-coincident demand charges because they cause privately beneficial investments that simply push sunk cost recovery on to other customers. Hourly marginal cost pricing of grid-supplied electricity has superior economic efficiency properties and should be the default option faced by all customers with interval meters. No customer should be required to pay this hourly price. Customers can opt out if they are willing to pay a market-determined risk premium to avoid this short-term energy price risk. For customers without interval meters, average (for the billing cycle) hourly marginal cost pricing of grid-supplied electricity should be the default price. Again, customers can opt out of this default price if they are willing pay the appropriate risk premium to avoid this price risk.

7.2 If Dynamic Pricing is Efficient, Why Don't Customers Like It?

This section addresses the question of why so few customers in regions with interval meters have voluntarily agreed to pay to manage some or all of their wholesale price risk through a dynamic pricing tariff. Specifically, a default fixed price set to recover the average cost of wholesale energy over the year effectively creates circumstances that ensure that no customer will voluntarily switch to a pricing plan which requires them to bear some hourly price risk. The following simple economic model illustrates this very important point.

[1] See `https://ww3.arb.ca.gov/msprog/asb/workshop/pge.pdf` for this example.

Suppose that customers have preferences over the distribution of hourly retail prices, where $P_r(h)$ is the retail price during hour h, that depend on the mean, $\mathbf{E}(P_r(h))$, and the standard deviation, $\sigma(P_r(h)) = \sqrt{\mathbf{E}[(P_r(h) - \mathbf{E}(P_r(h)))^2]}$, of the distribution of hourly retail prices. Let $U(\mathbf{E}(P_r(h)), \sigma(P_r(h)))$ be the customer's preference or utility function, which is decreasing in both the expected hourly retail price and standard deviation of the hourly retail price.[2] Figure 7.1 plots indifference curves for consumer 0 and consumer 1. Because $U(\mathbf{E}(P_r(h)), \sigma(P_r(h)))$ is decreasing in both of its arguments, the direction of increasing utility is towards the origin. All customers would like to pay a lower expected hourly price and face less hourly price risk.

Consumer 0 is less risk-averse than consumer 1 because, for the same expected hourly retail price, consumer 0 is willing to take on a higher standard deviation in the hourly price. This figure also plots the set of feasible pairs, $(\mathbf{E}(P_r(h)), \sigma(P_r(h)))$, that the retailer can offer in retail pricing plans without going bankrupt. The *Feasible Expected Price and Price Risk Frontier* implies that the retailer must increase the value of $\sigma(P_r(h))$ in order to offer a pricing plan with a lower value of $\mathbf{E}(P_r(h))$.

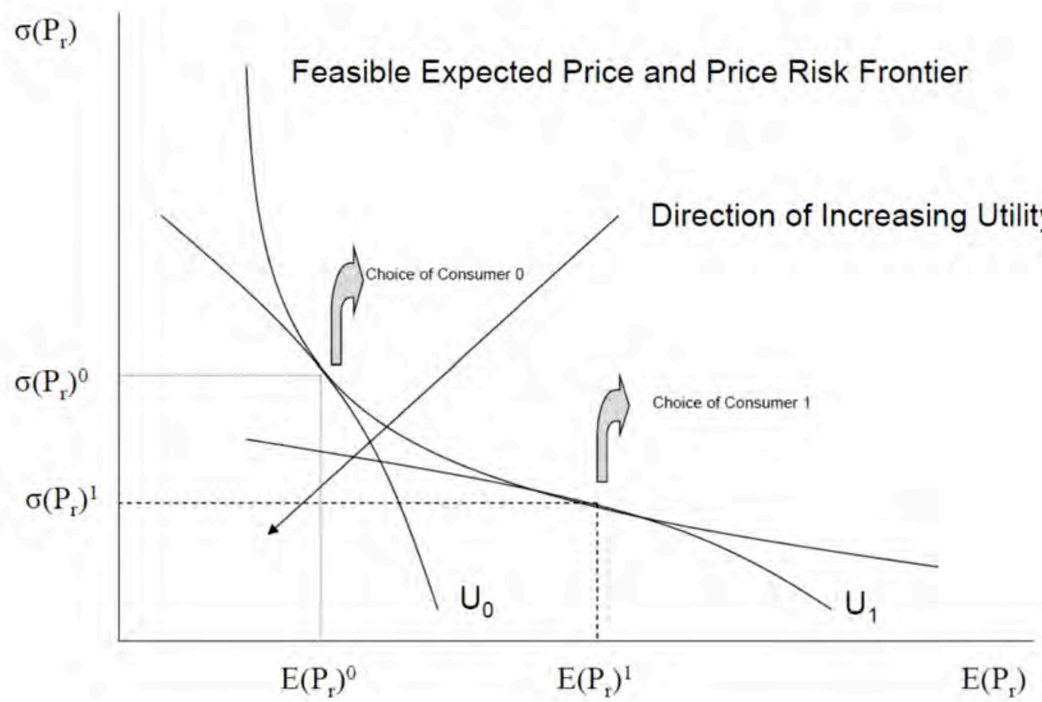

Figure 7.1: Expected Retail Price ($\mathbf{E}(P_r)$) and Standard Deviation of Retail Price ($\sigma(P_r)$) Frontier

The point of tangency between each customer's indifference curve and the *Feasible Expected Price and Price Risk Frontier* yields that customer's expected utility-maximizing

[2]This means that consumers prefer a lower mean hourly price and a lower standard deviation of the hourly price.

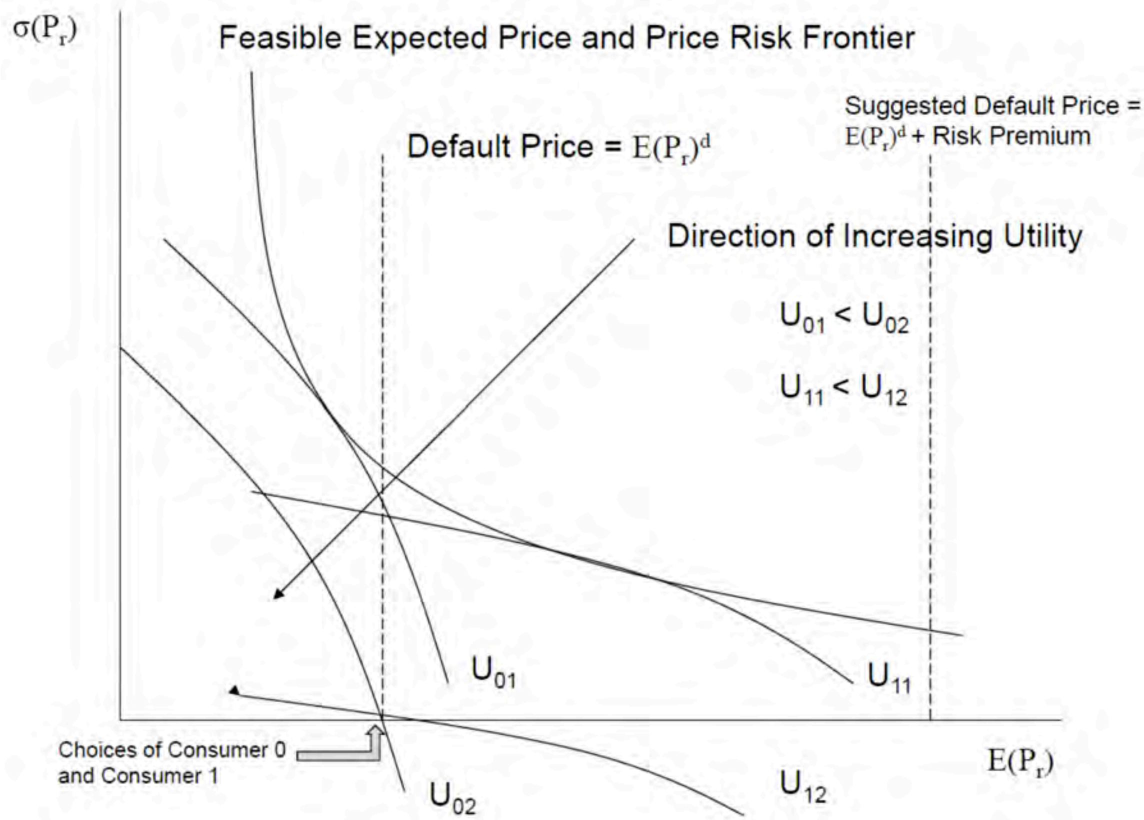

Figure 7.2: Consumer Choices with Default Rate Set at Average Wholesale Price and Suggested Default Fixed Price

pricing plan choice. For customer 0 this process yields the point $(\mathbf{E}(P_r)^0, \sigma(P_r)^0)$ and for customer 1 the point $(\mathbf{E}(P_r)^1, \sigma(P_r)^1)$. It is important to emphasize that the reason each customer chose a plan that required it to take on some hourly price risk is because it faces the default retail rate that is a pass through of the hourly wholesale price, which is the smallest value of $\mathbf{E}(P_r)$ on the *Feasible Expected Price and Price Frontier*, the point where it becomes a vertical line.

Figure 7.2 illustrates the choices of consumer 0 and 1 if a default retail price is set that completely eliminates all retail price risk and recovers at least the average annual hourly price. The original indifference curves for consumers 0 and consumer 1 are drawn as U_{01} and U_{11}, respectively. Two indifference curves with a higher level of utility for each consumer are drawn as U_{02} and U_{12}. These represent the utility levels that consumers 0 and 1 would achieve if a regulated default fixed retail price, $\mathbf{E}(P_r)^d$, was set that eliminated all price risk faced by these two consumers. Because $U_{01} < U_{02}$ (the utility level of indifference curve of U_{02} is greater than the utility level of indifference curve U_{01}) and $U_{11} < U_{12}$, both consumers would achieve a higher level of utility by choosing $\mathbf{E}(P_r)^d$ instead of any point along the *Feasible Expected Price and Price Risk Frontier*.

This model illustrates the extremely important point that, in order for consumers to voluntarily manage wholesale price risk, the default retail price must pass through the hourly wholesale price or the regulator must set a fixed default price that contains a substantial risk premium so that it does not interfere with the choices the customers make along the *Feasible Expected Price and Price Risk Frontier*. This latter point suggests setting the fixed default price given by the vertical line on the far right of the graph. It is equal to $\mathbf{E}(P_r)^d$ plus a substantial positive risk premium to reflect the cost of providing complete insurance against short-term wholesale price risk for the customer's entire annual consumption. It is important to emphasize that this risk premium must be substantial because it must cover the cost of managing both short-term delivered price risk and the quantity risk associated with offering the customer the ability to consume as much as it wants at this fixed price. Particularly during the extreme weather months, offering customers the right to purchase as much as they would like at a fixed price imposes significant quantity risk on an electricity retailer.

Although it is difficult, if not impossible, for the regulator to determine the correct value for this risk premium, the higher it is the more customers will choose a point along the *Feasible Expected Price and Price Risk Frontier* that involves them managing some hourly price risk. Conversely, the lower this risk premium, the more customers will choose this fixed price default option, rather than managing any short-term price risk. Consequently, the level of fixed default price set by the regulator directly determines the extent to which customers are willing to manage some short-term retail price risk.

A major regulatory challenge in regions without effective retail competition is determining the *Feasible Expected Price and Price Risk Frontier* in Figures 7.1 and 7.2. This frontier is the set of expected hourly price and standard deviation of hourly price pairs that recovers all of the costs of serving system demand on annual basis subject to the constraint that consumers can choose any point along this frontier. It is too much to ask for a regulator, or any other single entity, to determine the feasible frontier of pairs of expected prices and standard deviations of price that accomplish this task. The regulator is very likely to set the risk premium on the default fixed price too low so that any of the expected price and standard deviation of price pairs that it requires the retailer to offer are not sufficiently attractive to consumers to cause them to choose these price pairs relative to the fixed default price.

This logic explains why there is so little adoption of dynamic pricing plans in all regulated retail markets and competitive retail markets with a regulated default price option, which includes virtually all retail markets globally. First, there is significant bias towards setting the fixed default price too low to allow effective competition. Second, it is extremely difficult for regulators to determine pricing plans that involve customers managing some hourly price risk that will be chosen by consumers and still allow the retailer to recover the cost of serving all of its customers.

7.2.1 The Role of Retail Competition in Defining the Feasible Frontier

Determining the *Feasible Expected Price and Price Risk Frontier* is the fundamental role of retail competition. However, the major regulatory challenge with creating a competitive retailing sector that determines this frontier is providing customers with actionable information that allows those customers with low switching costs to choose the retailer that offers them their preferred pricing plan. Experience from all retail electricity markets around the world has shown that many customers have high switching costs and are likely to remain with their incumbent retailer, even if new entrants offer lower prices. Consequently, the regulator must balance a desire to protect customers with high switching costs from excessive prices against the desire to allow competition to determine the *Feasible Expected Price and Price Risk Frontier*.

Of the two major approaches to dealing with this issue, the most common one has significantly limited the scope for retail competition and customers managing some wholesale price risk, whereas the other has in fact stimulated retail competition and active management of wholesale price risk. This is largely the result of the fact that regulators find it politically difficult to set the risk premium on the default fixed price high enough for customers to find it in their interest to manage some hourly price risk.

The typical approach to protecting consumers with high switching costs is for the regulator to set a fixed default retail price equal to the average annual wholesale price plus the transmission and distribution network charges and a retailing margin. This is the price $\mathbf{E}(P_r)^d$ in Figure 7.2. This approach was taken in California and most other states in the United States with short-term wholesale markets. It has the advantage of protecting consumers with high switching costs from excessive retail prices. However, this approach has the obvious downside illustrated in Figures 7.1 and 7.2 that it provides no financial headroom for competing retailers to provide lower annual average prices to consumers by managing short-term price risk. Unless customers are paid to switch retailers as was the case in some US states, there is very little entry of competitive retailers. The fixed default price set by the regulator makes the expected profits from entry close to zero.

A default fixed retail price designed to just recover the regulator's estimate of the annual wholesale energy cost of serving a customer has an additional feature that competing retailers cannot offer. Specifically, if this regulator-determined default price turns out to be set too low to recover the actual annual wholesale energy costs of serving all the retailer's customers, the regulator can increase this default fixed price in a future period to ensure that it does. The incumbent retailer is therefore able to offer a price that no other competitor can offer. Specifically, a fixed price or tariff for an unlimited quantity of energy. Because this price is set to recover the expected annual cost of serving the consumer and it is guaranteed by the regulatory process to do so, there is virtually no market for a competing retailer to serve and little incentive for any customer to manage any short-term price risk, even if all customers have interval meters.

If consumers only have mechanical meters, then there is no way for a competing retailer to offer a customer with the ability to shift their demand across hours of the day, week, or month a lower price than the default price. A fixed default price set to recover the annual cost of serving the customer is effective at protecting consumers from excessive retail prices, but it provides little incentive for competitive retailers to enter, particularly in regions with mechanical meters, and little incentive for a customer to choose a tariff that requires them to manage some short-term price risk.

An approach that has worked to stimulate retail competition and active management of short-term price risk is consistent with the logic of a fixed default price with a large risk premium shown in Figure 7.2. This approach establishes what is called *the price to beat*. The regulator sets a fixed default price for retail electricity that is substantially above the sum of the estimated average price of wholesale electricity plus the transmission and distribution charges and the retailing margin. The Electricity Reliability Council of Texas (ERCOT) achieved this outcome somewhat by accident. In the early stage of the state's re-structuring process, the Public Utilities Commission of Texas (PUCT) set a default retail price based on the current price of natural gas. At that time, the price of natural gas in ERCOT was in the range of \$7/MMBTU. As a result of the shale gas boom in the United States, the price of natural gas fell to within the \$2/MMBTU to \$3/MMBTU range in ERCOT. In response, the PUCT did not change *the price to beat* and as a consequence there were significant opportunities, even with mechanical meters for there to be effective retail competition. Despite lower natural gas prices, the PUCT made the decision that *the price to beat* provided adequate protection for consumers with high switching costs against excessive retail prices. Those customers with lower switching cost could shop among competing retailers to obtain an even better deal, often by taking on some short-term price risk. Consequently, the ERCOT approach to introducing retail competition recognized that, in order for vigorous retail competition to occur and customers to shift to retail prices that require them to manage some short-term price risk, retailers need to have the expectation of earning a profit from serving the customer. A fixed default price that built in a substantial risk premium created the opportunity to earn that profit and stimulated the entry to many new retailers in ERCOT. However, by the logic of Figure 7.2, any fixed default price will cause some consumers willing to manage short-term price risk to select the default price option.

The PUCT recognized this logic and when the widespread deployment of interval meters in ERCOT was completed, *the price to beat* was no longer needed and all retailers then had to pay the cost to serve the actual demand of each customer they served, rather than an hourly load-profile of the customer's monthly consumption as was the case with mechanical metering. This is a second important lesson that ERCOT got right, but other jurisdictions such as California did not. Once an interval meter is installed at a customer's premises, the retailer serving that customer should be required to pay the cost of that customer's actual hourly consumption not a load-profiled version of the customer's monthly consumption. This is equivalent to our earlier statement that the default wholesale price that all customers must face is the hourly wholesale price. As a consequence of this requirement, ERCOT has an extremely competitive retail market with many innovative pricing plans offered and among the lowest retail prices in the United States.

In contrast, even after the widespread deployment of interval meters in California, customers are still billed on the basis of an hourly load profile of their monthly consumption. Despite having roughly the same average wholesale prices in ERCOT and California, average retail electricity prices in California are the highest in the continental United States and more than double those in ERCOT. If all retailers must bear the actual cost of serving a customer based on the actual hourly consumption of the customer, retail competition is likely to lead to the retailer with the lowest cost of serving that customer ultimately serving that customer. By the logic of Figure 7.1, if there is no regulated fixed price option, retail competition will also cause customers to choose the expected price and standard deviation of price combination among those available that best suits their retail price risk preferences.

It is important to emphasize that requiring the default retail price to at least pass through the hourly real-time wholesale price is only making explicit something that must be true on a long-term basis: all wholesale electricity costs paid by the retailer must be recovered from retail rates. If this is not the case, then the retailer cannot remain in business over the long term because the price it is charging the consumer for wholesale electricity is less than the average price it pays for this electricity.

Therefore, a standard argument often heard in regulatory proceedings that a prohibition on hourly meters and real-time is necessary to protect consumers from real-time wholesale price volatility does not mean that consumers do not have to pay for their energy at these volatile wholesale prices. They must pay for them on an annual basis or the retailer supplying them will go bankrupt. A regulatory prohibition on hourly meters and a default retail price that passes through the hourly real-time wholesale price only prevents consumers from obtaining a lower annual electricity bill by altering their consumption in response to these hourly wholesale prices—-consuming less during hours with higher than average prices and more during hours with lower than average prices. A fixed retail price requires the consumers to pay the same price for electricity every hour of the year regardless of the wholesale price. For this reason, customers are virtually guaranteed to have a higher annual bills if they face a fixed price or price schedule for their consumption.

A final point to emphasize with respect to the question of all retail customers facing the real-time hourly wholesale price as the default wholesale price component of their retail price is that this same requirement currently applies to all electricity generation unit owners. Unless a generation unit owner is able to find an entity willing to provide a hedge against short-term wholesale price risk, they will sell all of the output they produce in the hour at the hourly real-time price.

Treating final consumers and generation unit owners symmetrically creates the following sequence of market efficiency-enhancing incentives. First, final consumers must sign long-term contracts to obtain a fixed-price hedge against their wholesale market spot price risk. Retailers then would attempt to hedge their short-term wholesale price risk associated with selling this fixed-price retail contract to the final consumer. This creates a demand for fixed-price forward contracts sold by generation unit owners. Therefore, by requiring both generation unit owners to receive, and final consumer to pay the hourly real-time price by default, each side of the market has a strong incentive to do their part to manage real-time price risk.

7.2.2 Symmetric Treatment of Load and Generation

There is significant trepidation among regulators and consumer advocates associated with setting the default wholesale price component of the default hourly retail price for all customers equal to the hourly wholesale price. However, this requirement is no different from the requirement that exists for all other products consumers purchase. For air travel, the customer always has the option to show up at the airport at the date and time she would like to travel and purchase the ticket at the real-time price. However, the customer faces significant real-time price risk with this ticket purchase strategy. The real-time price could be infinite because the flight is sold out. Consequently, the customer hedges this short-term price risk through a fixed-price forward contract, which in the case of air travel is an advance purchase ticket. There are many examples of scenarios where the default price consumers face for a service can be extremely volatile so consumers purchase a hedge against this price risk.

Paying the hourly real-time price as the default price need not lead to much monthly bill volatility. Consider the following monthly pricing plan for wholesale electricity delivered to the customer that achieves the goal of exposing the customer to real-time hourly prices that is very similar to how many US consumers purchase a monthly cell phone service. A customer would purchase in advance various load shapes for delivery to their house at potentially different prices, analogous to how cell phone customers currently purchase minutes of service each month. These delivered wholesale prices would include the marginal cost of delivering the energy through the transmission and distribution networks to the customer plus a retailing margin.

A household might purchase 1 kWh of wholesale energy delivered 24 hours per day and 7 days per week at 4 cents/kWh, 1 kWh of energy delivered 6 days per week for the 16 highest demand hours of the day at 6 cents/kWh, and finally 0.5 kWh of energy delivered 5 days per week for the four peak hours of the day at 10 cents/kWh. This bundle of purchases would give the *Scheduled Consumption* load shape in Figure 7.3. The remaining sunk cost of the transmission and distribution network could be recovered in a monthly fixed charge computed as described in Wolak (2018), as discussed in Section 7.1.

An important component of this mechanism is that the customer is buying a price hedge for a fixed quantity of energy shaped to its hourly pattern of consumption during the billing cycle. Assuming a 30-day month with four weekends yields a fixed monthly delivered wholesale energy bill for this *Scheduled Consumption* load shape of \$55.84 = 30 days/month x 24 kWh x 0.04 \$/kWh + 24 days/month x 16 kWh x 0.06 \$/kWh + 20 days/month x 2 kWh x 0.10 \$/kWh for 1144 kWh, for an average price of 4.88 cents/kWh. The customer faces residual short-term price risk and consumption quantity risk for deviations from this hourly schedule. However, as we discuss below customers can take actions to mitigate the downside of this short-term price and consumption quantity risk.

The jagged line in Figure 7.3 is the customer's *Actual Consumption*. Different from a cell phone plan, if the customer's actual consumption during an hour is less than its scheduled consumption, then the customer could sell the difference in the wholesale market at the real-time price. Conversely, if the customer's actual consumption is above its scheduled consumption, then the customer would purchase the difference at the real-time price. However, the vast majority of the customer's actual consumption is purchased at the fixed average price of 4.88 cents/kWh and only the deviations are bought or sold at the real-time price.

If a customer was concerned about having to purchase at a high real-time price, that customer could purchase more energy in advance at a fixed price and therefore increase the likelihood that its actual consumption would be less than or equal to its scheduled consumption. The customer would sell excess scheduled energy in any hour of the month at the real-time price and thereby reduce its monthly bill. In this way, the customer could purchase insurance against an unexpectedly high monthly bill due to unexpectedly high consumption during the billing cycle, by purchasing more energy in advance. For example, suppose the customer purchased 1.25 kWh for 24 hours per day and 7 days per week instead of 1 kWh. In this case, the customer's monthly wholesale energy bill for this scheduled load shape is $63.04 and the total amount of energy purchased is now 1,342 kWh at an average price of 4.76 cents/kWh. This uniformly higher hourly scheduled consumption shape provides a hedge against the customer having an unexpectedly high monthly consumption by significantly increasing the likelihood that the customer is selling energy back in real-time and thereby reducing its monthly bill.

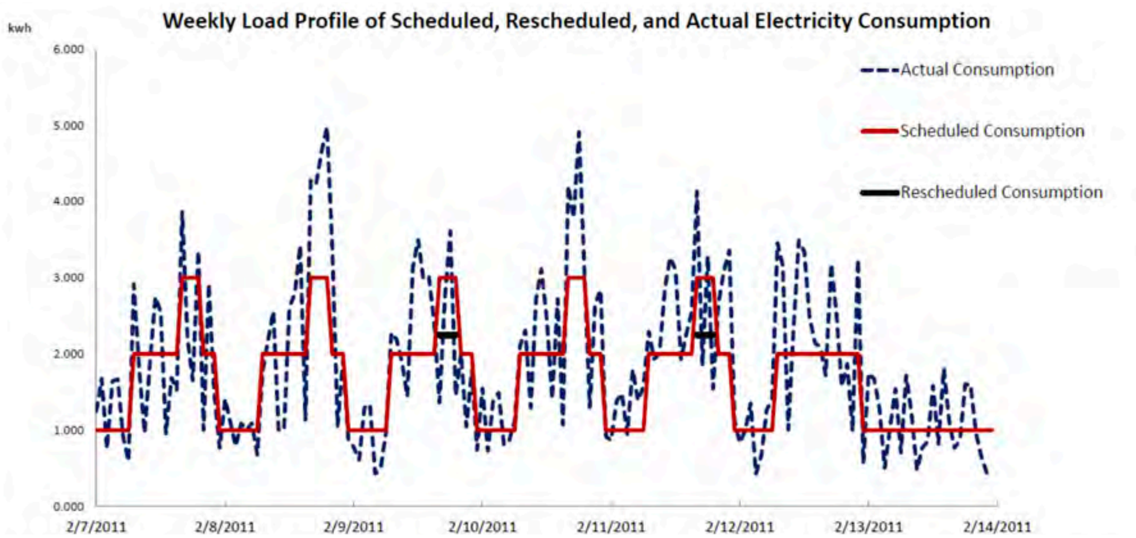

Figure 7.3: Cell Phone Plan Approach to Dynamic Retail Electricity Pricing

NOTES: WEEKLY PATTERN OF HOURLY SCHEDULED, RE-SCHEDULED, AND ACTUAL CONSUMPTION

Several parts of Figure 7.3 contain a short horizontal line during the peak consumption hours of the day labeled *Rescheduled Consumption*. Under some circumstances the customer might want to sell back some of its scheduled consumption in advance of the real-time market on days that it expects to consume less electricity if the price it receives is higher than it expects the real-time price to be. In a two-settlement wholesale market with a day-ahead forward market and real-time market, this could be accomplished through a sale of a portion of the scheduled energy in the day-ahead market.

This example illustrates that it is possible to expose customers to the real-time price for any increase or decrease in consumption without exposing the customer to significant monthly bill risk. This pricing plan functions very much like a monthly cell phone plan were the customer purchases a fixed amount of minutes and must pay a higher price for additional minutes beyond its scheduled minutes for that month. However, different from a cell phone plan, this approach to selling retail electricity allows the price charged for deviations from this scheduled pattern of consumption to be higher or lower than the price the customer paid for its scheduled consumption (depending on the real-time price during that hour) and any unused scheduled consumption can be sold at the real-time price rather than lost or rolled over to the following month as is the case for cell phone plans.

It is important to emphasize that the above approach to purchasing wholesale deliveries relies on the customer having an interval meter. Another important point to emphasize is that as long as the retailer must cover the actual hourly cost of wholesale energy delivered to each customer it serves, the entire process paying for deviations between scheduled consumption and actual consumption described above could be managed by the customer's retailer with no manual intervention by the customer. In this case, the retailer would first receive information about the customer's historical hourly load profile for a number of months. The retailer would then figure out a scheduled load shape to purchase to serve that customer. It could then quote a single fixed price for energy for each month, subject to an overage price for consuming more than the agreed about upon amount. For the customer in Figure 7.3, this could be \$60 and if the customer consumes more than 1,150 kWh during the billing cycle, the customer would pay for those kWh at a penalty price of 10 cents/kWh.

The retailer could offer the customer a discount on this monthly amount if the customer is willing to allow the retailer to install smart plugs to control the electricity flow for several large appliances remotely by the retailer using the customer's WiFi network. One appliance could be the customer's swimming pool pump, which consumes substantial amount of energy when it runs, but must typically be run once per day for a sustained period of time of the retailer's choosing.

By using remotely enabled demand response applied to these smart plugs, the retailer could reduce the wholesale energy purchase costs of the customer and this would allow the retailer to continue to earn the revenues needed to serve this customer at a lower monthly fixed price. In this case, the customer is off-loading the cost of managing the difference between its scheduled and actual consumption to the electricity retailer.

7.2.3 Managing the Transition to Widespread Deployment of Interval Meters

Even in regions without interval meters, a version of the cell phone plan mechanism in Figure 7.3 can be employed. Specifically, customers purchase fixed monthly quantities of energy for the fixed load profiles used to "estimate" their hourly consumption during the month from their measured billing cycle level consumption. For example, the customer could purchase 1,000 kWh that are allocated to hours in the billing cycle according to an hourly load shape set by the regulator. If the customer consumes more than 1,000 kWh in month it would purchase the additional energy at the hourly load profile weighted average of hourly wholesale prices to delivered to that customer. If w_h is the share of billing cycle level consumption consumed in hour h under the load profile and p_h is the hourly delivered wholesale price in hour h, the customer would pay $\sum_{h=1}^{H} w_h p_h$ for each additional kWh consumed during the month. If the customer consumes less than 1,000 kWh in the month, then it could sell the difference between 1,000 kWh and its monthly consumption at this same price. Again, it is important to emphasize that customers are purchasing a hedge against short-term price risk for a fixed quantity of energy and if they consume more than that amount in the month they must pay according to the load-profile hourly real-time price. Similar to the above example for interval meters, customers can hedge this monthly quantity risk by purchasing more monthly energy in advance and selling it back in real-time by not consuming this *Scheduled Energy*.

This mechanism shares many of the features of the cell phone plan approach to managing wholesale purchase price risk, even though it is unable to reward demand reductions during different hours of the the billing cycle differently. A 1 kWh decrease or increase in the customer's monthly consumption is compensated or paid for at the same price: $\sum_{h=1}^{H} w_h p_h$. Consequently, the customer has no financial incentive to shift consumption from hours in the billing cycle with high wholesale purchase prices to hours with low wholesale purchase prices.

This outcome raises the question of how to transition customers with mechanical meters to respond to dynamic wholesale price signals and be willing to adopt an interval meter. One approach is use the environmental motivation to familiarize consumers with the need to reduce their demand when wholesale prices are highest and shift it to when wholesale prices are lowest.

The retailer could communicate with its customers through a cell phone application or web-site the hours when expensive and carbon-intensive generation units are operating and the times when there is likely to be excess of zero marginal cost renewable energy being produced. For example, the retailer could declare, red, *white*, or green hours of the day. Red hours are times when particularly expensive greenhouse gas (GHG) emissions intensive units are operating. Green hours are times when it is likely that an excess of zero marginal cost renewable energy be produced. All other hours would be *white* periods when the consumer should consume neither more nor less energy because of environmental concerns.

Anderson et al. (2019) report on the results from a large field experiment that, with a few hours prior notice, provided Danish residential consumers with dynamic price or environmental signals aimed at causing them to shift their consumption either *into* or *away* from certain hours of the day. They found that the same environmental signal that provided no direct financial compensation to the customer caused substantially larger consumption shifts *into* target hours compared to consumption shifts *away* from target hours. Consumption is also reduced in the hours of the day before and after these *into* target hours and there is weaker evidence of increased consumption in the hours surrounding *away* target hours. The authors find wholesale energy cost savings for the retailer from declaring price and environmental *into* events designed to shift consumption from high demand periods to low demand periods within the day.

7.2.4 The Broader Economic Benefits of Dynamic Pricing

Customers facing dynamic prices can realize economic benefits from shifting their consumption from hours with high wholesale prices to hours with lower wholesale prices, if these actions reduce wholesale prices during the high priced hours and don't significantly increase prices during low priced hours. In addition, customers with flexible hourly demand facing dynamic prices could even agree to a pricing plan that requires them to pay more than the hourly wholesale price during high-priced hours in exchange for even lower prices than the hourly wholesale price during low-priced hours. Customers paying according to this dynamic pricing plan could allow the retailer to reduce the cost of serving other customers and share some of these saving with these customers to compensate them for their actions. Patrick and Wolak (2002) estimate the half-hourly price responsiveness of commercial and industrial customers in the United Kingdom paying for their electricity according to the half-hourly real-time price for electricity. The authors find several customers with significant flexibility in their half-hourly demand that would ideal candidates for this type of dynamic pricing plan.

The actions of these customers can reduce the retailer's total wholesale purchase costs for a given number of total MWh by reducing the retailer's total demand during hours when the aggregate supply curve for the short-term wholesale market is very steep and increasing it in hours when this aggregate supply curve is flat. Consider the following two-period example of a single retailer exercising buyer market power because of these price responsive customers.

Let PW_i equal the wholesale price in period i ($i = 1,2$) and PR_i the price charged to retail customers on the dynamic pricing program in period i ($i = 1,2$). Let $D_i(p)$ equal the demand of dynamic pricing customers at price p in period i ($i = 1,2$). Suppose that the retailer commits to guaranteeing that the demand served on the dynamic pricing contract will provide no contribution to retailer's profits. This imposes the following constraint on the expected profit-maximizing values of PR_i for i = 1,2 that the retailer can charge to these customers:

$$PR_1 \times D_1(PR_1) + PR_2 \times D_2(PR_2) = PW_1 \times D_1(PR_1) + PW_2 \times D_2(PR_2), \tag{7.1}$$

which means that the total payments by customers facing real-time prices, PR_i (i=1,2) equals the total payments the retailer makes to the wholesale market to purchase this energy, because PW_i ($i = 1,2$) is the wholesale price in that hour that the retailer pays for all its wholesale market purchases.

Suppose the retailer maximizes the profits associated with serving customers on fixed retail rates. Let PF equal the fixed retail rate and QF_i ($i = 1,2$) the demand for customers facing the price PF_i in period i. Let $S_i(p)$ equal the aggregate offer curve in period i. The profit function for the firm assuming the constraint (7.1) holds is:

$$\Pi(PR_1, PR_2) = PF_1 \times QF_1 + PF_2 \times QF_2 - PW_1 \times QF_1 - PW_2 \times QF_2.$$

The wholesale price for each period, PW_i is the solution to $S_i(PW_i) = D_i(PR_i) + QF_i$. This equation implies that PW_i can be expressed as:

$$PW_i = S_i^{-1}(D_i(PR_i) + QF_i),$$

which implies that PW_i is a function of PR_i.

The simple two-period model of choosing PR_i to maximize the retailers expected profits can be illustrated graphically. Figure 7.4 makes the simplifying assumption that $D_i(p)$ and $S_i(p)$ are the same for periods 1 and 2. The only difference is the amount of fixed-price load the retailer must serve in each period. Assume that $Q_1 < Q_2$. Define P_i as the value of

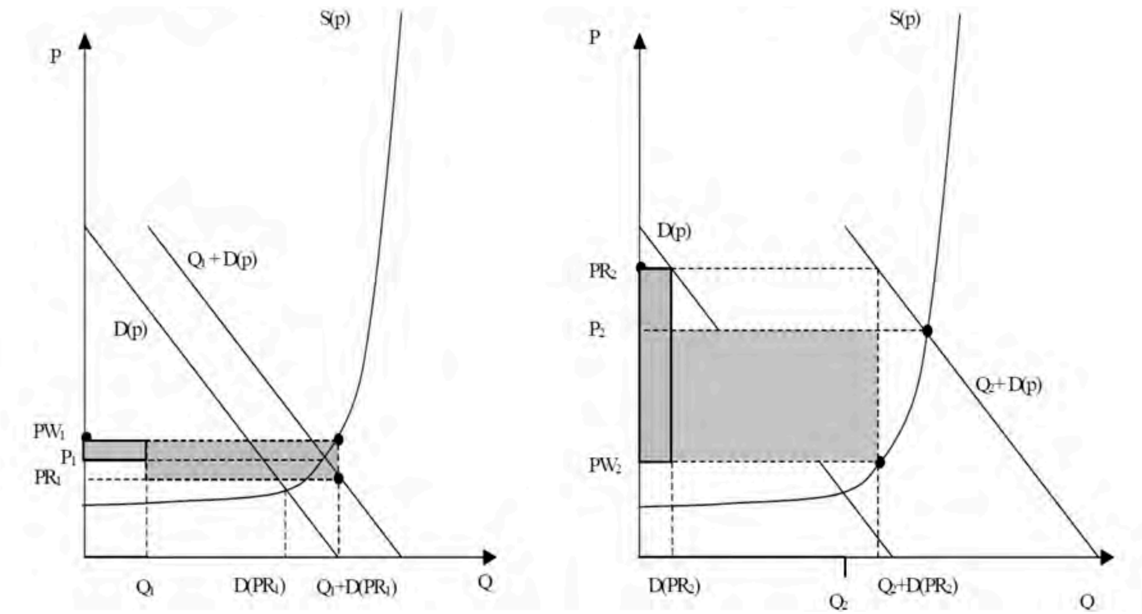

Figure 7.4: Using Dynamic Pricing Customers to Benefit Fixed Price Customers

the wholesale price in period i if the retailer passively bids the real-time demand function $D_i(p)$ in each period. In this figure, PW_i is the wholesale price in period i assuming that the retailer chooses PR_i, the price charged to dynamic pricing customers, to maximize daily profits. The large difference between PR_2 and PW_2 shows the tremendous benefit in high-demand periods from the retailer exercising its market power enabled by serving customers on dynamic pricing plans. In order to satisfy the constraint that the retailer makes less than or equal to a zero profit from serving dynamic pricing customers, the retailer must set PR_1 below PW_1. The two lighter shaded areas in the Period 1 and 2 diagrams are equal, illustrating that the constraint (7.1) given above is satisfied.

The large difference between P_2 and PW_2 versus the relatively small difference between PW_1 and P_1 illustrates the large reduction in daily average wholesale prices from the retailer using its real-time pricing customers to exercise market power versus simply using their demand curves non-strategically. The darker shaded rectangles in the Period 1 and Period 2 figures show the profit increase achieved by the retailer as a result of exercising its buying power enabled by the customers facing dynamic prices. Some of the difference between the large dark rectangle in Period 2 and the small dark rectangle in period 1 can be given to the real-time pricing customers as payment for their price responsiveness efforts.

This strategy for retailers to exercise market power on the demand side of the market extends in a straightforward manner to multiple time periods within the day, week, or month. It represents a major source of potential benefits from a price responsive final demand in the retail segment.

7.3 Price Volatility Supports Flexible Demand Technologies

Regulators and policymakers attempting to transition their electricity supply industries to a larger share of intermittent renewable energy resources must deal with the double-edged sword of price volatility. As Tangerås and Wolak (2019) demonstrate for the case of California, more intermittent wind and solar generation capacity in a region increases the volatility of the net demand–the difference between system demand and output of these intermittent resources–that must be served by dispatchable resources. This increase in volatility of net demand increases the wholesale price volatility which is counter to the regulator's desire to protect consumers from volatile electricity bills. On the other hand, wholesale price volatility creates the revenue streams that can finance investments in many of the modern technologies that can help system operators and consumers manage this wholesale price volatility.

Both storage and load-shifting technologies earn revenues from shifting electricity consumption from high-priced hours to low-priced hours. For example, a 14 kWh battery with a usable energy of 13.5 kWh and a round-trip storage efficiency of 90 percent, would earn $1.03[3] from fully charging at $20/MWh and fully discharging $100/MWh. Figure 7.5 presents average sell prices and buy price offers for transmission network-connected storage units in California by quarter of the year that are following such a strategy.

The larger the difference between the *sell* price and the *buy* for batteries, the larger revenues earned. For example, if the sell price is $1,000/MWh then battery owner earns $13.19 for the same charge and discharge quantities. If the sell price is $10,000/MWh the battery owner earns $134.68 from these same actions. These examples point out importance of a high offer cap on the short-term wholesale market for revenues battery owners can expect to earn. These examples also point out an important property of batteries. They do not produce electricity. They only transfer energy across time. If the wholesale price is constant throughout the day, a battery owner would earn negative revenues because more energy is used to charge the battery than it can discharge.

A necessary condition for earning these revenues is ability to measure injections and withdrawals from the transmission network for the case of grid-scale technologies and the distribution network for the case of the distributed technologies. For the case of the transmission network-connected technologies the existence of these real-time monitoring and measurement devices is typically a necessary condition for interconnection. For the case of the distribution network connected technologies, the customer must have an interval meter (or give direct control over the storage device to the distribution network operator) in order to recover these revenues.

The increased volatility of net demand in regions with significant intermittent wind and solar generation capacity also increases the demand for ancillary services–primary, secondary and tertiary frequency control. Returning to the example of California, ancillary services are the primary source of revenues earned by transmission network-connected storage units. Figure 7.6 presents the quantities of Regulation Up and Regulation Down (California's version of secondary frequency reserve), Spin and Non-Spinning Reserve

[3] $1.03 = 13.5\ \text{kWh} \times \$0.10/\text{kWh} - (14\ \text{kWh}/0.90) \times \$0.02/\text{kWh}$

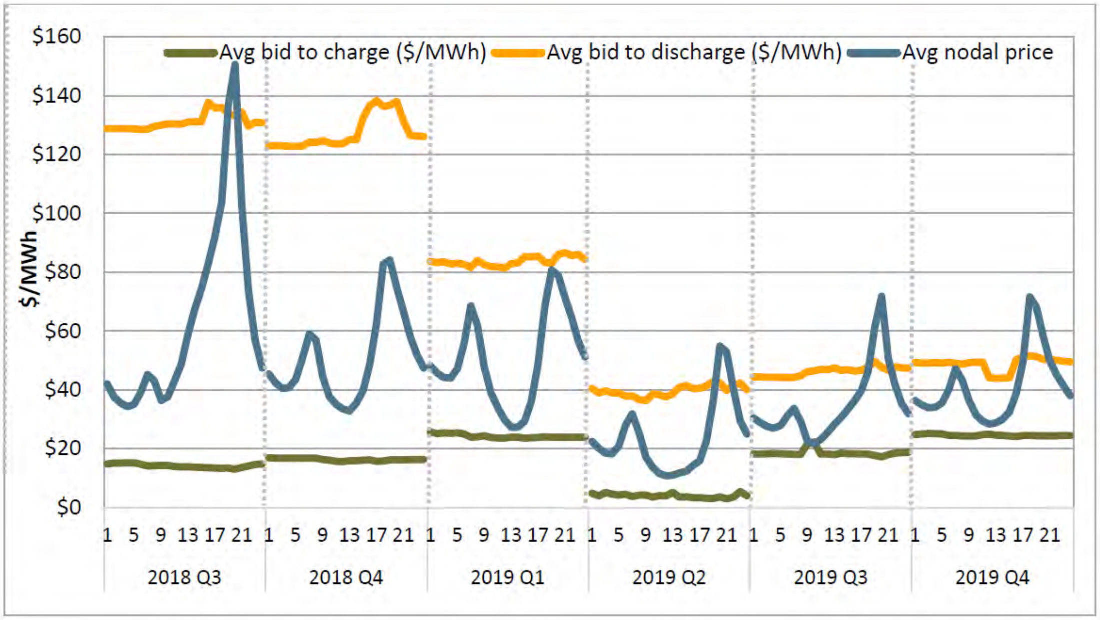

Figure 7.5: Buy (Bid to Charge) and Sell (Bid to Discharge) Prices for Grid-Connected Storage Capacity in California

NOTES: Figure 1.20 from Annual Report on Market Issues and Performance, `http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf`.

(California's version of tertiary frequency reserve), and Flex Down and Flex Up capacity (ancillary services introduced to manage early morning ramp downs and late evening ramp ups of dispatchable resources) and energy sales. A similar picture emerges from Australia, where the majority of battery storage revenues comes from the sale of ancillary services. Figure 7.7 shows the products sold by storage technologies in the Australian electricity market. Although pumped storage facilities primarily buy energy and sell energy, battery units focus their sales on Frequency Control Ancillary Services (FCAS), the Australian Energy Market Operator (AEMO) term for ancillary services.

Batteries and other load-shifting technologies connected to the distribution grid have the ability to provide many of these ancillary services, as well as buy and sell energy. An increasing share of intermittent wind and solar energy in a region can increase the revenues these resources earn both from selling energy and from ancillary services.

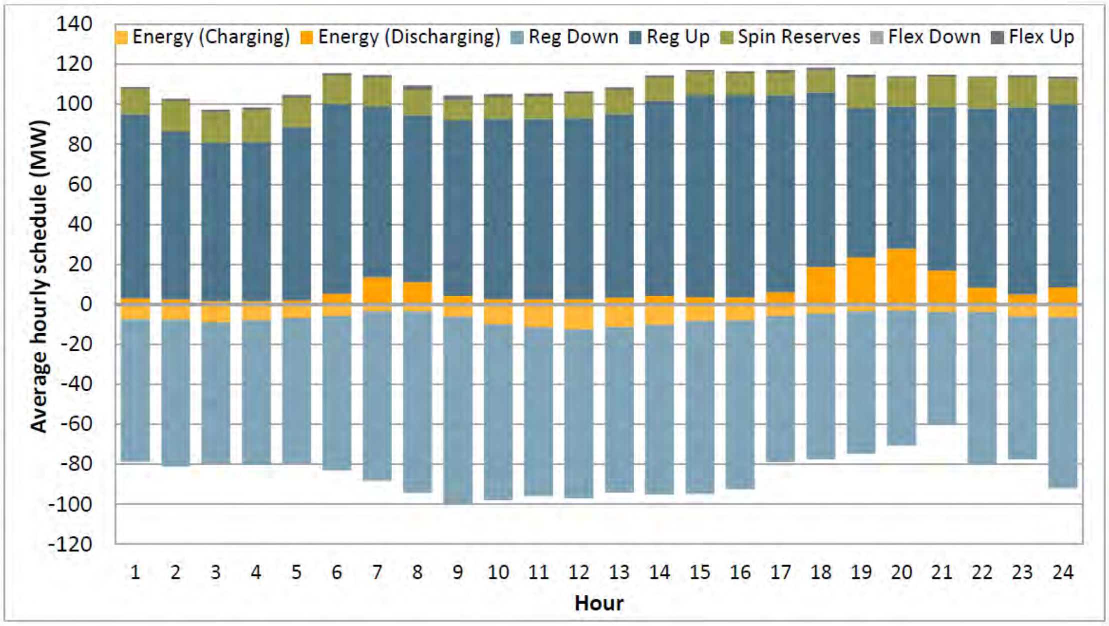

Figure 7.6: Products Sold by Grid-Connected Storage Capacity in California

NOTES: Figure 1.19 from Annual Report on Market Issues and Performance, `http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf`.

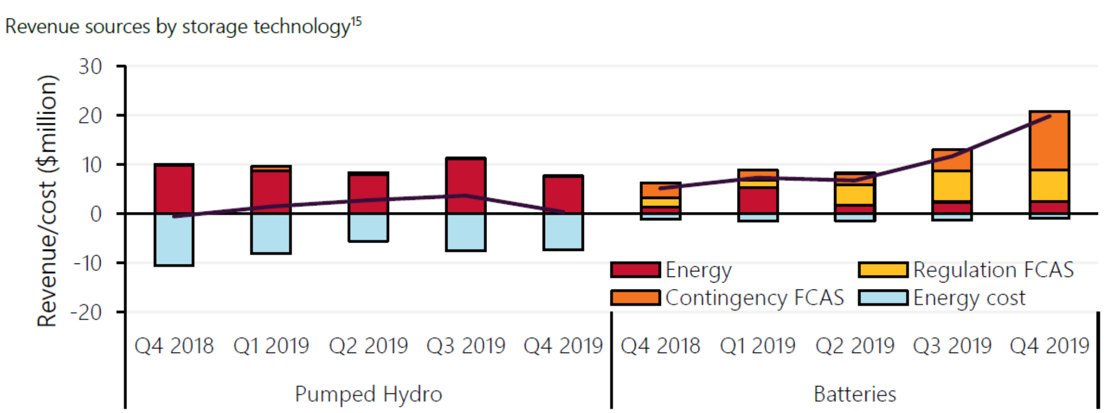

Figure 7.7: Products Sold by Grid-Connected Storage Capacity in California

NOTES: Figure 26 from Quarterly Energy Dynamics Q4 2019, `https://www.aemo.com.au/-/media/files/major-publications/qed/2019/qed-q4-2019.pdf`.

7.3.1 Wholesale Market Designs that Reduce Price Volatility

There are a number of responses by regulators and policy-makers that can significantly reduce the volatility of energy and ancillary services prices, and the level of ancillary services prices, and therefore the revenues that investments in storage and other load-shifting technologies might earn. As we explain below, these actions can ultimately increase annual electricity prices.

Although regulators would like to limit price volatility that reflects the exercise of market power, price volatility that reflects the increased uncertainty in net demand–system demand less the output of intermittent renewable resources–should be reflected in energy and ancillary services prices in order to provide economically price signals for investments in the transmission and distribution network-connected technologies necessary to manage these risks.

Distinguishing between these two causes for price volatility can be extremely difficult and often triggers wholesale market design changes from regulators and policy-makers that unnecessarily increase costs to consumers. Reducing the level of the offer cap on the short-term wholesale market is a popular solution to addressing the problem of price volatility. This has the downside of reducing the range of possible prices and therefore the expected revenues that storage and load-shifting technologies can earn. This dulls the economic incentive for investments in these technologies.

The long-resource adequacy mechanism chosen for the wholesale market can also significantly limit the market for these new technologies. Capacity-based resource adequacy mechanisms that require all retailers to purchase a multiple of their peak demand, typically in the range of 1.15 to 1.20, in firm capacity. The firm capacity of a generation unit is typically described as the amount of energy a generation unit can provide under stressed system conditions. As discussed in Wolak (2020), wholesale electricity markets with capacity payment mechanisms typically have significantly less volatile energy and ancillary services prices because of the firm capacity requirement set by the capacity payment mechanism. These less volatile prices that typically occur in regions with capacity payment mechanisms, provide a much smaller expected revenue stream for investments in storage and load shifting technologies, even in the regions with significant intermittent renewables.

Galetovic et al. (2015) provide empirical evidence on the significant decline in price volatility in markets with capacity payments for the case of the Chile, which operates a cost-based energy market along with a capacity payment mechanism. The authors run a counterfactual simulation of the cost-based market eliminating the capacity payment mechanism but increasing the cost of the shortage parameter used in the cost-based market to dispatch hydroelectric resources to recover the same amount of revenues from energy sales that were actually recovered from energy and capacity sales. The authors find a significant increase in energy price volatility under their counterfactual solution. In addition, a larger share of aggregate generation revenues goes to thermal resources under their counterfactual relative to the existing energy and capacity market design. The authors also report a lower average probability of water shortage occurring under their counterfactual solution.

These results emphasize the following significant downsides of a capacity-based long-term resource adequacy mechanism, particularly in regions with ambitious renewable energy goals. First, by mandating that all retailers purchase a fixed multiple of their peak demand in firm capacity, these markets are unlikely to reduce the total cost of serving demand, because all generation capacity meeting a firm capacity obligation must receive sufficient revenues to recover their total cost or it will exit the market. Consequently, capacity-based long-term resource adequacy mechanisms are likely to raise average prices to consumers for energy, ancillary services and firm capacity in order to accomplish this. Lower energy price volatility reduces the incentives for market-based investments in storage and load-shifting technologies. Under a capacity mechanism more of these storage investments will need to be made through regulatory mandates that further increase total costs to consumers.

7.3.2 The Benefits of a Multi-settlement LMP Market

A financially-firm, day-ahead wholesale market and real-time imbalance wholesale market, both of which a employ locational marginal pricing (LMP) design, can significantly increase the revenues earned by storage and load-shifting technologies. As noted in Wolak (2020), this market design also rewards the dispatchability of thermal resources relative to intermittent renewable resources. Moreover, because it prices the transmission network configuration and other relevant generation operating constraints, prices can differ both spatially and temporally.[4] Because market-clearing occurs twice–on a day-ahead basis and in real-time–this market design feature is called a multi-settlement.

Under this market design, electricity retailers can purchase energy in the day-ahead market that they subsequently sell in the real-time market, thereby eliminating a major difficulty associated with facilitating active demand response in wholesale markets. Single settlement markets require a counterfactual level of consumption relative to which demand reductions are measured. Specifically, the market operator needs to know what the demand response provider would have consumed if the demand response signal had not be given. In a multi-settlement wholesale market, there is no need for the market operator to compute this counterfactual consumption baseline. The retailer can purchase 100 MWh in the day-ahead market at the day-ahead price and if the real-time price is significantly higher, consume less than this amount, say 80 MWh, and effectively sell the remaining 20 MWh in the real-time market at the real-time price.

Bushnell et al. (2009) discuss the downside of the demand response programs that rely on an administratively-set baseline to measure and compensate for demand response. This approach causes demand response providers to focus their efforts on increasing their administrative baseline rather than on providing a reliable reduction in demand that is equivalent to an increase in generation unit output. For example, under a single settlement real-time market, if a retailer is selling demand reductions, this must be measured relative to some value set by the system operator and regulator. However, there is no way for a system operator or regulator to know what the retailer would have consumed had it not been asked to reduce its demand. Electricity meters can only record a customer's actual consumption, not its hypothetical consumption without a demand response signal.

[4]These generation unit operating constraints include ramp rates, minimum safe operating level, minimum uptime and downtime.

The following example illustrates the problem faced with setting administrative baselines. Suppose a retailer has a large customer that sometimes shuts down for the weekend, so the retailer's demand is either 10 MWh or 12 MWh, depending on the customer's decision. The retailer could sell a demand reduction of 2 MWh on the weekends that it knows the large customer shuts down. However, it is important to emphasize that the retailer is not really selling a price-responsive demand reduction because the customer's decision to shut down for the weekend is independent of the price of electricity. This demand reduction occurs regardless of the retailer's sale of a demand reduction. This example demonstrates that under administrative baseline approaches to demand response consumers can pay for demand reductions that they would get without a demand response program.

With a day-ahead market the retailer can purchase its demand-response baseline in the day-ahead market at the day-ahead price and then sell energy in the real-time market at the real-time price relative to this baseline by consuming less than the baseline amount of energy. Another cost of administrative baseline approaches to demand response is that some or all of the payments for these demand reductions must be recovered from an additional charge assessed on all demand. That is because under this approach to demand response, the retailer does not purchase the energy that it subsequently sells in real-time. It simply sells demand reductions relative to this administrative baseline. In a multi-settlement market there is no need for this additional cost paid by demand, because all revenues earned by demand response providers come from purchases in the day-ahead market that are not consumed in real-time and therefore sold at the real-time price.

The existence of a day-ahead market also allows storage units to secure the price at which it will charge and discharge the following day. Because a significantly larger number of generation resources are able to sell in the day-ahead market than in the real-time market, day-ahead prices tend to be significantly less volatile than real-time prices, as shown in Jha and Wolak (2019) for the case of the California market. Consequently, with a day-ahead market a storage owner can predictably buy at a low price in the day-ahead market and sell at higher price in the day-ahead market. This more reliable price differential within the day-ahead is likely to increase the expected revenues a storage owner can earn from energy sales, relative to the case that storage owners buy and sell energy in real-time market, where these within-day hourly price differences are much less predictable.

Multi-settlement LMP markets typically co-optimize the procurement of energy and ancillary services in the day-ahead and real-time markets. This means that the market-clearing mechanism determine sales quantities and locational prices by minimizing the as-offered cost of meeting the demand for energy and all ancillary services. Consequently, co-optimization of energy and ancillary services procurement in the day-ahead ensures the generation and storage resources are used in the most cost-effective manner given their energy and ancillary offers in both the day-ahead and real-time markets. As shown in Figure 7.6, virtually all of the ancillary services sold by storage units in California were through sales in the day-ahead market. As shown in Figure 7.5, virtually all of the energy purchases and sales by storage units were done in the day-ahead market.

An addition benefit of an LMP market design is that locational marginal prices tend to be higher and more volatile in or near major load centers which provides an additional source of revenues for distributed storage and load-shifting technologies to locate near these pricing points. Locating these technologies in or near major load center has the additional benefit that it may reduce the need for future transmmission and distribution network upgrades.

7.3.3 Wholesale Market Design for Forward-Looking Future of Retailing

As noted in the previous section, a multi-settlement locational marginal pricing market supports the efficient deployment of storage and other load-shifting technologies as well as the active involvement of final consumers in the wholesale market. Locational marginal prices (LMPs) of energy will increase the incentive for distribution network level investments in distributed generation, storage and load-shifting technologies. LMPs are typically higher and more volatility near load major load centers. These higher and more volatile LMPs make investments in these technologies more financially viable.

Another important market design feature that supports the deployment of storage and other load-shifting technologies is an energy-contracting based approach to long-term resource adequacy rather than capacity-based approach. With virtually all demand hedged by fixed-price and fixed-quantity long-term contracts between generation unit owners and electricity retailers, regulators can allow higher offer caps on the short-term market.

These higher offer caps allow for the possibility of large price swings within the day which provides greater financial rewards to storage and load-shifting technologies as discussed in Section 7.3. With these investments in place, this market design has the potential to lead to lower annual average wholesale prices. That is because the larger quantity of storage capacity and greater deployment of load-shifting technologies allows the market to get by with less generation capacity to provide the same annual amount of energy.

Taking the example of California makes this point clear. The average hourly amount of energy consumed in the California ISO control area in 2017 was 26,002 MW and the peak demand was almost double that amount of 50,116 MW. This implies that if the demand for withdrawals from the grid where completely flexible across hours of the year, California could get by with significantly less generation capacity because it would only have to meet an hourly demand of 26,002 MW every hour of the year, instead of meeting a system peak of 50,116 and demand levels near that during a few hours of the year. California can get closer to these solution and thereby reduce its need for generation capacity through dynamic pricing which rewards consumers for shifting their withdrawals from the grid from high-priced hours to low-priced periods. This means that energy prices would have to recover less fixed costs of generation capacity on an annual basis, which means average electricity prices could be lower than they would be in market that had significantly more generation capacity.

Markets with a capacity payment mechanism in place typically have lower offer caps and more installed capacity, which implies that total annual payments for electricity generation must be higher to serve the same annual amount of energy, because wholesale price do not vary as much throughout the day, month or year, so that dynamic pricing is unlikely cause as much shifting of this demand away from high-priced periods to low-priced periods.

Consequently, assuming that all generation capacity necessary to serve demand must recover its annual costs, if less generation capacity is necessary to serve demand under a energy-contracting approach to long-term resource adequacy relative to a wholesale market with a capacity payment mechanism, annual average prices can be lower under the former market design. Moreover, having a higher offer cap on the short-term market makes the potential revenues to batteries and load-shifting technologies much which can allow the same annual demand to be served with even less generation capacity by the above logic.

As the discussion of this section makes clear, spatial and temporal price differences provide the essential economic signals for deploying and paying for the full range of technologies that will facilitate a least cost transition to a future retail sector that benefits both electricity consumers and suppliers in regions with significant intermittent renewable energy goals.

7.4 Reactive vs. Forward-Looking: Determining Futures for Retailing

Two key determinants of the choice between reactive and forward-looking approaches to the future of retailing are the widespread availability of interval meters and current and future deployment of distributed solar. For regions without interval meters, little current deployment of rooftop solar systems, and little likelihood of future deployment of rooftop solar systems, there is little need to change the existing model for electricity retailing, besides reform of transmission and distribution network pricing.

As discussed in Section 3.3, transitioning to a marginal cost of delivered electricity approach to pricing retail electricity with a monthly fixed charge based on the customer's willingness to pay for electricity at this price eliminates the existing inefficiency in average cost pricing of grid supplied electricity. Customers will not have a financial incentive to engage in inefficient bypass of grid-supplied electricity by installing a rooftop solar system. Because they do not have interval meters, customers can only be charged for their average marginal cost of grid-supplied energy during the billing cycle based on a representative fixed-load shapes for that customer class.

For the reasons discussed in Section 7.2, customers must face this average marginal cost of grid-supplied electricity during the billing cycle as their default price. This does not mean that any customer must pay this price for electricity. In the case of a regulated retail market, monopoly retailers can offer other pricing plans that provide a hedge against this wholesale price. However, as discussed in Section 7.2, it is virtually impossible for the regulator to determine the *Feasible Expected Price and Price Risk Frontier*. Any attempt by the regulator to set this frontier is likely to lead to everyone choosing the fixed default price.

This approach to transmission and distribution network pricing will encourage the efficient deployment of electric vehicles and the electrification of space heating. Continued average cost pricing of transmission and distribution network services will significantly dull the incentive for customers to purchase and drive electric or plug-in hybrid vehicles. Take the example of California and a plug-in hybrid Prius that gets 50 miles per gallon or 2.2 miles per kWh. Assuming at $3.50/gallon price of gasoline implies a 7 cents per mile cost of driving with gasoline. Pricing electricity at the average Northern California price of 22 cents/kWh implies a 10 cents per mile cost of driving the Prius with electricity. However, if grid supplied electricity is priced at its average marginal cost for 2019 of 5 cents per kWh, the price per mile of driving with electricity falls to 2.3 cents per mile. Consequently, marginal cost pricing versus average cost pricing of grid supplied electricity changes the least cost input fuel from gasoline to electricity, which significantly increases the incentive for adoption of electric and plug-in hybrid vehicles. Similar logic applies to the case of transitioning to electric space heating. Marginal cost pricing of grid supplied electricity will encourage the adoption of electric space heating relative to fuel oil space heating.[5]

Retail competition, even in the absence of interval meters, puts the economic forces in place for retail competition to find *Feasible Expected Price and Price Risk Frontier* if all retailers are charged for the billing-cycle-level consumption of the customers they serve at the hourly marginal cost of delivering grid-supplied electricity to each that customer using that customer's regulator-assigned fixed load profile. This regulatory rule without a fixed-price regulated option or a sufficiently high fixed *price to beat* option will encourage retail competition and provide incentives for customers to manage their demand in response to these prices. Moreover, even customers without interval meters facing this default cost for their retailer to serve them may be willing to provide dynamic demand response through remotely controllable load by their retailer.

Under such a scheme, the retailer could offer customers a discount on their monthly bill for agreeing to have certain large appliances curtailed remotely by their retailer a pre-specified number of times during the month. This could be accomplished through smart plugs remotely accessed through the customer's WiFi network. This business model could be extended to the retailer offering to control remotely a customer's distributed solar or battery system in exchange for discounted grid-supplied electricity. In the absence of an interval meter on the customer's premises, retailers must resort to direct load control methods to deliver reliable demand changes within the billing cycle that can be monetized through sales in the wholesale market.

Even in a retail market without interval meters, there is one action that policymakers can take to foster competition in the electricity retailing. Encouraging the development of an active forward market for energy and adopting a multi-settlement wholesale market design with a day-ahead and real-time market. Wolak (2019) documents the retail and wholesale market benefits of introducing standardized, forward contracts for energy in the Singapore electricity market. In April 2015, Singapore introduced an anonymous futures market for wholesale electricity that sold standardized quarterly futures contracts and making deliveries up to eight quarters in the future. Using data on prices and other observable characteristics of all competitive retail electricity supply contracts signed from October 2014 to March 2016, Wolak (2019) finds that a larger average quantity of open futures contracts that clear during the term of the retail contract a month before the retail contract starts delivery predicts a lower price for the retail contract. This outcome is consistent with increased futures market purchases by independent retailers causing lower retail prices. Consistent with the logic in Wolak (2000) that a larger volume of fixed-price forward contract obligations leads to offer prices closer to the supplier's marginal cost of production, Wolak (2019) finds that a larger volume of futures contracts clearing against short-term wholesale prices during a half hour

[5]The problem becomes more complex relative to natural gas because the natural gas transmission and distribution grid is also priced on an average cost basis. Consequently, both natural gas and electricity should be compared on the marginal cost of heat basis.

predicts a lower half-hourly wholesale price. Both empirical results support introducing purely financial players to improve both retail and wholesale market performance.

Having a formal day-ahead market that these futures contracts clear against rather than having them clear against the real-time market price can further increase liquidity in the forward market because, as noted earlier, day-ahead prices are significantly less volatile than real-time prices even though the sample means of both prices are typically not statistically different from zero after accounting for the cost of trading day-ahead versus real-time price differences, as noted by Jha and Wolak (2019).

A final issue concerns automating the process of comparison shopping. Customers should be provided with machine-readable and shareable access to their electricity consumption data to allow them to comparison shop. A number of jurisdictions have set up price comparison web-sites to facilitate the comparison shopping. Customers can shop for retail electricity according to the pricing plan, renewable energy content, and when the electricity is consumed. They can also enter features of their electricity consumption and obtain a price quote from different retailers or obtain the lowest cost retailers for the consumption information provided. In ERCOT this website is called Power to Choose (http://www.powertochoose.org/). In New Zealand it is called Consumer Powerswitch (https://www.powerswitch.org.nz/). Establishing such a website will facilitate retail competition and can be voluntarily financed by the industry as in New Zealand or required by the regulator as is the case in ERCOT.

7.4.1 Forward-Looking

Regions with widespread deployment of interval meters and regions with significant rooftop solar systems or ambitious renewable energy goals should consider a forward-looking approach to the future of retailing. This approach will maximize the economic and reliability benefits of these new technologies in electricity supply industries with significant amounts of wind and solar resources connected to the transmission and distribution networks.

As discussed in Section 7.2, these regions must reform their approach to transmission and distribution network pricing and require all retailers to pay for the actual hourly cost of delivering grid-supplied electricity to that customer during each hour of the billing cycle. For the reasons discussed in Figure 7.2, there should be no fixed price default price, unless it contains a substantial risk premium, similar to the ERCOT *price to beat*. With these initial conditions in place, retail competition should be encouraged as the most effective way to define the *Feasible Expected Price and Price Risk Frontier* described in Section 7.2.

The widespread deployment of interval meters enables two approaches to allowing consumers to become actively involved in the wholesale market. The first approach is through direct load control by the retailer using technologies installed on the customer's premises. In this case, the retailer bears the entire risk that the demand response actions that it takes will be cost-effective relative to payments or discounts being provided to the customer. This approach is available even if the customer does not have an interval meter.

The second approach allows the retailer to share the risk that demand response actions taken will be cost effective. The retailer can shed some of this risk by sending a price signal and allowing the customer to respond to this price signal. For example, rather than installing direct load control devices on the customer's premises, the retailer can simply charge the customer dynamic price and allow the customer to decide whether it makes economic sense to respond manually or by installing an automated response technology.

Similar logic applies to the case of the decision to install a rooftop solar system with or without battery storage. Without interval meters, the retailer must have direct control of these devices to alter the customer's demand for wholesale energy and thereby reduce the cost of serving the customer. However, with interval meters, the retailer can use dynamic price signals to provide the incentive for the customer to manually respond to these prices or to install the necessary automated response technologies.

An important role for regulatory policy is to provide information that reduces the cost of the customers switching electricity retailers and increases their "energy intelligence" making it more straightforward for customers to determine the best combination of grid-supplied and distributed energy and pricing plans to meet their energy needs. Allowing customers access to their hourly consumption data enables them to make this data available to competing retailers and other third parties. Providing this information in a machine readable and consumer friendly format will allow customers to comparison shop among retailers for their energy services. Rooftop solar system sellers already use this kind of information to determine whether a customer might benefit from the installation of a rooftop solar system. This information would also be useful for suppliers of combined solar and battery systems.

In regions with widespread deployment of interval meters, marginal cost-based pricing of grid-supplied electricity with a monthly fixed charge to recover the sunk costs of the distribution grid, and the requirement that all retailers must recover the actual hourly cost of serving each of their customers, electricity retailers should think of themselves as suppliers of energy services, rather than simply suppliers of grid supplied electricity. Retailers could offer combinations of distributed generation, storage and load-shifting technologies that best meet their customers needs. For example, customers interested in making an environmental statement may wish to install rooftop solar panels and a battery even though these investments may not be the least cost way to meet their energy needs. By either working with distributed solar and battery providers the retailer to could offer a one-stop shopping experience for a retail consumer.

Electricity retailers could also expand into the provision of an in-home high-speed electric vehicle charger and electrification of home heating. In short, once the above three requirements for a level playing field for electricity services providers has been established, electricity retailers should consider themselves energy services providers. Particularly in regions with policy goals for electrifying their vehicle fleets and dwelling heating needs, this could be an extremely lucrative new offering for electricity retailers.

Regions with ambitious renewable energy and vehicle and space heating electrification goals are likely candidates for even more forward-looking policies. Specifically, these regions could install DERMSs to allow retailers to manage distributed solar, battery, vehicle charging and space heating and cooling systems. The DERMS could be installed as a regulated distribution network service that all retailers could have access to under terms and conditions set by the regulatory process.

The logical next step in opening up the distribution networks for competition between electricity retailers would be to establish dynamic distribution network prices as discussed in Section 8.4. A Distribution System Operator (DSO) model could be introduced to provide Distribution Locational Marginal Prices (DLMPs). This would improve the efficiency of pricing delivered grid-supplied electricity, because these DLMPs would price constraints within the distribution network and marginal losses incurred to deliver electricity from the transmission network. Because marginal losses are increasing at an increasing rate in the distance traveled, by including marginal losses in the DLMPs, less of the sunk costs need to be recovered in monthly fixed charges and more can be recovered from marginal losses.

A DSO model for the distribution network could also allow distribution connected resources to provide ancillary services to the wholesale market. For example, distributed solar systems, batteries, high-speed vehicle chargers, and electric space heaters could be equipped with monitoring and control equipment that could allow these devices to provide frequency control services. The prices paid for these services could be computed as part of the DSO price-setting process.

Many of the practical details of transitioning to this DSO model are topics for future research discussion in 8.4. This approach provides a coherent framework for significantly increasing the efficiency of the planning and operation of distribution networks with significant amounts of distributed solar, batteries, high-speed electric vehicle charging and electric space heating.